APS

Scott A. Bauer
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Regulatory Affairs
Palo Verde Nuclear
Generating Station

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Phoenix, AZ 85072-2034

10 CFR 50.71(b)

102-05377-SAB/TNW/CJJ
November 17, 2005

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Submittal of 2004 Annual Financial Reports

Pursuant to 10 CFR 50.71(b), enclosed please find copies of the 2004 Annual Financial Reports for the Participants who jointly own PVNGS. These Participants are Arizona Public Service Company, Salt River Project, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Southern California Public Power Authority, and Los Angeles Department of Water and Power.

No commitments are being made to the NRC by this letter. Should you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

Scott A. Bauer

Enclosure

SAB/TNW/CJJ/ca

cc:	B. S. Mallett	NRC Region IV Regional Administrator (w/o Enclosure)
	M. B. Fields	NRC NRR Project Manager (w/o Enclosure)
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS (w/Enclosure)

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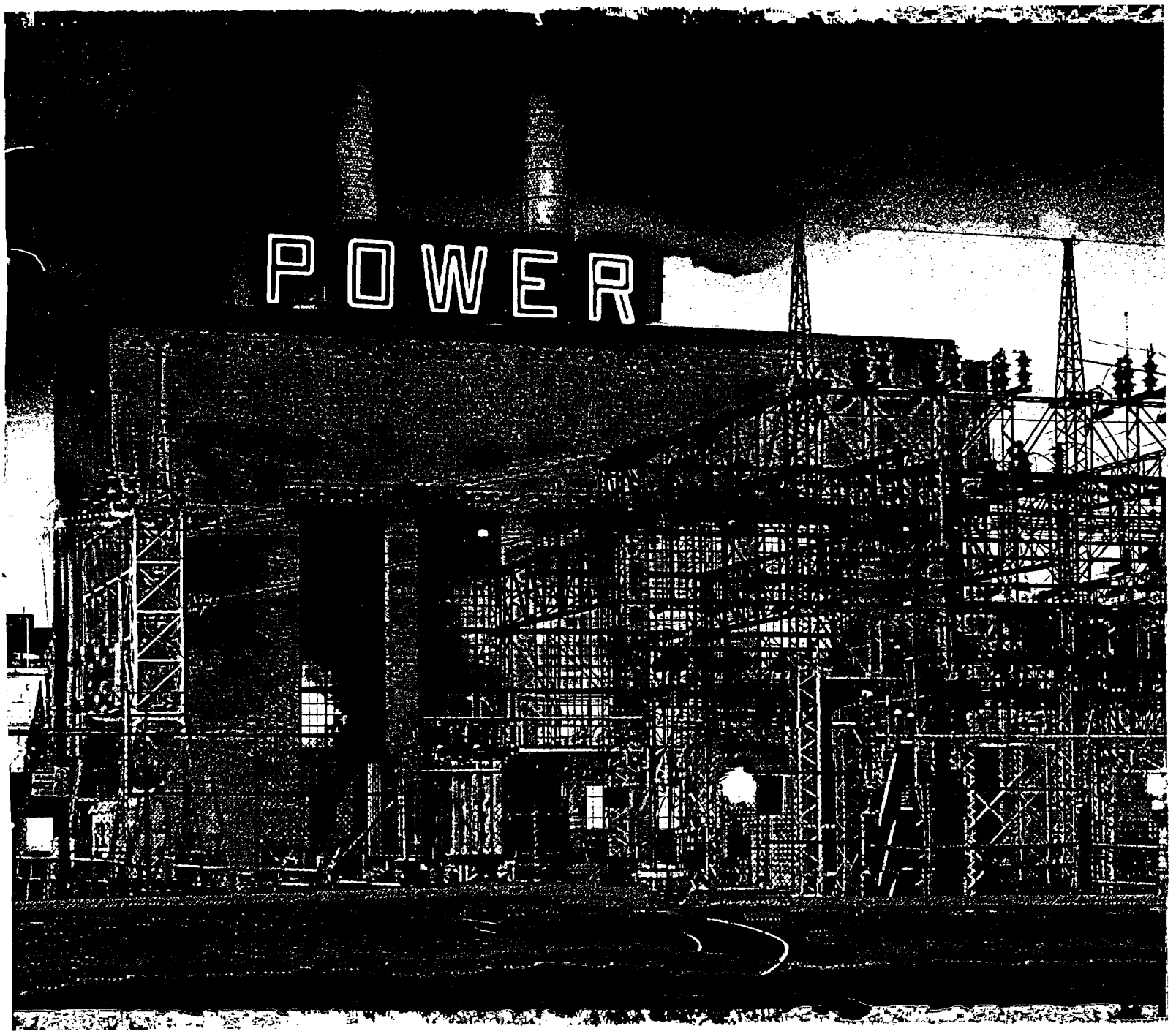
ENCLOSURE

PALO VERDE NUCLEAR GENERATING STATION

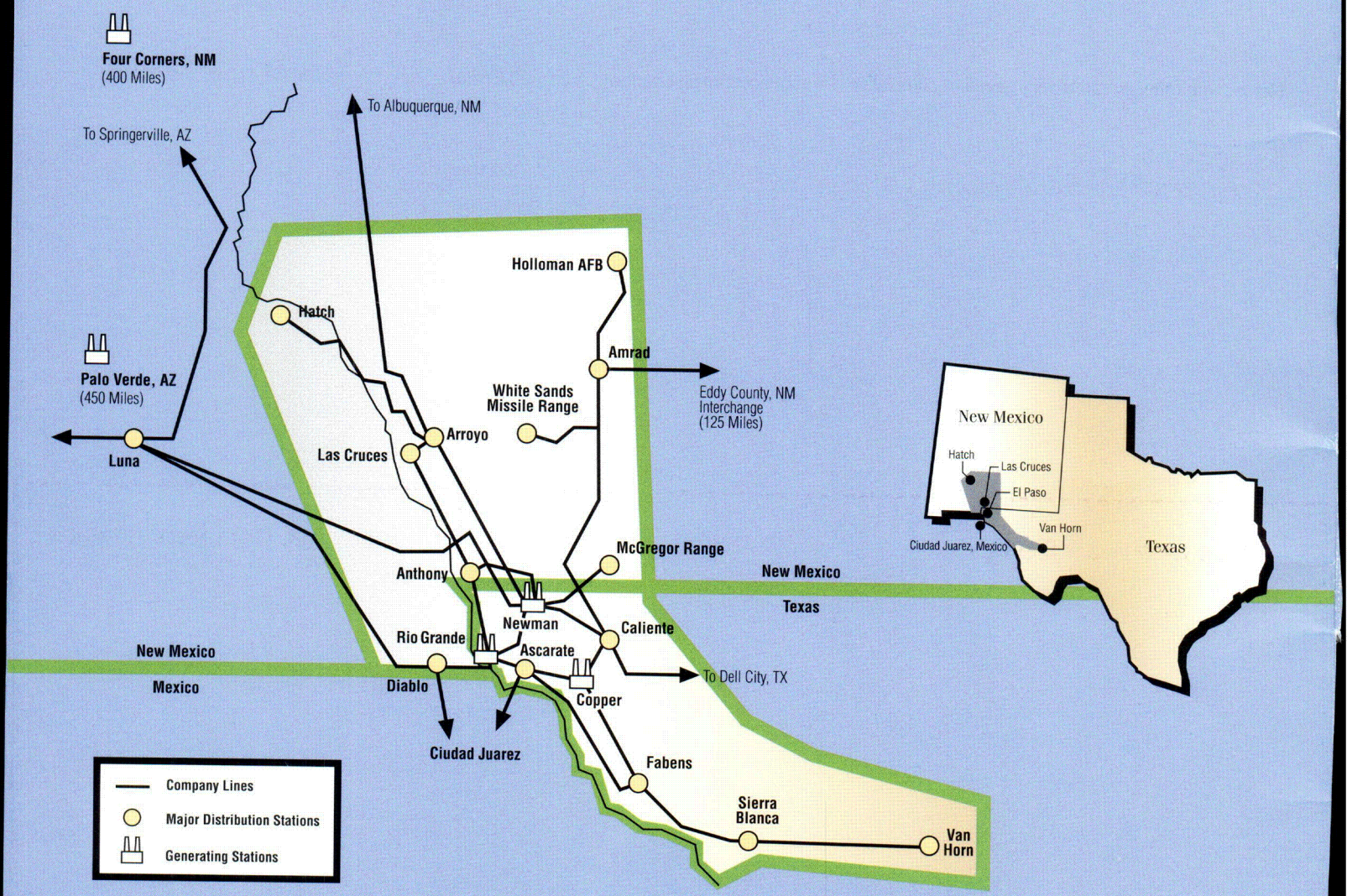
2004 ANNUAL FINANCIAL REPORTS



El Paso Electric

2004 Annual Report

SERVICE AREA



Statements in this document, other than statements of historical information, are forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements, as well as other oral and written forward-looking statements made by or on behalf of El Paso Electric (EPE) from time to time, including statements contained in EPE's filings with the Securities and Exchange Commission and its reports to shareholders, involve known and unknown risks and other factors which may cause EPE's actual results in future periods to differ materially from those expressed in any forward-looking statements. Please refer to EPE's 10-K for fiscal year ended December 31, 2004, and EPE's other 34 Act filings for a detailed discussion of these risks and uncertainties. EPE cautions that the risks and factors in such filings are not exclusive. EPE does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of EPE, except as required by law.

The company has filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 regarding the quality of our public disclosures as Exhibits 31.1 and 31.2 to our annual report on Form 10-K for the fiscal year ended December 31, 2004. In 2004 after our annual meeting of stockholders, the Company filed with the New York Stock Exchange the CEO certification regarding its compliance with the NYSE corporate governance listing standards as required by NYSE Rule 303A.12(a).

Cover photo, Rio Grande Power Plant

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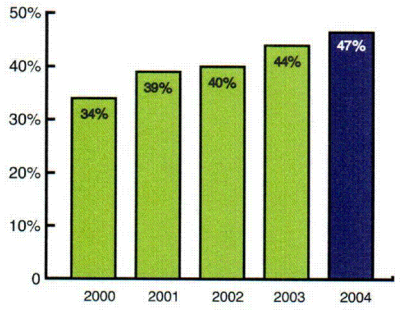
2004 PERFORMANCE HIGHLIGHTS

Financial ($000)	2002	2003	2004
Operating Revenues (net of energy expenses)	$ 459,847	$ 443,403	$ 447,753
Retail Base Revenues	$ 444,094	$ 453,323	$ 456,382
Economy Sales (net of fuel)	$ 5,455	$ 22,618	$ 21,265
Net Income (after extraordinary gain and cumulative effect of accounting change)	$ 28,674(a)	$ 59,957(b)	$ 35,171(c)
Total Assets	$1,648,229	$1,596,614	$1,581,355
Common Stock Data			
Earnings Per Share (diluted weighted average)	$ 0.57(a)	$ 1.23(b)	$ 0.73(c)
Market Price Per Share (year-end close)	$ 11.00	$ 13.35	$ 18.94
Book Value Per Share	$ 9.13	$ 10.42	$ 11.23
Weighted Average Number of Shares & Dilutive Potential Shares Outstanding	50,380,468	48,814,761	48,019,721
Number of Registered Holders	5,335	4,673	4,486

(a) 2002 information includes the effects of the FERC settlements of $9.5 million, net of tax or $0.19 diluted loss per share.
(b) 2003 information includes the one-time impact of the Customer Information System project impairment loss of $10.7 million net of tax, or $0.22 diluted loss per share. Also, included in 2003 net income and diluted earnings per share is a cumulative effect of an accounting change, net of tax, in the amount of $39.6 million or $0.81 per diluted share.
(c) 2004 information includes an extraordinary gain of $1.8 million, net of tax, or $0.04 per diluted share related to the re-application of SFAS No. 71 to EE's New Mexico jurisdictional operations and a $2.2 million, net of tax, charge for the 2004 employee annual bonus of $0.05 per diluted share.

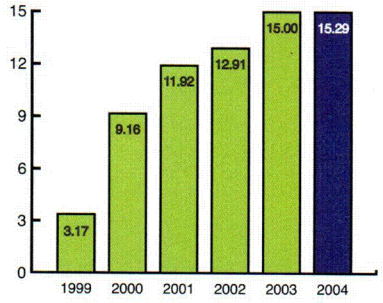
Common Stock Equity

(percent of capitalization)



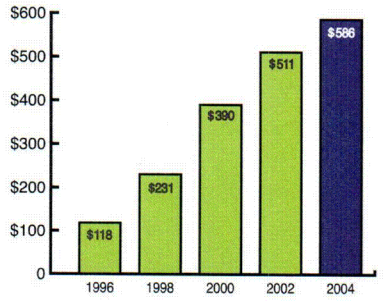
Cumulative Share Repurchases

(in millions)

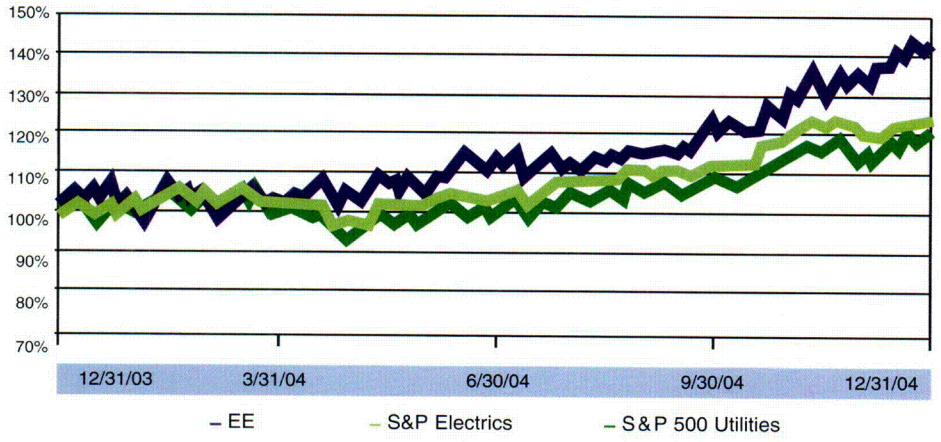


Cumulative Debt Repurchases and Redemptions

(in millions)

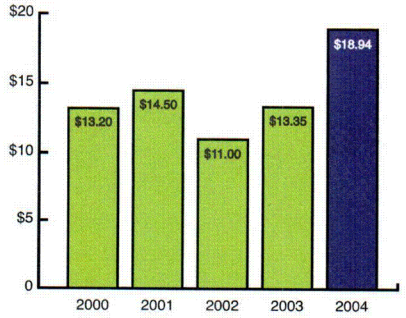


Relative Price Performance El Paso Electric vs. S & P Electric and S & P 500 Utilities Indices 12/31/03 - 12/31/04



Market Price Per Share

(year-end)



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physical symbol of El Paso Electric's long-time commitment to providing reliable and affordable electric energy to all its customers.

Perhaps the most significant regulatory event that occurred in 2004, which for the near term assures stability in EPE's service territory, was the ruling by the Public Utility Commission of Texas (PUCT) in October 2004 delaying by several years the implementation of retail competition in EPE's service territory. The newly adopted rule changed the beginning of retail competition from the date of the expiration of the current rate freeze, and instead set a schedule which identifies various milestones EPE must reach before competition can begin.

The first milestone calls for the development, approval by the Federal Energy Regulatory Commission, and commencement of independent operation of a regional transmission organization (RTO), including the development of retail market protocols to facilitate retail competition. The complete transition to retail competition will occur upon the completion of the last milestone which will be the PUCT's final evaluation of EPE's readiness to offer fair competition and reliable service to all retail customers.

EPE's current franchise and rate agreement with the City of El Paso expires in August of 2005. EPE is currently in discussions with the City regarding an extension of the franchise and possible renegotiation of a rate agreement.

Following the repeal of the New Mexico retail competition legislation in 2003, EPE and the New Mexico Public Regulatory Commission negotiated a rate settlement that freezes base rates in New Mexico from June 1, 2004 through May 31, 2007. The settlement, which took effect with new rates in June 2004, continues rate stability and operational certainty in our New Mexico service territory, where we have not had a litigated rate decision in more than 20 years.

El Paso Electric was recognized during 2004 for its success in providing reliable electric energy to its customers. This ongoing commitment to reliability is reflected in distribution system reliability measures established by the Public Utility Commission of Texas. These measures (which measure distribution system reliability), known as System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI), once again ranked El Paso Electric as the most reliable electric utility among major electric utilities in Texas. The outstanding results demonstrate that EPE's service quality has been and will continue to be one of its greatest operational assets.

2004 was another great year for El Paso Electric in the area of corporate citizenship and helping those in need. In fact, our employees not only assisted causes in our service territory, they also offered assistance to those who needed it thousands of miles away. On September 28, 2004, a caravan, which included 16 El Paso Electric employees and ten vehicles, departed El Paso for Florida to assist in the restoration of electricity in areas affected by hurricanes that battered the state. Crew members spent a total of eight days away from their families, battling hardships and severe conditions, assisting other electric utility personnel as they restored power to the area. As a result of this call to duty, our employees received many letters and notes of gratitude from both the companies they assisted as well as Florida residents.

Our 2004 financial, operational, and corporate citizenship achievements have strengthened our stability and are cornerstones to continuing to operate a strong, vertically integrated electric utility.

Within our service territory our employees continued their commitment to not only providing excellent service to customers, but also attending to the many needs of our communities. In 2004, EPE employees contributed more than 14,600 volunteer hours to their communities and donated more than 310 units of blood to our local United Blood Services agency. In addition, EPE employees pledged more than $160,400 to area United Way agencies. With the corporate contribution, EPE's total commitment to United Way was $240,668, making EPE the top corporate contributor to the United Way in El Paso. Our employees and EPE were also recognized by the American Heart Association for being the top corporate fundraiser, raising more than $44,000 for the association's 2004 Heart Walk.

El Paso Electric also continued to be an important contributor to the El Paso/Las Cruces economy. In 2004, $22.7 million or 25.6 percent of EPE's purchases of goods and services were spent in our service territory. Of these, 89.5 percent were purchases from small businesses, 40 percent were from minority-owned businesses and 9.1 percent were from women-owned businesses. We are proud of our commitment to supporting small businesses in our area.

El Paso Electric and its Board of Directors are committed to transparent disclosure policies and sound principles of corporate governance. Relentless pursuit of these standards is vitally important to earning and retaining the trust of our customers, employees and investors. We will continue to carefully monitor our operations and procedures so that they are in the strictest compliance with the letter and spirit of the Sarbanes-Oxley Act. Our corporate governance standards and polices can be found on our website at www.epelectric.com.

Our 2004 financial, operational, and corporate citizenship achievements have strengthened our stability and are cornerstones to continuing to operate a strong, vertically integrated electric utility. Our operational resources, as well as our human resources, provide the foundation for continuing to provide reliable and safe electric service to our customers and create value for you - our shareholders. Thank you for the confidence which is shown by your investment in El Paso Electric. Our commitment is to grow your investment with solid business strategies and results.

Gary R. Hedrick
President and Chief Executive Officer

George W. Edwards, Jr.
Chairman of the Board

BOARD OF DIRECTORS

George W. Edwards, Jr.
Chairman of the Board (a)
Retired in 1995. Prior to retirement, President, CEO and Director of Kansas City Southern Railway Company
Kansas City, MO

Gary R. Hedrick
President and CEO (b)
El Paso Electric
El Paso, TX

Stephen N. Wertheimer
Managing Director (c)
W Capital Partners
New York, NY

Patricia Z. Holland-Branch
CEO and Owner (d)
Facilities Connection, Inc.
El Paso, TX

Ramiro Guzmán
President (e)
Ramiro Guzmán & Associates
El Paso, TX

Kenneth R. Heitz
Partner (f)
Irell & Manella
Los Angeles, CA

OFFICERS

Gary R. Hedrick
President and Chief Executive Officer

J. Frank Bates
Executive Vice President, Chief Operations Officer

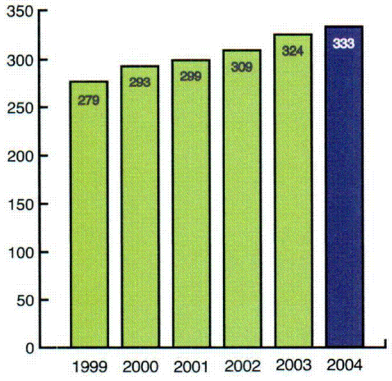
Raul A. Carrillo, Jr.
Senior Vice President, General Counsel and Corporate Secretary

Steven P. Busser
Vice President, Regulatory Affairs and Treasurer

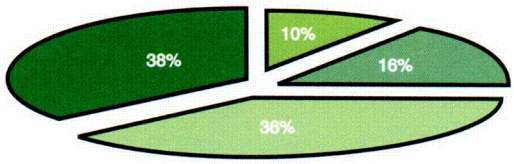
Fernando J. Gireud
Vice President, Power Marketing and International Business

2004 OPERATIONAL HIGHLIGHTS

Customers Served Per Employee

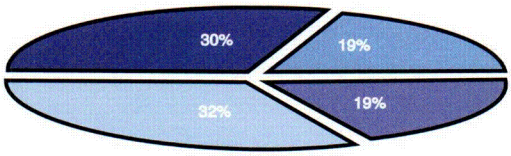


2004 Retail Base Operating Revenues



Residential...38%
Commercial & Ind. Large...10%
Public Authorities...16%
Commercial & Ind. Small...36%

2004 Retail MWh Sales



Residential...30%
Commercial & Ind. Large...19%
Public Authorities...19%
Commercial & Ind. Small...32%

C03

Dear Shareholders

2004 was truly an exceptional year for El Paso Electric. Our stock price rose to the highest levels in recent memory, and our cash flow remained strong, enabling us to retire $36 million in debt and repurchase an additional 294,842 shares of common stock. Both major credit rating agencies rewarded EPE with upgrades during the year, we continued to experience strong customer growth, we successfully resolved an Internal Revenue Service (IRS) dispute covering the treatment of a $688 million tax loss carry forward, and our regulators provided decisions that preserved value and established operational stability in our service territory.

EPE 's stock price outperformed the utility sector and the broader market during 2004 by delivering a one-year holding period return of 41.87 percent to shareholders, closing at a price of $18.94. In comparison, the Dow Jones Utility Index produced a total return of 30.24 percent while the S & P Electric Utility Total Return Index posted an increase of 26.48 percent. EPE has similarly outpaced utility and other relevant market indices for 3- and 5-year holding periods.

During the year, we continued to use our strong free cash flow to repurchase debt and stock, thereby improving our financial fundamentals, reducing financial risk, and enhancing the return to our shareholders. Since 1996, EPE has deployed approximately $902 million to repurchase debt, preferred and common stock, including approximately $36 million of debt repurchased in 2004, which decreased annual fixed charges by approximately $3.3 million. In 2004, EPE also repurchased 294,842 common shares of its new two-million-share repurchase program that was approved by the Board of Directors in February 2004. Since the initiation of our common share repurchase program in 1999, EPE has repurchased a total of 15.3 million shares at a total cost of approximately $175.6 million, including commissions.

As a result of EPE's aggressive debt reduction and conservative financial policies, EPE common stock equity represented 47 percent of our total capitalization at year-end 2004, slightly exceeding the industry average level of approximately 46 percent. EPE remains focused on strengthening its balance sheet, pursuing common stock repurchases when economically viable, and improving operating efficiency.

EPE's significant progress in improving its financial and operational profile was recently recognized by both Moody's and Standard and Poor's credit rating agencies. In August 2004, Standard and Poor's raised EPE's senior secured debt rating from BBB- to BBB and upgraded its unsecured debt rating to BBB-. In September 2004, Moody's increased EPE's senior secured debt rating from Baa3 to Baa2 and raised its unsecured debt rating to Baa3. EPE now enjoys an investment-grade rating on all of its outstanding corporate debt. EPE is extremely proud of these credit upgrades because they demonstrate our continuing commitment to conservative financial policies on behalf of our shareholders and reflect our employees' hard work and dedication to providing EPE customers with the highest quality service in the most efficient manner. These credit upgrades should enable EPE to lower its interest costs when we have the opportunity to refinance debt, and should contribute to the further improvement of our financial fundamentals. In August 2005, EPE will remarket approximately $193 million of Pollution Control Bonds, and in 2006 EPE has the opportunity to refinance its Series D and Series E First Mortgage Bonds, aggregating approximately $359 million.

In 2004, EPE reported basic earnings per share of $0.70 before the extraordinary gain related to the re-application of SFAS No. 71 in EPE's New Mexico jurisdictional operations. Earnings were affected by premiums paid on debt repurchases, a rise in pension and benefit costs, higher depreciation and amortization expenses, and increased Palo Verde operation and maintenance costs, in addition to several non-recurring items such as an IRS settlement and an increase to our coal reclamation liability. The impact of these items was partially offset by increased retail kWh sales growth and by a decline in non-Palo Verde maintenance expenses which resulted from our aggressive cost control efforts at our local generating plants.

EPE's core business remained strong in 2004, with our customer base expanding at a 2.5 percent annual rate. Every segment of our retail business exhibited growth during the year as a turnaround in our regional economy helped contribute to our retail kWh sales growth and partially offset the impact of significantly higher precipitation levels in the third quarter of the year. As a result of our increasing retail kWh sales and above-average customer growth, EPE attained a record native system peak of 1,332 MW in July 2004, which exceeded our previous record of 1,308 MW set in 2003.

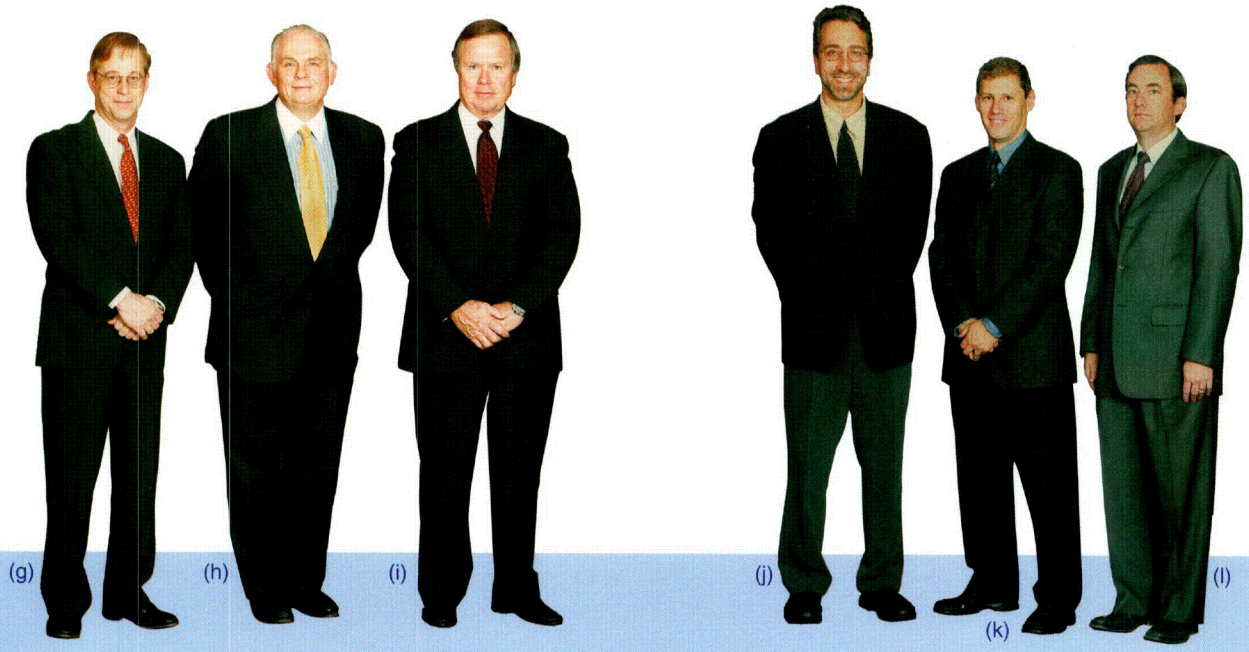
EPE experienced a strong year in economy sales despite reduced availability of certain resources due to outages. EPE had margins of $21.3 million during 2004 (before taxes and sharing with Texas customers). The 4.3 percent reduction in kWh sold was almost completely offset by higher average margins. In 2003, total margins before tax and sharing were $22.6 million.

Going forward, we will continue to actively pursue opportunities in the wholesale power market, but there is no guarantee that the improved conditions in the western wholesale power market will continue in the future, given the intrinsic volatility that exists in this market.

The Palo Verde Nuclear Generating Station continued to be ranked as the nation's largest power producer for the thirteenth consecutive year, with an output of 28.1 billion kWh. Palo Verde provided 49 percent of our energy in 2004. Replacement of the steam generator and low pressure turbine in Unit 2 was successfully completed in the fall of 2003 with Units 1 and 3 scheduled for replacement in the fall of 2005 and 2007, respectively. It is anticipated that these replacements will increase efficiency, extend unit lives, and improve the probability of license extensions.

In addition, to meet the anticipated future need for generation resources in our service territory, EPE entered into a 20-year agreement with Southwestern Public Service to purchase 133 MW beginning in 2006 assuring our customers of diversity in fuel source and access to a significant coal-based resource. We are currently evaluating the need for additional resources in the 2007 to 2009 timeframe.

2004 also marked the commemoration of the 75th anniversary of our Rio Grande Power Plant, which is still in operation today. In 1929, it took 600 workers only eight months to complete the original facility, which was considered record time for this type of construction. The plant stands as a



James W. Cicconi
General Counsel and Executive Vice President (g)
Law and Government Affairs, AT&T
Washington, D.C.

James W. Harris
Founder and President (h)
Seneca Financial Group, Inc.
Greenwich, CT

J. Robert Brown
President and Chairman of the Board (i)
Desert Eagle Distributing
El Paso, TX

Eric B. Siegel
Independent Investor and Business Consultant (j)
Retired Limited Partner of Apollo Advisors, LP
Los Angeles, CA

Michael K. Parks
Managing Director (k)
TCW Group
Los Angeles, CA

Charles A. Yamarone
Executive Vice President (l)
Libra Securities, LLC
Los Angeles, CA

Helen Knopp
Vice President, Public Affairs

Kerry B. Lore
Vice President, Administration

Robert C. McNiel
Vice President, New Mexico Affairs

Hector R. Puente
Vice President, Power Generation

Guillermo Silva, Jr.
Vice President, Information Services

John A. Whitacre
Vice President, Transmission and Distribution

Scott D. Wilson
Vice President, Corporate Planning and Controller

Operational	2002	2003	2004
Retail GWh Sold	6,322	6,450	6,581
% Change	1.67%	2.02%	2.03%
Native Peak (MW)	1,282	1,308	1,332
Customers at Year-End*	315,650	324,020	332,125
% Change	2.10%	2.65%	2.50%
Employees at Year-End	1,021	999	996

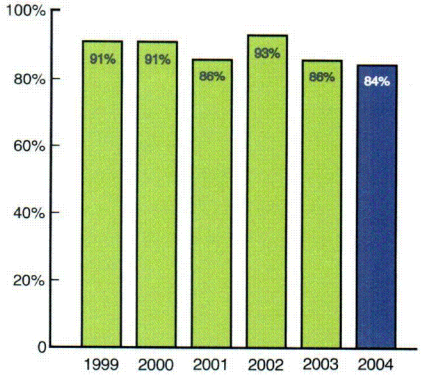
*Revised to conform with new 2004 commercial and industrial, large billing system which counts customers by service location rather than by meter. This change did not affect sales or revenues of the Company.

Generating Capacity

Plant	Entitlement	Fuel Source	Energy Mix
Palo Verde	600 MW	Nuclear	49%
Newman	482 MW	Natural Gas	27%
Rio Grande	246 MW	Natural Gas	
Copper	68 MW	Natural Gas	
Four Corners	104 MW	Coal	8%
		Purchased Power	16%
		Wind**	
TOTAL	**1,500 MW**		**100%**

** A 1.32 MW wind project began operating in April 2001.

Palo Verde Capacity Factor



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Operating Revenues (in thousands):	2004	2003	2002	2001
Base Revenues:				
Retail:				
Residential	$ 174,752	$ 171,459	$ 166,320	$ 159,263
Commercial and Industrial, Small	165,760	165,434	163,553	161,997
Commercial and Industrial, Large	43,150	43,294	43,419	43,644
Sales to Public Authorities	72,720	73,136	70,802	70,372
Total Retail	456,382	453,323	444,094	435,276
Wholesale:				
Sales for Resale	1,675	3,223	32,228	52,879
Total Base Revenues	458,057	456,546	476,322	488,155
Fuel Revenues	161,052	122,761	158,650	164,335
Economy Sales	78,533	76,536	43,654	92,452
Other	10,986	8,519	11,459	24,763
Total Operating Revenues	708,628	664,362	690,085	769,705
Number of Customers (end of year):				
Residential	296,435	289,179	281,874	276,200
Commercial and Industrial, Small	31,079	30,254	29,281	28,573
Commercial and Industrial, Large	58	63	64	65
Other	4,553	4,524	4,431	4,308
Total Customers	332,125	324,020	315,650	309,146
Energy Supplied, Net, MWh:				
Generated	7,611,465	7,740,923	7,785,938	8,183,713
Purchased and Interchanged	1,410,114	1,250,707	1,549,875	951,359
Total Energy Supplied	9,021,579	8,991,630	9,335,813	9,135,072
Energy Sales, MWh:				
Retail:				
Residential	1,986,085	1,932,171	1,870,931	1,789,199
Commercial and Industrial, Small	2,115,822	2,096,860	2,076,758	2,069,517
Commercial and Industrial, Large	1,236,426	1,197,065	1,161,815	1,174,235
Sales to Public Authorities	1,243,003	1,224,349	1,212,180	1,185,521
Total Retail	6,581,336	6,450,445	6,321,684	6,218,472
Wholesale:				
Sales for Resale	41,094	67,754	986,134	1,460,383
Economy Sales	1,838,467	1,920,882	1,483,465	929,914
Total Wholesale	1,879,561	1,988,636	2,469,599	2,390,297
Total Energy Sales	8,460,897	8,439,081	8,791,283	8,608,769
Losses and Company Use	560,682	552,549	544,530	526,303
Total, Net	9,021,579	8,991,630	9,335,813	9,135,072
Native System:				
Peak Load, MW	1,332	1,308	1,282	1,199
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500
Total System:				
Peak Load, MW	1,575	1,546	1,509	1,485
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500
System Capacity Factor	60.1%	60.1%	61.1%	60.6%

(a) Financial data is based on the results for the Predecessor Company for

2000	1999	1998	1997	1996(a)	1995
$ 157,341	$ 145,618	$ 150,151	$ 146,412	$ 141,718	$ 128,294
158,652	152,021	148,220	143,396	138,910	128,716
44,105	43,055	45,495	45,580	43,484	40,870
70,548	68,782	66,570	64,328	65,533	59,613
430,646	409,476	410,436	399,716	389,645	357,493
45,698	36,992	55,597	57,153	68,924	72,183
476,344	446,468	466,033	456,869	458,569	429,676
124,126	83,311	109,117	119,560	103,011	62,142
84,918	32,523	20,167	10,612	11,032	6,681
16,261	8,167	6,506	4,980	3,981	3,744
701,649	570,469	601,823	592,021	576,593	502,243
271,588	266,627	260,356	254,348	250,209	245,245
27,947	27,274	26,396	25,900	25,304	24,615
63	60	58	61	57	52
4,054	3,957	3,867	3,811	3,711	3,674
303,652	297,918	290,677	284,120	279,281	273,586
8,706,790	8,392,890	8,586,098	8,186,187	7,920,675	7,439,404
905,770	328,225	478,396	617,651	711,791	584,853
9,612,560	8,721,115	9,064,494	8,803,838	8,632,466	8,024,257
1,767,928	1,653,859	1,621,436	1,587,733	1,545,274	1,473,349
2,026,768	1,943,120	1,891,703	1,834,953	1,779,986	1,754,176
1,142,163	1,133,751	1,314,428	1,271,449	1,216,941	1,121,329
1,177,883	1,135,438	1,120,654	1,090,312	1,110,706	1,068,048
6,114,742	5,866,168	5,948,221	5,784,447	5,652,907	5,416,902
1,282,540	905,975	1,757,880	1,897,885	1,753,553	1,646,357
1,714,288	1,497,880	888,708	640,017	757,999	538,102
2,996,828	2,403,855	2,646,588	2,537,902	2,511,552	2,184,459
9,111,570	8,270,023	8,594,809	8,322,349	8,164,459	7,601,361
500,990	451,092	469,685	481,489	468,007	422,896
9,612,560	8,721,115	9,064,494	8,803,838	8,632,466	8,024,257
1,159	1,159	1,167	1,122	1,105	1,088
1,500	1,500	1,500	1,500	1,500	1,500
1,427	1,307	1,464	1,442	1,387	1,374
1,500	1,500	1,500	1,500	1,500	1,500
66.0%	61.2%	61.9%	60.5%	57.2%	55.3%

periods prior to February 11, 1996 and the Reorganized Company thereafter.

RIO GRANDE POWER STATION FACTS

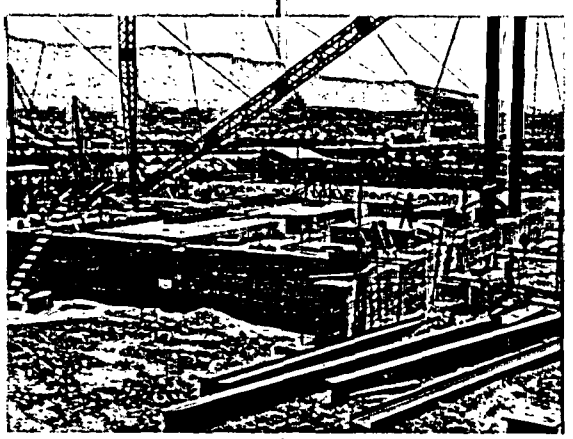
- Construction on the power station began in March 1929 and was completed in a record-setting 8 months in November 1929.

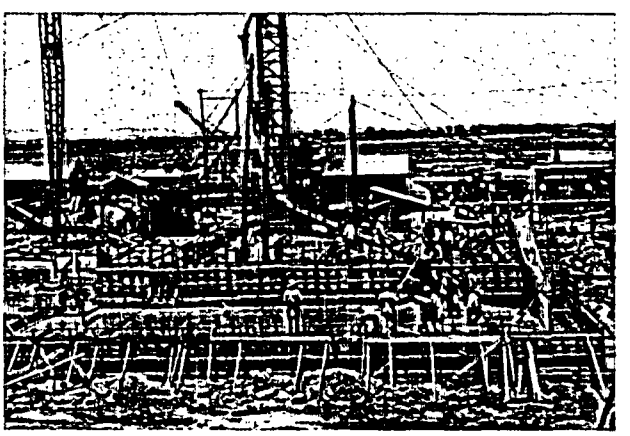
- An average of 600 workers were employed during construction and were under the supervision of Mr. R.G. Taber.

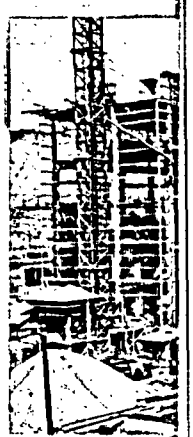
- The power station building, equipment, feeder lines and substations cost $5 million to build in 1929.

- The power station was built in what was then called El Paso's upper valley, now Sunland Park, New Mexico. The name was befitting of the location of its construction since the plant was built on the border of the Rio Grande River on what had been thought to be the Texas side. As a result of a meandering river and eventual legislation in the United States Congress, El Paso Electric's property where the power station is sited was deeded to New Mexico.

- More than 200 citizens of El Paso, Juarez and the valleys were guests of El Paso Electric at a dinner on November 26, 1929 when the Rio Grande Power Station was placed in operation for the first time. The Honorable R.E. Thomason, Mayor of El Paso, pressed the button that placed the facilities of the new power station at the service of the people in this community. Dinner was served in the giant turbine room.







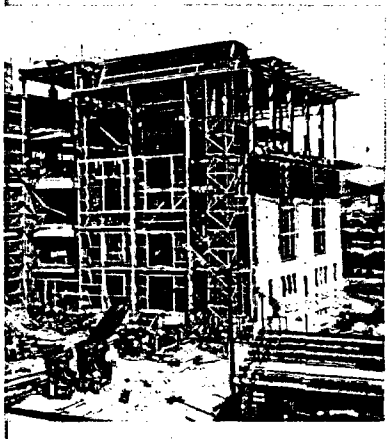
1929 – Units 1 & 2: 19 and 25 MW, General Electric and Westinghouse Turbine-Generators

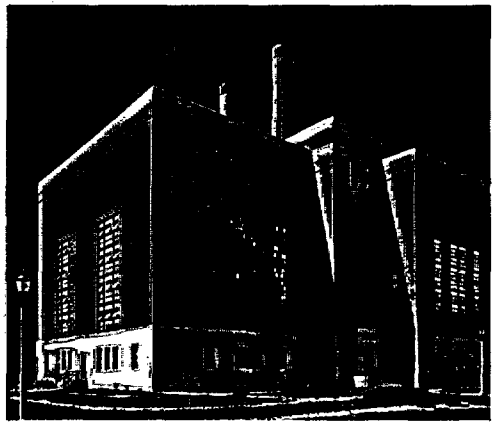
1941 – Unit 3: 20 MW, General Electric Turbine-Generator

1948 – Unit 4: 36 MW, Westinghouse Turbine-Generator

1953 – Unit 5: 34 MW, General Electric Turbine-Generator

- In 1941, auxiliary boiler 1B was added to meet the steam requirements of units 1, 2, and 3.
- On January 1, 1950, addition of the front office building was completed.
- The power station's cooling water medium was converted from direct intake from the canal to well water systems and cooling towers in 1953.
- The method of producing distilled water was changed from Evaporators to a Reverse Osmosis System in 1981.
- The power station has expanded to include eight generating units.
- Today, only units 6, 7, and 8 are operational. The other units were retired in 1988. The units operate primarily on natural gas, but can also operate on fuel oil.
- The Rio Grande Power Station has the capacity to generate 246 MW of electricity.





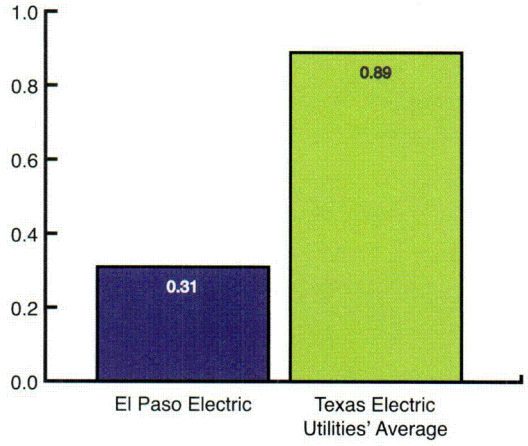
1957 – Unit 6: 50 MW, Westinghouse Turbine-Generator

1958 – Unit 7: 50 MW, General Electric Turbine-Generator

1972 – Unit 8: 150 MW, Westinghouse Turbine-Generator

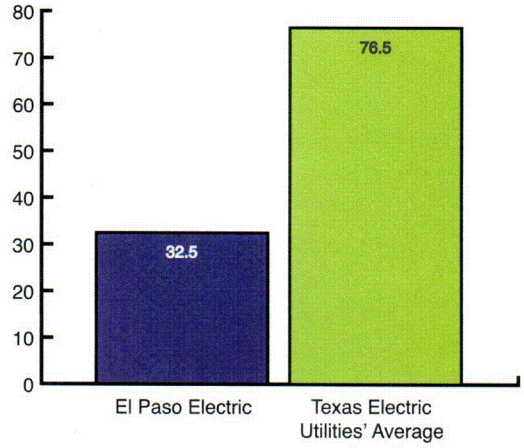
DISTRIBUTION

System Average Interruption Frequency Index - SAIFI



SAIFI - the average number of sustained interruptions (5 minutes or more) that each customer on the system could expect to experience over a one-year period. On average, EPE customers could have expected 0.31 interruptions over one year.

System Average Interruption Duration Index - SAIDI



SAIDI - the average duration of sustained interruptions (5 minutes or more) that each customer on the system could expect to experience over a one-year period. As a complement to SAIFI, customers on EPE's system could expect 0.31 interruptions over one year, and that interruption would last 32.5 minutes.

INVESTOR RELATIONS

Securities and Records

The common stock of El Paso Electric is traded on the New York Stock Exchange. The ticker symbol is EE.
EPE and The Bank of New York (BONY) act as co-registrars for EPE's common stock. BONY maintains all shareholder records of EPE.

Form 10-K Report and Shareholder Inquiries

A complete copy of EPE's Annual Report and Form 10-K for the year ended December 31, 2004, which has been filed with the Securities and Exchange Commission, including financial statements and financial statement schedules, is available without charge upon written request to:

Investor Relations

El Paso Electric
P.O. Box 982
El Paso, TX 79960
Or call: (800) 592-1634
E-mail: investor_relations@epelectric.com • Website: http://www.epelectric.com

Shareholder Services

Shareholders may obtain information relating to their share position, transfer requirements, lost certificates, and other related matters by contacting BONY Shareholder Services at (800) 524-4458. This service is available to all shareholders Monday through Friday, 8 a.m. to 8 p.m., EST.

SHAREHOLDERS

Address Shareholder Inquiries to:

The Bank of New York
Shareholder Relations
Church Street Station
P.O. Box 11258
New York, NY 10286-1258
Website: http://www.stockbny.com

Annual Meeting of Shareholders

The annual meeting of El Paso Electric's shareholders will be held at 10 a.m., Mountain Daylight Time on Wednesday, May 4, 2005 at the Stanton Tower Building, 100 N. Stanton, El Paso, TX 79901. In connection with the meeting, proxies will be solicited by the Board of Directors of EPE. A notice of meeting, together with a proxy statement, a form of proxy, and the Annual Report to Shareholders for 2004, were mailed on or about March 31, 2005 to shareholders of record as of March 7, 2005.

Send Certificates for Transfer and Address Changes to:

The Bank of New York
Receive and Deliver Dept.
Church Street Station
P.O. Box 11002
New York, NY 10286-1002

C05

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

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 0-296

El Paso Electric Company

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	74-0607870 (I.R.S. Employer Identification No.)
Stanton Tower, 100 North Stanton, El Paso, Texas (Address of principal executive offices)	79901 (Zip Code)

Registrant's telephone number, including area code: (915) 543-5711

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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 by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). YES _X_ NO ___

As of June 30, 2004, the aggregate market value of the voting stock held by non-affiliates of the registrant was $725,531,699 (based on the closing price as quoted on the New York Stock Exchange on that date).

As of February 28, 2005, there were 47,496,148 shares of the Company's no par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the 2005 annual meeting of its shareholders are incorporated by reference into Part III of this report.

DEFINITIONS

The following abbreviations, acronyms or defined terms used in this report are defined below:

Abbreviations, Acronyms or Defined Terms	Terms
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
CFE	Comisión Federal de Electricidad de Mexico, the national electric utility of Mexico
Common Plant or Common Facilities	Facilities at or related to Palo Verde that are common to all three Palo Verde units
Company	El Paso Electric Company
DOE	United States Department of Energy
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Four Corners	Four Corners Generating Station
Freeze Period	Ten-year period beginning August 2, 1995, during which base rates for most Texas retail customers are expected to remain frozen pursuant to the Texas Rate Stipulation
IID	Imperial Irrigation District, an irrigation district in southern California
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
Las Cruces	City of Las Cruces, New Mexico
MiraSol	MiraSol Energy Services, Inc., a wholly-owned subsidiary of the Company
MW	Megawatt(s)
MWh	Megawatt-hour(s)
New Mexico Commission	New Mexico Public Regulation Commission
New Mexico Restructuring Act	New Mexico Electric Utility Industry Restructuring Act of 1999
New Mexico Stipulation	Stipulation and Settlement Agreement in Case No. 03-00302-UT dated April 27, 2004 between the Company and all other parties to the Company's rate proceedings before the New Mexico Commission providing for, among other things, a three-year freeze on base rates after an initial 1% reduction
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
PNM	Public Service Company of New Mexico
SFAS	Statement of Financial Accounting Standards
SPS	Southwestern Public Service Company
TEP	Tucson Electric Power Company
Texas Commission	Public Utility Commission of Texas
Texas Fuel Settlement	Settlement Agreement in Texas Docket No. 23530 dated November 1, 2001, between the Company, the City of El Paso and various parties whereby the Company increased its fuel factors, implemented a fuel surcharge and revised its Palo Verde Nuclear Generating Station performance standards calculation
Texas Rate Stipulation	Stipulation and Settlement Agreement in Texas Docket No. 12700 dated August 30, 1995, between the Company, the City of El Paso, the Texas Office of Public Utility Counsel and most other parties to the Company's rate proceedings before the Texas Commission providing for a ten-year rate freeze and other matters
Texas Restructuring Law	Texas Public Utility Regulatory Act Chapter 39, Restructuring of the Texas Electric Utility Industry
Texas Settlement Agreement	Settlement Agreement in Texas Docket No. 20450 dated March 25, 1999, between the Company, the City of El Paso and various parties providing for a reduction of the Company's jurisdictional base revenue and other matters
TNP	Texas-New Mexico Power Company

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K other than statements of historical information are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like the Company "believes", "anticipates", "targets", "expects", "pro forma", "estimates", "intends" and words of similar meaning. Forward-looking statements describe the Company's future plans, objectives, expectations or goals. Such statements address future events and conditions concerning:

- capital expenditures,
- earnings,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- nuclear operations, and
- the overall economy of the Company's service area.

These forward-looking statements involve known and unknown risks that may cause the Company's actual results in future periods to differ materially from those expressed in any forward-looking statement. Factors that would cause or contribute to such differences include, but are not limited to, such things as:

- the Company's rates following the end of the Freeze Period and the New Mexico Stipulation,
- loss of margins on off-system sales,
- increased costs at Palo Verde,
- unscheduled outages,
- electric utility deregulation or re-regulation,
- regulated and competitive markets,
- ongoing municipal, state and federal activities,
- economic and capital market conditions,
- changes in accounting requirements and other accounting matters,
- changing weather trends,
- rates, cost recoveries and other regulatory matters,
- the impact of changes and downturns in the energy industry and the market for trading wholesale electricity,
- political, legislative, judicial and regulatory developments,
- the impact of lawsuits filed against the Company,
- the impact of changes in interest rates,
- inability to refinance maturing debt,

- changes in, and the assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets,
- the impact of changing cost and cost escalation and other assumptions on the Company's nuclear decommissioning liability for the Palo Verde Nuclear Generating Station,
- Texas, New Mexico and electric industry utility service reliability standards,
- homeland security considerations,
- coal, natural gas, oil and wholesale electricity prices, and
- other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. A discussion of some of these factors is included in this document under the headings "Risk Factors" and "Management's Discussion and Analysis" "–Summary of Critical Accounting Policies and Estimates" and "–Liquidity and Capital Resources." This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and the Company is not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

PART I

Item 1. Business

General

El Paso Electric Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves a wholesale customer in Texas and periodically in the Republic of Mexico. The Company owns or has significant ownership interests in six electrical generating facilities providing it with a total capacity of approximately 1,500 MW. For the year ended December 31, 2004, the Company's energy sources consisted of approximately 49% nuclear fuel, 27% natural gas, 8% coal, 16% purchased power and less than 1% generated by wind turbines.

The Company serves approximately 332,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico (representing approximately 59% and 9%, respectively, of the Company's operating revenues for the year ended December 31, 2004). In addition, the Company's wholesale sales include sales for resale to other electric utilities and periodically sales to the CFE and power marketers. Principal industrial and other large customers of the Company include steel production, copper and oil refining, and United States military installations, including the United States Army Air Defense Center at Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico.

The Company's principal offices are located at the Stanton Tower, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of February 28, 2005, the Company had approximately 1,000 employees, 33% of whom are covered by a collective bargaining agreement. A new collective bargaining agreement, which expires June 2006, was entered into with these employees in July 2003. In addition, the Company is presently conducting collective bargaining negotiations with an additional 138 employees from the Company's meter reading and collections area, facilities services area and customer service area who voted for union representation in 2003 and 2004.

The Company makes available free of charge through its website, www.epelectric.com, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission ("SEC"). In addition, copies of the annual report will be made available free of charge upon written request. The SEC also maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. The address of that site is www.sec.gov.

Facilities

The Company's net installed generating capacity of approximately 1,500 MW consists of approximately 600 MW from Palo Verde Units 1, 2 and 3, 482 MW from its Newman Power Station, 246 MW from its Rio Grande Power Station, 104 MW from Four Corners Units 4 and 5, 68 MW from its Copper Power Station and 1.32 MW from Hueco Mountain Wind Ranch.

Palo Verde Station

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company ("SCE"), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde.

The NRC has granted facility operating licenses and full power operating licenses for Palo Verde Units 1, 2 and 3, which expire in 2024, 2025 and 2027, respectively. In addition, the Company is separately licensed by the NRC to own its proportionate share of Palo Verde.

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company's decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS.

In accordance with the ANPP Participation Agreement, the Company is required to establish a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company remained above its minimum funding level as of December 31, 2004. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

In August 2002, the Palo Verde Participants approved the 2001 Palo Verde decommissioning study. Some changes in the cost calculations occurred between the prior 1998 study and the 2001 study. The 2001 study estimated that the Company must fund approximately $311.6 million (stated in 2001 dollars) to cover its share of decommissioning costs. The previous cost estimate from the 1998 study estimated that the Company needed to fund approximately $280.5 million (stated in 1998 dollars). The 2001 estimate reflects an 11.1% increase, or 3.6% average annual compound increase, from the 1998 estimate primarily due to increases in estimated costs for site restoration at each unit, pre and post-shutdown transitioning and decommissioning preparations, spent fuel storage after operations have ceased and the Unit 2 steam generator storage. The decommissioning study is stated in 2001 dollars and makes no inflation assumptions. See "Spent Fuel Storage" below.

Although the 2001 study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject

to significant uncertainty. The decommissioning study is updated every three years. The 2004 study is expected to be complete in the second quarter of 2005. See "Disposal of Low-Level Radioactive Waste" below.

Historically, regulated utilities such as the Company have been permitted to collect in rates the costs of nuclear decommissioning. The Company, through an affiliated transmission and distribution utility, will be able to continue to collect from customers the costs of decommissioning if and when it becomes subject to the Texas Restructuring Law. The collection mechanism utilized in Texas is a "non-bypassable wires charge" through which all customers, even those who choose to purchase energy from a supplier other than the Company's retail affiliate, will be required to pay a fee, which includes the cost of nuclear decommissioning, to the Company's affiliated transmission and distribution utility. In the Company's case, collection of the fee through the Company's transmission and distribution utility will begin in Texas if and when retail competition is implemented in the Company's Texas service territory. See "Regulation – Texas Regulatory Matters – Deregulation" for further discussion.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which are stored at the new facilities until it is accepted by the DOE for permanent disposal. The 2001 decommissioning study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2037. APS believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation until 2010. Subsequent judicial decisions required the DOE to start accepting spent nuclear fuel by January 31, 1998. The DOE did not meet that deadline, and the Company cannot currently predict when spent fuel shipments to the DOE's permanent disposal site will commence.

The Company expects to incur significant on-site spent fuel storage costs during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs will be amortized over the burn period of the fuel that will necessitate the use of the alternative on-site storage facilities until an agreement is reached with the DOE for recovery of these costs. In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. The Company is unable to predict the outcome of these matters at this time.

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the

California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Palo Verde is projected to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact. The opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

Steam Generators. Palo Verde has experienced degradation in the steam generator tubes of each unit. The projected service lives of the Palo Verde steam generators are reassessed by APS periodically in conjunction with inspections made during scheduled outages at the Palo Verde units. New steam generators were installed at Unit 2 during 2003 at a total cost to the Company of approximately $45.4 million. This replacement was based on an analysis of the net economic benefit from expected improved performance of the unit and the need to realize continued production from that unit over its full licensed life.

APS has identified accelerated degradation in the steam generator tubes in Units 1 and 3 and has concluded that it is economically desirable to replace the steam generators at those units. The eventual total project cash expenditures for steam generator replacements for Units 1, 2 and 3 are currently estimated to be $724.0 million excluding replacement power costs (the Company's portion being $114.4 million). As of December 31, 2004, the Company has paid approximately $59.0 million of such costs. The remaining balance is expected to be paid over the course of the steam generator replacements. The Company expects its portion will be funded with internally generated cash.

The Texas Rate Stipulation precludes the Company from seeking a rate increase to recover additional capital costs incurred at Palo Verde during the Freeze Period. The Company cannot assure that its wholesale power rates and its competitive retail rates will be sufficient to recover its costs when or if retail competition for generation services begins. See also Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview."

Liability and Insurance Matters. In 1957, Congress enacted the Price-Anderson Act as an amendment to the Atomic Energy Act of 1954 to provide a system of financial protection for persons who may be injured or persons who may be liable for a nuclear incident. The Price-Anderson Act expired on December 31, 2003. Existing licensees, such as the Company, are grandfathered and will continue to be subject to the provisions of the Price-Anderson Act in the event Congress does not reauthorize the Price-Anderson Act. Despite extensive debate, the 108th Congress adjourned without passing comprehensive energy legislation which would have extended the Price-Anderson Act. While introduction of energy legislation in the 109th Congress is pending, it remains unclear what its course may be. Proposals to separate less controversial provisions such as the reauthorization of the Price-Anderson Act from the comprehensive legislation were resisted by the House and Senate leadership.

Current versions of energy omnibus legislation, if passed, would provide for the reauthorization of the Price-Anderson Act, thus amending the Atomic Energy Act to: (i) increase from $63 million to $95.8 million the maximum amount of standard deferred premiums charged a licensee following any nuclear incident under an industry retrospective rating plan and (ii) increase from $10 million to $15 million (adjusted for inflation) in any one year the maximum amount of such premiums for each

facility for which the licensee must maintain the maximum amount of primary financial protection. The aggregate amount of DOE indemnification currently available to all licensees under the Price-Anderson Act is $9.4 billion. Additionally, the Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability under the Price-Anderson Act. The insurance consists of $200 million of primary liability insurance provided by commercial insurance carriers, with the balance being provided by an industry-wide retrospective assessment program, pursuant to which industry participants would be required to pay a retrospective assessment to cover any loss in excess of $200 million. Presently, the maximum retrospective assessment per reactor for each nuclear incident is approximately $88.1 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential retrospective assessment per incident is approximately $41.8 million for all three units with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company also has obtained insurance against a portion of any increased cost of generation or purchased power which may result from an accidental outage of any of the three Palo Verde units if the outage exceeds 12 weeks.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of three steam-electric generating units and one combined cycle generating unit with an aggregate capacity of approximately 482 MW. The units operate primarily on natural gas but can also operate on fuel oil.

Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate capacity of approximately 246 MW. The units operate primarily on natural gas but can also operate on fuel oil.

Four Corners Station

The Company owns a 7% interest, or approximately 104 MW, in Units 4 and 5 at Four Corners, located in northwestern New Mexico. Each of the two coal-fired generating units has a total generating capacity of 739 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants, PNM, TEP, SCE and SRP.

Four Corners is located on land held on easements from the federal government and a lease from the Navajo Nation that expires in 2016, with a one-time option to extend the term for an additional 25 years. Certain of the facilities associated with Four Corners, including transmission lines and almost all of the contracted coal sources, are also located on Navajo land. Units 4 and 5 are located adjacent to a surface-mined supply of coal.

Copper Power Station

The Company's Copper Power Station, located in El Paso, Texas, consists of a 68 MW combustion turbine used primarily to meet peak demands. The unit operates primarily on natural gas but can also operate on fuel oil. The Company leased the combustion turbine until December 2003 at which time the Company purchased the facilities.

Hueco Mountain Wind Ranch

The Company's Hueco Mountain Wind Ranch, located in Hudspeth County, east of El Paso County and adjacent to Horizon City, currently consists of two wind turbines with a total capacity of 1.32 MW.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four major 345 kV transmission lines in New Mexico, three 500 kV lines in Arizona, and owns the transmission and distribution network within its New Mexico and Texas retail service area and operates these facilities under franchise agreements with various municipalities. The Company is also a party to various transmission and power exchange agreements that, together with its owned transmission lines, enable the Company to deliver its energy entitlements from its remote generation sources at Palo Verde and Four Corners to its service area. Pursuant to standards established by the North American Electric Reliability Council and the Western Electricity Coordinating Council, the Company operates its transmission system in a way that allows it to maintain system integrity in the event that any one of these transmission lines is out of service.

Springerville-Diablo Line. The Company wholly owns a 310-mile, 345 kV transmission line from TEP's Springerville Generating Plant near Springerville, Arizona, to the Luna Substation near Deming, New Mexico, and to the Diablo Substation near Sunland Park, New Mexico. This transmission line provides an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners.

Arroyo-West Mesa Line. The Company wholly owns a 202-mile, 345 kV transmission line from the Arroyo Substation located near Las Cruces, New Mexico, to PNM's West Mesa Substation located near Albuquerque, New Mexico. This is the primary delivery point for the Company's generation entitlement from Four Corners, which is transmitted to the West Mesa Substation over approximately 150 miles of transmission lines owned by PNM.

Greenlee-Newman Line. The Company owns 40% of a 60-mile, 345 kV transmission line between TEP's Greenlee Substation near Duncan, Arizona to the Hidalgo Substation near Lordsburg, New Mexico, approximately 57% of a 50-mile, 345 kV transmission line between the Hidalgo Substation and the Luna Substation and 100% of an 86-mile, 345 kV transmission line between the Luna Substation and the Newman Power Station. These lines provide an interconnection with TEP for delivery of the Company's entitlements from Palo Verde and, if necessary, Four Corners. The Company owns the Afton 345 kV Substation located approximately 57 miles from the Luna Substation on the Luna-to-Newman portion of the line which interconnects a generator owned and operated by PNM.

AMRAD-Eddy County Line. The Company owns 66.7% of a 125-mile, 345 kV transmission line from the AMRAD Substation near Oro Grande, New Mexico, to the Company's and TNP's high voltage direct current terminal at the Eddy County Substation near Artesia, New Mexico. The Company owns 66.7% of the terminal. This terminal enables the Company to connect its transmission system to that of SPS, providing the Company with access to purchased and emergency power from SPS and power markets to the east.

Palo Verde Transmission and Switchyard. The Company owns 18.7% of two 45-mile, 500 kV lines from Palo Verde to the Westwing Substation located northwest of Phoenix near Peoria, Arizona and 18.7% of a 75-mile, 500 kV line from Palo Verde to the Kyrene Substation located near Tempe, Arizona. These lines provide the Company with a transmission path for delivery of power from Palo Verde. The Company also owns 18.7% of two 500 kV switchyards connected to the Palo Verde-Kyrene 500 kV line: the Hassayampa switchyard adjacent to the southern edge of the Palo Verde 500 kV switchyard and the Jojoba switchyard approximately 24 miles from Palo Verde. These switchyards were built to accommodate the addition of new generation and transmission in the Palo Verde area.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state, tribal and local authorities. Those authorities govern current facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these environmental regulatory requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil, and/or criminal penalties. If the United States regulates green house gas emissions, the Company's fossil fuel generation assets will be faced with the additional cost of monitoring, controlling and reporting these emissions. In addition, unauthorized releases of pollutants or contaminants into the environment can result in costly cleanup obligations that are subject to enforcement by the regulatory agencies. Environmental regulations can change rapidly and are often difficult to predict. While the Company strives to prepare for and implement changes necessary to comply with changing environmental regulations, substantial expenditures may be required for the Company to comply with such regulations in the future.

The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis and believes it has made adequate provision in its financial statements to meet such obligations. As a result of this analysis, the Company has a provision for environmental remediation obligations of approximately $1.3 million as of December 31, 2004, which is related to compliance with federal and state environmental standards. However, unforeseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company.

Along with many other companies, the Company received from the Texas Commission on Environmental Quality ("TCEQ") a request for information dated October 15, 2003 in connection with environmental conditions at a facility in San Angelo, Texas that has been owned and operated by the San Angelo Electric Service Company ("SESCO"). The Company's written response to TCEQ notes that SESCO performed repair services for certain Company electrical equipment between 1981 and 1991, prior to the Company's bankruptcy. Although the SESCO site has not been designated as a state or federal Superfund site and the Company has not been named as a "responsible party" or a "potentially responsible party" at that site, the Company received in October 2004 an invitation to participate in site cleanup activities from a group of private companies that are conducting certain cleanup activities at the SESCO site. At this time, the Company has not agreed to participate in the cleanup of the SESCO site

and is unable to predict the outcome of this matter, although the Company has no reason at present to believe that it will incur material liabilities in connection with the SESCO site.

Except as described herein, the Company is not aware of any other active investigation of its compliance with environmental requirements by the Environmental Protection Agency, the TCEQ or the New Mexico Environment Department which is expected to result in any material liability. Furthermore, except as described herein, the Company is not aware of any unresolved, potentially material liability it would face pursuant to the Comprehensive Environmental Response, Comprehensive Liability Act of 1980, also known as the Superfund law.

Construction Program

Utility construction expenditures reflected in the following table consist primarily of local generation (including cost of capacity to replace units to be retired), expanding and updating the transmission and distribution systems and the cost of capital improvements and replacements at Palo Verde, including the fabrication and installation of Palo Verde Units 1 and 3 steam generators. Replacement power costs expected to be incurred during the replacement of Palo Verde steam generators are not included in construction costs. Studies indicate that the Company will need additional supply-side and demand-side resources to meet increasing load requirements on its system. As a result, the Company is currently evaluating various alternatives to meet its load requirements, but those costs are not included in the table.

The Company's estimated cash construction costs for 2005 through 2008 are approximately $498 million. Actual costs may vary from the construction program estimates shown. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1)(2) (In millions)		By Function (In millions)	
2005	$ 95	Production (1)(2)	$ 284
2006	83	Transmission	32
2007	141	Distribution	126
2008	179	General	56
Total	$ 498	Total	$ 498

(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources – Nuclear Fuel."

(2) Includes $159.6 million for local generation, $15.4 million for the Four Corners Station and $109.4 million for the Palo Verde Station.

Energy Sources

General

The following table summarizes the percentage contribution of nuclear fuel, natural gas, coal and purchased power to the total kWh energy mix of the Company. Energy generated by wind turbines accounted for less than 1% of the total kWh energy mix.

Power Source	Years Ended December 31, 2004	2003	2002
Nuclear fuel	49%	50%	52%
Natural gas	27	27	25
Coal	8	9	6
Purchased power	16	14	17
Total	100%	100%	100%

Allocated fuel and purchased power costs are generally passed through directly to customers in Texas and New Mexico pursuant to applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the Texas and New Mexico Commissions to determine whether a refund or surcharge based on such historical costs and revenues is necessary. See "Regulation – Texas Regulatory Matters" and "– New Mexico Regulatory Matters."

Nuclear Fuel

The nuclear fuel cycle for Palo Verde consists of the following stages: the mining and milling of uranium ore to produce uranium concentrates; the conversion of the uranium concentrates to uranium hexafluoride ("conversion services"); the enrichment of uranium hexafluoride ("enrichment services"); the fabrication of fuel assemblies ("fabrication services"); the utilization of the fuel assemblies in the reactors; and the storage and disposal of the spent fuel. The Palo Verde Participants have contracts in place that will furnish 100% of Palo Verde's operational requirements for uranium concentrates, conversion services and enrichment services through 2008. Such contracts could also provide 100% of enrichment services in 2009 and 2010. The Palo Verde Participants have a contract for fabrication services through 2016 for each Palo Verde unit.

Nuclear Fuel Financing. Pursuant to the ANPP Participation Agreement, the Company owns an undivided interest in nuclear fuel purchased in connection with Palo Verde. The Company has available a total of $100 million under a revolving credit facility that provides for both working capital and up to $70 million for the financing of nuclear fuel. This facility was renewed in 2004 for a five-year term ending December 17, 2009. At December 31, 2004, approximately $41.2 million had been drawn to finance nuclear fuel. This financing is accomplished through a trust that borrows under the credit facility to acquire and process the nuclear fuel. The Company is obligated to repay the trust's borrowings with interest and has secured this obligation with First Mortgage Collateral Series Bonds. The Company

Natural Gas

The Company manages its natural gas requirements through a combination of a long-term supply contract and spot market purchases. The long-term supply contract provides for firm deliveries of gas at market-based index prices. In 2004, the Company's natural gas requirements at the Rio Grande Power Station were met with both short-term and long-term natural gas purchases from various suppliers. This is expected to continue in 2005. Interstate gas is delivered under a base firm transportation contract that expires in July 2005. The Company expects to renew this contract beyond 2005, on terms to be negotiated between the parties. The Company anticipates it will continue to purchase natural gas at spot market prices on a monthly basis for a portion of the fuel needs for the Rio Grande Power Station for the near term. The Company will continue to evaluate the availability of short-term natural gas supplies versus long-term supplies to maintain a reliable and economical supply for the Rio Grande Power Station.

Natural gas for the Newman and Copper Power Stations is primarily supplied pursuant to an intrastate natural gas contract that expires in 2007. The Company will also continue to evaluate short-term natural gas supplies to maintain a reliable and economical supply for the Newman and Copper Power Stations.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. APS, on behalf of the Company and the other Four Corners Participants, has extended the Four Corners coal contract with the supplier to 2016 to coincide with the Four Corners Plant lease with the Navajo Nation. Based upon information from APS, the Company believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements for its useful life.

In the fourth quarter of 2004, upon preliminary review of a study conducted by an outside engineering firm, the Company increased its estimated final reclamation and coal mine closure liability related to the Company's interest in Four Corners from $7.4 million to $10.5 million. The $3.1 million increase (in 2004 pre-tax dollars) in its estimated reclamation and coal mine closure liability resulted in a $2.4 million charge to energy expense and a $0.7 million increase in regulatory assets.

Purchased Power

To supplement its own generation and operating reserves, the Company engages in firm and non-firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs and the economics of the transactions. The Company purchased 103 MW of firm energy in 2004 and will continue to purchase an identical annual amount through 2005 based on a purchase agreement entered into in 2001. This agreement includes demand, energy and transmission charges. In 2004, the Company entered into a 20-year contract, beginning in 2006, for the purchase of up to 133 MW of capacity and associated energy from SPS. This contract includes a demand charge, energy charge and a transmission charge. Other purchases of shorter duration were made primarily to replace the Company's generation resources during planned and unplanned outages.

Operating Statistics

	Years Ended December 31,		
	2004	2003	2002
Operating revenues:			
Base revenues:			
Retail:			
Residential	$ 174,752	$ 171,459	$ 166,320
Commercial and industrial, small	165,760	165,434	163,553
Commercial and industrial, large	43,150	43,294	43,419
Sales to public authorities	72,720	73,136	70,802
Total retail base revenues	456,382	453,323	444,094
Wholesale:			
Sales for resale	1,675	3,223	32,228
Total base revenues	458,057	456,546	476,322
Fuel revenues	161,052	122,761	158,650
Economy sales	78,533	76,536	43,654
Other	10,986	8,519	11,459
Total operating revenues	$ 708,628	$ 664,362	$ 690,085
Number of customers (end of year):			
Residential	296,435	289,179	281,874
Commercial and industrial, small	31,079	30,254	29,281
Commercial and industrial, large	58	63 (1)	64 (1)
Other	4,553	4,524	4,431
Total	332,125	324,020	315,650
Average annual kWh use per residential customer	6,769	6,761	6,694
Energy supplied, net, kWh (in thousands):			
Generated	7,611,465	7,740,923	7,785,938
Purchased and interchanged	1,410,114	1,250,707	1,549,875
Total	9,021,579	8,991,630	9,335,813
Energy sales, kWh (in thousands):			
Retail:			
Residential	1,986,085	1,932,171	1,870,931
Commercial and industrial, small	2,115,822	2,096,860	2,076,758
Commercial and industrial, large	1,236,426	1,197,065	1,161,815
Sales to public authorities	1,243,003	1,224,349	1,212,180
Total retail	6,581,336	6,450,445	6,321,684
Wholesale:			
Sales for resale	41,094	67,754	986,134
Economy sales	1,838,467	1,920,882	1,483,465
Total wholesale	1,879,561	1,988,636	2,469,599
Total energy sales	8,460,897	8,439,081	8,791,283
Losses and Company use	560,682	552,549	544,530
Total	9,021,579	8,991,630	9,335,813
Native system:			
Peak load, kW	1,332,000	1,308,000	1,282,000
Net generating capacity for peak, kW	1,500,000	1,500,000	1,500,000
Total system:			
Peak load, kW (2)	1,575,000	1,546,000	1,509,000
Net generating capacity for peak, kW (3)	1,500,000	1,500,000	1,500,000
System capacity factor (4)	60.1%	60.1%	61.1%

(1) Revised to conform with new 2004 commercial and industrial large billing system which counts customers by service location rather than by meter. This change did not affect sales or revenues of the Company.

(2) Includes spot firm sales of 245,000 kW, 355,000 kW and 150,000 kW for 2004, 2003 and 2002, respectively.

(3) Excludes 103,000 kW, 103,000 kW and 153,000 kW of firm on and off-peak purchases for 2004, 2003 and 2002, respectively.

(4) System capacity factor includes average firm system purchases of 103,000 kW, 103,000 kW and 143,000 kW for 2004, 2003 and 2002, respectively.

Regulation

General

In 1999, both the Texas and New Mexico legislatures enacted electric utility industry restructuring laws requiring competition in certain functions of the industry and ultimately in the Company's service area. In Texas, the Company has been exempt from the requirements of the Texas Restructuring Law, including utility restructuring and retail competition. The Texas Commission recently adopted a rule that would further delay competition in the Company's Texas service territory until at least the time that an independent regional transmission organization ("RTO") begins operation in its relevant power markets. In April 2003, the New Mexico Restructuring Act was repealed and as a result, the Company's operations in New Mexico will continue to be fully regulated. The Company cannot predict at this time the full effects the repeal of the New Mexico Restructuring Act will have on the Company should it be required to ultimately implement the Texas Restructuring Law.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The FERC has been conducting an investigation into potential manipulation of electricity prices in the western United States during 2000 and 2001. On August 13, 2002, the FERC initiated a Federal Power Act ("FPA") investigation into the Company's wholesale power trading in the western United States during 2000 and 2001 to determine whether the Company and Enron engaged in misconduct and, if so, to determine potential remedies. The Company reached settlements with the FERC and other parties in 2002 and 2003. The Company believes the FERC's order resolved all issues between the FERC and the other parties to this investigation. Under the settlements, the Company agreed to refund $15.5 million and to make wholesale sales pursuant to its cost of service rate authority rather than its market-based rate authority for the period December 1, 2002 through December 31, 2004. This agreement allowed the Company to sell power into wholesale markets at its incremental cost plus $21.11 per MWh. To the extent that wholesale market prices exceeded these agreed upon amounts, the Company lost the opportunity to realize these additional revenues. This provision did not have a significant impact on the Company's revenues through December 31, 2004. The Company's ability to make wholesale sales pursuant to its market-based rate authority was restored on January 1, 2005.

RTOs. FERC's rule ("Order 2000") on RTOs strongly encourages, but does not require, public utilities to form and join RTOs. The Company is an active participant in the development of WestConnect, formerly known as the Desert Southwest Transmission and Reliability Operator. As a participating transmission owner, the Company will ultimately transfer operational authority of its transmission system to WestConnect subject to receiving any necessary regulatory approvals. On October 10, 2002, FERC issued an order indicating that the Company's WestConnect proposal satisfied, or with certain modifications would satisfy, the FERC requirements for an RTO under Order 2000. WestConnect will continue to work with the FERC and two other proposed RTOs in the west to achieve a seamless market structure. The Company, however, is anticipated to be no more than a 9% participant in WestConnect and cannot control the terms or timing of its establishment. WestConnect will not be operational for several years. The establishment of an independent RTO in the Company's service area is a prerequisite for the Company to be considered part of a Qualified Power Region as defined in the

Texas Restructuring Law. The timing of the operations of WestConnect could affect when and whether the Company's Texas service territory is deregulated under the Texas Restructuring Law.

Department of Energy. The DOE regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. The DOE has determined that all such exports over international transmission lines shall be made in accordance with Order No. 888, which established the FERC rules for open access.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See "Facilities – Palo Verde Station – Spent Fuel Storage" for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards. The NRC also has the authority to conduct environmental reviews pursuant to the National Environmental Policy Act.

Texas Regulatory Matters

The rates and services of the Company are regulated in Texas by municipalities and by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services within municipalities in Texas and original jurisdiction over certain other activities of the Company. The decisions of the Texas Commission are subject to judicial review.

Deregulation. The Texas Restructuring Law required certain investor-owned electric utilities to separate power generation activities from transmission and distribution activities by January 1, 2002, and on that date, retail competition for generation services was instituted in some parts of Texas. The Texas Restructuring Law, however, specifically recognized and preserved the Company's Texas Rate Stipulation and Texas Settlement Agreement by, among other things, exempting the Company's Texas service area from retail competition until the end of the Freeze Period. On October 13, 2004, the Texas Commission approved a rule further delaying retail competition in the Company's Texas service territory. The rule approved by the Texas Commission sets a schedule which identifies various milestones for the Company to reach before competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a RTO, including the development of retail market protocols to facilitate retail competition. The complete transition to retail competition would occur upon the completion of the last milestone which would be the Texas Commission's final evaluation of the market's readiness to offer fair competition and reliable service to all retail customers. The Company believes that adoption of this rule will likely delay retail competition in El Paso for at least several years. There is substantial uncertainty about both the regulatory framework and market conditions that will exist if and when retail competition is implemented in the Company's service territory, and the Company may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect the future operations, cash flows and financial condition of the Company.

Renewables and Energy Efficiency Programs. Notwithstanding the Commission's approval of a rule further delaying competition in the Company's Texas service territory, the Company will become subject to the renewable energy and energy efficiency requirements of the Texas Restructuring Law on January 1, 2006. Under the renewable energy requirements, the Company will have to annually obtain its pro rata share of renewable energy credits as determined by the Texas Commission, based on total Texas retail sales subject to renewable energy credit allocation. The Company's ultimate obligation to obtain renewable energy credits will not be known until January 31 of the year following the compliance year, and it will have until March 31 to obtain, if necessary, and submit to the Texas Commission, sufficient credits. In addition, by January 1, 2007 and January 1, 2008, the Company will be required to fund incentives for energy efficiency savings that will achieve the goal of meeting 5% and 10% of its growth in demand through energy efficiency savings, respectively. Preparatory costs incurred by the Company to meet these requirements will not be recoverable in the Company's Texas service territory prior to the expiration of the Freeze Period.

Termination of Freeze Period. The Freeze Period expires on August 1, 2005. Thereafter, the Company will be subject to traditional cost of service regulation by the Texas cities it serves and by the Texas Commission. Its present rates will stay in effect until changed by a city or the Texas Commission. Any such change would be initiated with either a request by the Company or a complaint by a regulator or customer. Any rate change order would be preceded by discovery and presentation of evidence. Any decision by a city would be subject to appellate review by the Texas Commission. The Company has no present intention to request a base rate change, and no complaints against the Company's base rates are pending.

The end of the Freeze Period may also bring an end to the 50/50 sharing of off-system sales margins between the Company and its customers. The current fuel rule in Texas provides that such margins are to be fully credited to customers.

The Company's ten-year franchise with the City of El Paso ("City") expires on August 1, 2005. The franchise governs the Company's usage of City-owned property, including the payment of franchise fees.

The Company is meeting with the City to discuss the Company's franchise and rate treatment after the expiration of the Freeze Period. The Company is unable to predict the outcome of these discussions.

Fuel. Although the Company's base rates are frozen in Texas pursuant to Texas Commission rules and the Texas Rate Stipulation, the Company can request adjustments to its fuel factor to more accurately reflect projected energy costs associated with providing electricity and seek recovery of past undercollections of fuel revenues, subject to periodic final review by the Texas Commission in fuel reconciliation proceedings.

The Company reconciled its Texas jurisdictional fuel costs for the period January 1, 1999 through December 31, 2001 in PUC Docket No. 26194, and on May 5, 2004, the Texas Commission issued its final order. At issue was the Company's request to recover an additional $15.8 million, before interest, from its Texas customers as a surcharge due to fuel undercollections from January 1999 through December 2001. The Texas Commission disallowed approximately $4.5 million of Texas jurisdictional

expenses, before interest, consisting primarily of (i) approximately $4.2 million of purchased power expenses which the Texas Commission characterized as "imputed capacity charges," and (ii) approximately $0.3 million in fees which were deemed to be administrative costs, not recoverable as fuel. This disallowance was recorded as a reduction of fuel revenue during the fourth quarter of 2003. In Texas, capacity charges are not eligible for recovery as fuel expenses but are to be recovered through the Company's base rates. As the Company's base rates were frozen during the period in which the imputed capacity charges were deemed to have been incurred, the $4.2 million of imputed capacity charges were therefore permanently disallowed, and not recoverable from its Texas customers. The Texas Commission's decision has been appealed by two parties and the Company, and the Company is unable to predict the ultimate outcome of the appeals.

The Company has incurred similar purchased power costs for the fuel reconciliation period beginning January 1, 2002. The Company believes that it has accounted for its purchased power costs during the reconciliation period beginning January 2002 in a manner consistent with the Texas Commission's decision in PUC Docket No. 26194. However, the Texas Commission recently commenced a generic rulemaking proceeding to determine a statewide policy for the appropriate pricing of capacity in purchased power contracts. On August 31, 2004, the Company filed an application (PUC Docket No. 30143) to reconcile Texas jurisdictional fuel costs for the period January 1, 2002 to February 29, 2004. There can be no assurance as to the outcome of the rulemaking and its potential impact on the Company with respect to fuel recovery in future reconciliation periods, including those in PUC Docket No. 30143.

Palo Verde Performance Standards. The Texas Commission established performance standards for the operation of Palo Verde pursuant to which each Palo Verde unit is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission can also reconsider the rate treatment of Palo Verde, regardless of the provisions of the Texas Rate Stipulation and the Texas Settlement Agreement. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Under the performance standards as modified by the Texas Fuel Settlement, the Company has calculated the performance rewards for the reporting periods ending in 2004, 2003 and 2002 to be approximately $0.2 million, $0.8 million and $1.3 million, respectively. These rewards will be included, along with energy costs incurred and revenues billed, as part of the Texas Commission's review during a future periodic fuel reconciliation proceeding as discussed above. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel proceeding or comparable evidence of collectibility is obtained. Performance penalties are recorded when assessed as probable by the Company.

New Mexico Regulatory Matters

The New Mexico Commission has jurisdiction over the Company's rates and services in New Mexico and over certain other activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. The largest city in the Company's New Mexico service territory is Las Cruces.

Deregulation. In April 2003, the New Mexico Restructuring Act was repealed, and as a result, the Company's operations in New Mexico will continue to be fully regulated. The Company cannot predict at this time the full effects the repeal of the New Mexico Restructuring Act will have on the Company if it ultimately transitions to retail competition in Texas.

New Mexico Rate Stipulation. On June 1, 2004, the Company implemented new rates according to the New Mexico Stipulation whereby, among other things, the Company agreed for a period of three years beginning June 1, 2004 to (i) freeze base rates after an initial non-fuel base rate reduction of 1%; (ii) fix fuel and purchased power cost associated with 10% of the Company's jurisdictional retail sales in New Mexico at $0.021 per kWh; (iii) leave subject to reconciliation the remaining 90% of the Company's New Mexico jurisdictional fuel and purchased power costs not collected in base rates; (iv) continue the collection of a portion of fuel and purchased power costs in base rates as presently collected in the amount of $0.01949 per kWh; (v) price power provided from Palo Verde Unit 3 to the extent of its availability at an 80% nuclear, 20% gas fuel mix; and (vi) deem reconciled, for the period June 15, 2001 through May 31, 2004, the Company's fuel and purchased power costs for the New Mexico jurisdiction.

Fuel. In April 2004, the New Mexico Commission, as part of the New Mexico Stipulation, approved a fuel and purchased power cost adjustment clause. The Company will continue to recover fuel and purchased power costs in base rates in the amount of $0.01949 per kWh and continue the fuel and purchased power cost adjustment to recover 90% of the remaining fuel and purchased power costs. Fuel and purchased power costs associated with the remaining 10% of the Company's jurisdictional retail sales in New Mexico are fixed at $0.021 per kWh. The Company and all intervenors entered into the New Mexico Stipulation on the Company's compliance filing.

Renewables. The New Mexico Renewable Energy Act of 2004 requires that, by January 1, 2006, renewable energy comprise no less than 5% of the Company's total retail sales to New Mexico customers. The requirement increases by 1% annually until January 1, 2011, when the renewable portfolio standard shall reach a level of 10% of the Company's total retail sales to New Mexico customers and will remain fixed at such level thereafter. On September 1, 2004, the Company filed its Transitional Procurement Plan detailing its proposed actions to comply with the Renewable Energy Act.

The New Mexico Commission approved the Company's Transitional Procurement Plan with modifications to shorten the term for the Company's proposed contract to purchase renewable energy credits and to address diversity provisions of the Renewable Energy Act. These modified provisions will be incorporated into the renewable procurement plan to be filed by the Company no later than September 1, 2005 for the 2006 year. Costs incurred by the Company to meet the requirements of the New Mexico Renewable Energy Act are to be recovered from New Mexico customers pursuant to the Renewable Energy Act and the New Mexico Commission's rules.

Sales for Resale

The Company provides up to 10 MW of firm capacity, associated energy, and transmission service to the Rio Grande Electric Cooperative pursuant to an ongoing contract which requires a two-year notice to terminate. No such notice has been received.

Power Sales Contracts

On November 9, 2004, the Company entered into transactions for the sale of 50 MW to be supplied during the off-peak periods in 2005. The revenues from these sales are anticipated to be approximately $8.2 million in 2005.

The Company also has an agreement with a counterparty for power exchanges under which the Company received 30 MW of on-peak capacity and associated energy during 2004 at the Eddy County tie and concurrently delivered the same amount at Palo Verde and/or Four Corners. The on-peak exchange amount remains at 30 MW through 2005. The agreement also gives the counterparty the option to deliver up to 133 MW of off-peak capacity and associated energy through 2005 at the Eddy County tie and concurrently receive the same amount at Palo Verde and/or Four Corners. The Company will receive a guaranteed margin on any energy exchanged under the off-peak agreement. See "Purchased Power."

Franchises and Significant Customers

City of El Paso Franchise

The Company's largest franchise agreement is with the City. The franchise agreement includes a 2% annual franchise fee (approximately $7.9 million per year currently) and allows the Company to utilize public rights-of-way necessary to serve its retail customers within the City. The franchise with the City extends through August 1, 2005.

The Company's franchise agreement with the City included an option to acquire all of the non-cash assets of the Company at the end of the term of the franchise on August 1, 2005. To exercise the option, the City was required to deliver written notice to the Company one year prior to the expiration of the franchise term. The option expired unexercised on August 1, 2004.

Las Cruces Franchise

In February 2000, the Company and Las Cruces entered into a seven-year franchise agreement with a 2% annual franchise fee (approximately $1.2 million per year currently) for the provision of electric distribution service. Las Cruces is prohibited during this seven-year period from taking any action to condemn or otherwise attempt to acquire the Company's distribution system, or attempt to operate or build its own electric distribution system. Las Cruces will have a 90-day non-assignable option at the end of the Company's seven-year franchise agreement to purchase the portion of the Company's distribution system that serves Las Cruces at a purchase price of 130% of the Company's book value at that time. If Las Cruces exercises this option, it is prohibited from reselling the distribution assets for two years. If Las Cruces fails to exercise this option, the franchise and standstill agreements will be extended for an additional two years.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represent approximately 3% of annual operating revenues. The Company currently has contracts with all three military bases that it serves. The Company signed a

contract with Ft. Bliss in December 1998 under which Ft. Bliss will take retail electric service from the Company through December 2008. The Company has a contract to provide retail electric service and limited wheeling services to Holloman for a ten-year term which expires in December 2005. In May 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands.

Risk Factors

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory, fuel prices, the performance of our customers and the decisions of regulatory agencies. Our common stock price and creditworthiness will be affected by national and international macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial condition and results of operations. These are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Our Costs Could Increase if There are Problems at the Palo Verde Nuclear Generating Station

A significant percentage of our generating capacity, assets and operating expenses is attributable to Palo Verde. The Company's 15.8% interest in each of the three Palo Verde units total approximately 600 MW of generating capacity. Palo Verde represents approximately 40% of our available net generating capacity and represented approximately 49% of our available energy for the twelve months ended December 31, 2004. Nuclear fuel represented approximately 49% of the total kWh energy mix of the Company for the twelve months ended December 31, 2004. We face the risk of additional or unanticipated costs at Palo Verde resulting from (i) increases in operation and maintenance expenses; (ii) the replacement of steam generators in Palo Verde Units 1 and 3; (iii) an extended outage of any of the Palo Verde units; (iv) increases in estimates of decommissioning costs; (v) the storage of radioactive waste, including spent nuclear fuel; (vi) insolvency of other Palo Verde Participants; and (vii) compliance with the various requirements and regulations governing commercial nuclear generating stations. At the same time, the Company's retail base rates in Texas are effectively capped through a rate freeze ending in August 2005. As a result, the Company cannot raise its base rates in Texas prior to the expiration of the Freeze Period in the event of increases in non-fuel costs or loss of revenue. Additionally, should retail competition occur, there may be competitive pressure on the Company's power generation rates which could reduce its profitability. The Company cannot assure that its revenues will be sufficient to recover any increased costs, including any increased costs in connection with Palo Verde or other operations, whether as a result of inflation, changes in tax laws or regulatory requirements, or other causes.

Our Retail Rates Are Subject to Change Following the Termination of our Ten-Year Rate Freeze in August 2005

Our rates in Texas, which account for 68% of our revenues, have been frozen and not subject to regulatory review since August 2, 1995. The Freeze Period expires on August 1, 2005. Thereafter, we will be subject to traditional cost of service regulation by the Texas cities that we serve and the Texas Commission. There can be no assurance that we will be able to maintain our Texas rates after expiration of the Freeze Period. In addition, the end of the Freeze Period may mean that we will no longer be entitled to retain 50% of our margins from off-system sales. If a return to cost of service regulation leads to lower rates or the retention by us of less of the margin from off-system sales, there would be a material negative impact on our revenues, earnings, cash flows and financial position.

Our Franchise With the City of El Paso Expires in August 2005

El Paso is the largest city in our service area, representing 59% of our revenues for the twelve months ended December 31, 2004. Our ten-year franchise with the City of El Paso expires on August 1, 2005 and there can be no assurance that we will be able to negotiate a new franchise on terms that are acceptable to us.

We May Not Be Able to Pass Through All of Our Fuel Expenses to Customers

In general, through regulation, we can pass through our fuel and purchased power expenses to our customers. Nevertheless, we agreed in 2004 to a fixed fuel factor for ten percent of our retail customers in New Mexico. This subjects us to the risk of increased costs of fuel that would not be recoverable. The portion of fuel expense that is not fixed is subject to reconciliation by the Texas and New Mexico Commissions. Prior to the completion of a reconciliation, the Company records fuel transactions such that fuel revenues equal fuel expense except for the portion fixed in New Mexico. In the event that a disallowance occurs during a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts allowed to be collected by us from our customers and we would incur a loss to the extent of the disallowance.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity require the use of expensive and complex equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. We are particularly vulnerable to this due to the advanced age of several of our generating units in or near El Paso. In these events, we must acquire power from others at unpredictable costs in order to supply our customers and comply with our contractual agreements. This can increase our costs materially and prevent us from selling excess power at wholesale, thus reducing our profits. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. We are particularly vulnerable to this because a significant portion of our available energy (at Palo Verde and Four Corners) is located hundreds of miles from El Paso and Las Cruces and must be delivered to our customers over long distance transmission lines. These factors, as well as weather, interest rates, economic conditions, fuel prices and price volatility, are largely beyond our control, but may have a material adverse effect on our consolidated earnings, cash flows and financial position.

Competition and Deregulation Could Result in a Loss of Customers and Increased Costs

As a result of changes in federal law, our wholesale and large retail customers already have, in varying degrees, alternate sources of economical power, including co-generation of electric power. In addition, in recent years, both New Mexico and Texas passed industry deregulation legislation requiring us to separate our transmission and distribution functions, which would remain regulated, from our

power generation and energy services businesses, which would operate in a competitive market, in the future. New Mexico repealed the New Mexico Restructuring Act in April 2003, and the Company's operations in New Mexico will remain fully regulated. On October 13, 2004, the Texas Commission approved a rule delaying retail competition in the Company's Texas service territory. There is substantial uncertainty about both the regulatory framework and market conditions that would exist if and when retail competition is implemented in the Company's Texas service territory, and we may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect our future operations, cash flows and financial condition.

Executive Officers of the Registrant

The executive officers of the Company as of February 28, 2005, were as follows:

Name	Age	Current Position and Business Experience
Gary R. Hedrick	50	Chief Executive Officer, President and Director since November 2001; Executive Vice President, Chief Financial and Administrative Officer from August 2000 to November 2001; Vice President, Chief Financial Officer and Treasurer from August 1996 to August 2000.
Terry Bassham (1)	44	Executive Vice President, Chief Financial and Administrative Officer since November 2001; Executive Vice President and General Counsel from August 2000 to November 2001; Vice President and General Counsel from January 1999 to August 2000.
J. Frank Bates	54	Executive Vice President and Chief Operations Officer since November 2001; Vice President – Transmission and Distribution from August 1996 to November 2001.
Raul A. Carrillo, Jr.	42	Senior Vice President, General Counsel and Corporate Secretary since February 2003; Senior Vice President and General Counsel from July 2002 to February 2003; General Counsel from January 2002 to July 2002; Associate and Shareholder with Sandenaw, Carrillo & Piazza, P.C. from March 1996 to January 2002.
Steven P. Busser	36	Vice President – Regulatory Affairs and Treasurer since February 2005; Treasurer from February 2003 to February 2005; Assistant Chief Financial Officer from June 2002 to February 2003; Vice President – International Controller for Affiliated Computer Services, Inc. from August 2001 to June 2002; Vice President – International Controller for National Processing Company, Inc. from June 2000 to August 2001; Assurance Manager with KPMG, LLP from June 1998 to June 2000.
Fernando J. Gireud	47	Vice President – Power Marketing and International Business since February 2003; Vice President – International Business from July 2002 to February 2003; Director – International Business Affairs from February 2002 to July 2002; Director – International Business Affairs – MiraSol from November 1999 to February 2002; Manager of Environmental Affairs from April 1994 to November 1999.
Helen Knopp	62	Vice President – Customer and Public Affairs since April 1999.
Kerry B. Lore	45	Vice President – Administration since May 2003; Controller from October 2000 to May 2003; Assistant Controller from April 1999 to October 2000.
Robert C. McNiel	58	Vice President – New Mexico Affairs since December 1997.
Hector R. Puente	48	Vice President – Power Generation since April 2001; Manager – Substations and Relaying from August 1996 to April 2001.
Guillermo Silva, Jr.	51	Vice President – Information Services since February 2003; Secretary from January 1994 to February 2003.
John A. Whitacre	55	Vice President – Transmission and Distribution since July 2002; Assistant Vice President – System Operations from August 1989 to July 2002.
Scott D. Wilson	51	Vice President – Corporate Planning and Controller since February 2005; Controller from September 2003 to February 2005; Owner of Wilson Consulting Group from June 1992 to September 2003.

(1) On March 4, 2005, Mr. Bassham announced his resignation from the Company, effective as of March 18, 2005, to accept a similar position with another public utility company.

The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors.

Item 2. Properties

The principal properties of the Company are described in Item 1, "Business," and such descriptions are incorporated herein by reference. Transmission lines are located either on private rights-of-way, easements, or on streets or highways by public consent. Substantially all of the Company's utility plant is subject to liens to secure the First Mortgage Bonds.

In addition, the Company leases executive and administrative offices in El Paso, Texas under a lease which expires in May 2007 and certain warehouse facilities in El Paso, Texas under a lease which expires in January 2006 with two concurrent renewal options of six months each.

Item 3. Legal Proceedings

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, the Company believes that, except as described below, none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

On January 16, 2003, the Company was served with a complaint on behalf of a purported class of shareholders alleging violations of the federal securities laws (*Roth v. El Paso Electric Company, et al.*, No. EP-03-CA-0004). The complaint was filed in the El Paso Division of the United States District Court for the Western District of Texas. The suit seeks undisclosed compensatory damages for the class as well as costs and attorneys' fees. The lead plaintiff, Carpenters Pension Fund of Illinois, filed a consolidated amended complaint on July 2, 2003, alleging, among other things, that the Company and certain of its current and former directors and officers violated securities laws by failing to disclose that some of the Company's revenues and income were derived from an allegedly unlawful relationship with Enron. The allegations arise out of the FERC investigation of the power markets in the western United States during 2000 and 2001, which the Company previously settled with the FERC Trial Staff and certain intervening parties. On August 15, 2003, the Company and the individual defendants filed a motion to dismiss the complaint for failure to state a claim upon which relief can be granted. On November 26, 2003, the Court denied the motion to dismiss as to the Company and three of the individual defendants and granted the motion to dismiss as to two individual defendants. On April 13, 2004, the Court granted a motion of the Company and the remaining individual defendants requesting permission to file an interlocutory appeal to the U. S. Court of Appeals for the Fifth Circuit regarding certain legal questions relating to the Court's denial of the motion to dismiss the complaint as to those defendants. On April 27, 2004, the Court entered an order staying the district court proceedings until the Fifth Circuit completed its review. On June 7, 2004, the U. S. Court of Appeals denied the appeal which automatically lifted the stay in the district court. This matter is presently set for trial on September 19, 2005, but such date may be extended. While the Company believes the lawsuit is without merit and intends to defend itself vigorously, the Company is unable to predict the outcome or the range of any possible loss.

On May 21, 2003, the Company was served with a complaint by the Port of Seattle seeking civil damages under the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, and state anti-trust laws, as well as for fraud (*Port of Seattle v. Avista Corporation, et al.*, No. CV03-117OP). The complaint was filed in the United States District Court for the Western District of Washington. The complaint alleges that the Company, indirectly through its dealings with Enron, conspired with the other named defendants to manipulate the California energy market, which had the effect of artificially inflating the price that the Port of Seattle paid for electricity. The Company, together with several other defendants, filed a motion to dismiss. On May 12, 2004, the Court granted the Company's motion, and the suit was dismissed. The Port of Seattle has filed an appeal of the Court's decision with the U. S. Court of Appeals for the Ninth Circuit. The parties have filed briefs and are awaiting a hearing and decision. While the Company believes that these matters are without merit, the Company is unable to predict the outcome or range of any possible loss.

On November 3, 2003, TNP filed a complaint against the Company with the FERC, asking the FERC to make a determination that TNP has certain "rollover rights" to network-type transmission service over the Company's transmission system as a result of a power sales agreement between it and the Company which expired at the end of 2002. TNP asserted that it has such rights under the rollover provisions of FERC Order No. 888. The Company responded to TNP's complaint by contesting TNP's assertion of rollover rights on several grounds. Due to existing transmission constraints, a FERC ruling granting TNP's complaint could have adversely impacted the Company's ability to import lower cost power from Palo Verde and Four Corners to serve its retail customers, which could have resulted in higher rates for the Company's retail electric customers. A hearing on this matter before an administrative law judge ("ALJ") was held on July 19 and 20, 2004, and, on September 20, 2004, the ALJ issued a proposed decision, dismissing TNP's complaint and concluding that TNP has no rollover rights over the Company's transmission system. On March 2, 2005, the Commission issued its order affirming the dismissal of TNP's complaint.

On June 29, 2004, the Company filed suit against TNP in the Third Judicial District Court of New Mexico, claiming that TNP acted in bad faith by claiming such transmission rights and seeking to obtain use of more transmission rights than originally allocated to TNP under its original contract with the Company. The Company seeks both actual and exemplary damages from TNP as well as a declaration that TNP breached its agreements with the Company, acted in bad faith and violated New Mexico law prohibiting such actions. On November 1, 2004, the Company filed a motion for leave to amend the complaint to add PNM as a defendant in this action, alleging, among other things, that PNM tortiously interfered with the Company's contractual relationships with TNP. On November 22, 2004, the Company, TNP and PNM entered into a settlement agreement (contingent upon FERC approval) whereby (i) TNP would withdraw its complaint against the Company with the FERC and no longer seek certain rollover transmission rights from the Company; (ii) the Company would dismiss its claims against TNP and PNM in the New Mexico district court; and (iii) TNP would reimburse the Company for certain costs incurred in defending the FERC action. On March 2, 2005, the settlement was approved by the FERC.

On May 5, 2004, Wah Chang, a specialty metals manufacturer which operates a plant in Oregon, filed suit against the Company and other defendants in the United States District Court for the District of

Oregon. (*Wah Chang v. Avista Corporation, et al.,* No. 04-619AS). The complaint makes substantially the same allegations as were made in *Port of Seattle* and seeks the same types of damages. In addition, on June 7, 2004, the City of Tacoma filed suit against the Company and other defendants in the United States District Court for the Western District of Washington (*City of Tacoma v. American Electric Power Service Corp., et al.,* C04-5325RBL). This complaint also makes substantially the same allegations as were made in *Port of Seattle* and seeks civil damages (including treble damages) from the Company and the other defendants for violations of certain antitrust provisions under the Sherman Act. Both of these matters were transferred to the same court that heard and dismissed the *Port of Seattle* lawsuit and on February 11, 2005, the Court granted the Company's motion to dismiss both cases. Wah Chang and the City of Tacoma have thirty days in which to appeal the Court's decision with the U.S. Court of Appeals for the Ninth Circuit. While the Company believes that these matters are without merit, the Company is unable to predict the outcome or range of any possible loss.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to vote of the Company's security holders through the solicitation of proxies or otherwise during the fourth quarter of 2004.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Repurchases of Equity Securities

The Company's common stock trades on the New York Stock Exchange under the symbol "EE." The high, low and close sales prices for the Company's common stock, as reported in the consolidated reporting system of the New York Stock Exchange for the periods indicated below were as follows:

	Sales Price		
	High	Low	Close (End of period)
2003			
First Quarter	$ 11.99	$ 10.10	$ 10.80
Second Quarter	12.50	10.76	12.33
Third Quarter	12.55	10.90	11.55
Fourth Quarter	13.63	11.55	13.35
2004			
First Quarter	$ 14.68	$ 13.07	$ 13.84
Second Quarter	15.60	13.42	15.44
Third Quarter	16.10	14.58	16.07
Fourth Quarter	19.12	15.90	18.94

As of February 28, 2005, there were 4,456 holders of record of the Company's common stock. The Company does not anticipate paying dividends on its common stock in the near-term. The Company intends to continue its stock repurchase programs and to repurchase debt with coupons in excess of market rates when it is economically advantageous to do so, with the goal of maintaining or improving its capital structure, bond ratings, and earnings per share.

Since the inception of the stock repurchase programs in 1999, the Company has repurchased approximately 15.3 million shares in total at an aggregate cost of $175.6 million, including commissions. During 2004, the Company repurchased 294,842 shares of common stock for $4.5 million, including commissions, pursuant to the two million share buyback program authorized by its Board of Directors in February 2004. An additional 1,705,158 shares are authorized to be repurchased under the program. No shares were repurchased during the fourth quarter of 2004. The Company may continue making purchases of its stock pursuant to its stock repurchase plan at open market prices and may engage in private transactions, where appropriate. The repurchased shares will be available for issuance under employee benefit and stock option plans, or may be retired.

Item 6. Selected Financial Data

As of and for the following periods (in thousands except for share data):

	Years Ended December 31,				
	2004	2003	2002	2001	2000
Operating revenues	$ 708,628	$ 664,362	$ 690,085	$ 769,705	$ 701,649
Operating income	93,622	79,735	110,127	167,122	168,495
Income before extraordinary item and cumulative effect of accounting change	33,369	20,322	28,674	63,365	58,099
Extraordinary gain on re-application of SFAS No. 71, net of tax	1,802	–	–	–	–
Cumulative effect of accounting change, net of tax	–	39,635	–	–	–
Net income	35,171	59,957	28,674	63,365	58,099
Basic earnings per share:					
Income before extraordinary item and cumulative effect of accounting change	0.70	0.42	0.58	1.25	1.07
Extraordinary gain on re-application of SFAS No. 71, net of tax	0.04	–	–	–	–
Cumulative effect of accounting change, net of tax	–	0.82	–	–	–
Net income	0.74	1.24	0.58	1.25	1.07
Weighted average number of shares outstanding	47,426,813	48,424,212	49,862,417	50,821,140	54,183,915
Diluted earnings per share:					
Income before extraordinary item and cumulative effect of accounting change	0.69	0.42	0.57	1.23	1.06
Extraordinary gain on re-application of SFAS No. 71, net of tax	0.04	–	–	–	–
Cumulative effect of accounting change, net of tax	–	0.81	–	–	–
Net income	0.73	1.23	0.57	1.23	1.06
Weighted average number of shares and dilutive potential shares outstanding	48,019,721	48,814,761	50,380,468	51,722,351	55,001,625
Cash additions to utility property, plant and equipment	72,499	77,080	65,065	70,739	64,612
Total assets	1,581,355	1,596,614	1,648,229	1,646,158	1,662,304
Long-term debt and financing and capital lease obligations, net of current portion	379,636	608,722	614,375	619,365	740,223
Common stock equity	532,147	495,768	452,882	446,726	408,861

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

As you read this Management's Discussion and Analysis, please refer to the Company's Consolidated Financial Statements and the accompanying notes, which contain the Company's operating results.

Summary of Critical Accounting Policies and Estimates

Note A to the Consolidated Financial Statements contains a summary of the significant accounting policies utilized by the Company. The preparation of these statements requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and related notes for the periods presented and actual results could differ in future periods from those estimates. Critical accounting policies and estimates, which are both important to the portrayal of the Company's financial condition and results of operations and which require complex, subjective judgments, include the following:

- SFAS No. 71
- Collection of fuel expense
- Value of net utility plant in service
- Decommissioning costs and estimated asset retirement obligation
- Future pension and other postretirement obligations
- Reserves for tax dispute

SFAS No. 71

Regulated electric utilities typically prepare their financial statements in accordance with SFAS No. 71. Under this accounting standard, certain recoverable costs are shown as either assets or liabilities on a utility's balance sheet if the regulator provides assurance that these costs will be charged to and collected from its customers (or has already permitted such cost recovery). The resulting regulatory assets or liabilities are amortized in subsequent periods based upon their respective amortization periods in a utility's cost of service.

Beginning in 1991, the Company discontinued the application of SFAS No. 71 to its financial statements. This decision was based on the Company's determination that its rates were no longer designed to recover its costs of providing service to customers. Upon emerging from bankruptcy in 1996, the Company again concluded that it did not meet the criteria for applying SFAS No. 71 because of the ten-year rate freeze in Texas and its ongoing intention not to seek changes in its New Mexico rates, which had been established in 1990. Although the Company believes the rates established in 1995 were based upon its costs of service, the unusual length of the rate freeze period created substantial uncertainty as to the ultimate recovery of its costs over the entire freeze period. Consequently, the Company determined that it should not re-apply SFAS No. 71 to its Texas jurisdiction at the time it emerged from bankruptcy in February 1996. As the freeze period draws to a close, the Company will continue to evaluate whether it meets the criteria for the re-application of SFAS No. 71 to its Texas jurisdiction.

During 2004, the Company determined that it met the criteria necessary to re-apply SFAS No. 71 to its New Mexico jurisdictional operations. For the New Mexico jurisdiction, two key events transpired that, when considered together, resulted in the Company's decision to re-apply SFAS No. 71. In April of 2004, the Company received a final order approving a unanimous stipulation which established new base and fuel rates for its New Mexico customers which were implemented June 1, 2004. The Company's approved rates were based upon its cost of providing service in New Mexico. That event, coupled with the repeal of New Mexico's electric utility industry restructuring law which occurred in April of 2003, resulted in the Company meeting the criteria for the re-application of SFAS No. 71 to New Mexico, beginning July 1, 2004. The re-application of SFAS No. 71 to the Company's New Mexico jurisdiction resulted in the recording of $18.5 million of regulatory assets, $5.0 million in related accumulated deferred income tax assets, $16.2 million of regulatory liabilities, $5.5 million in related accumulated deferred tax liabilities and a $1.8 million extraordinary gain, net of tax, or $0.04 basic and diluted earnings per share. The Company's continued ability to meet the criteria for the application of SFAS No. 71 for the New Mexico jurisdiction may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to the New Mexico jurisdiction, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided.

Collection of Fuel Expense

In general, through regulation, the Company's fuel and purchased power expenses are passed through to its customers. These costs are subject to reconciliation by the Texas and New Mexico Commissions. Prior to the completion of a reconciliation, the Company records fuel transactions such that fuel revenues equal fuel expense except for the portion fixed in New Mexico. In the event that a disallowance occurs during a reconciliation proceeding, the amounts recorded for fuel and purchased power expenses could differ from the amounts allowed to be collected by the Company from its customers and the Company could incur a loss to the extent of the disallowance.

Value of Net Utility Plant in Service

In 1996, when it emerged from bankruptcy, the Company recast its financial statements by applying fresh-start reporting in accordance with Statement of Position 90-7 "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code." In this process, the Company attributed value to its integrated utility system, including its generation assets, after it had established the value of its pro forma capital structure based on management's estimates of future operating results. The Company valued its generation assets such that the depreciated value of its generation assets would be approximately equal to their estimated fair value at the end of the Freeze Period. This is important because at the beginning of retail competition in Texas, the Company will no longer be permitted to recover in rates any "stranded costs", that is, the difference between the book value and the market value of its electric generation assets. If at any time the Company determines that estimated, undiscounted future net cash flows from the operations of the generation assets are not sufficient to recover their net book value, then it will be required to write down the value of these assets to their fair values. Any such writedown would be charged to earnings. The Company currently believes that its rates are sufficient to

collect before the expiration of the Freeze Period substantially all costs that would otherwise be "stranded" under relevant laws in Texas and that future net cash flows after the expiration of the Freeze Period from the generating assets will be sufficient to recover their net book values.

Decommissioning Costs and Estimated Asset Retirement Obligation

Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3 and associated common areas. The Company recorded a liability and a corresponding asset for the fair value of its decommissioning obligation (ARO) upon implementation of SFAS No. 143. The Company will adjust the liability to its present value periodically over time, and the corresponding asset will be depreciated over its useful life. The determination of the estimated liability requires the use of various assumptions pertaining to decommissioning costs, escalation and discount rates.

The Company and other Palo Verde Participants rely upon decommissioning cost studies and make discount rate, rate of return and inflation projections to determine funding requirements and estimate liabilities related to decommissioning. Every third year, outside engineers perform a study to estimate decommissioning costs associated with Palo Verde Units 1, 2 and 3 and associated common areas. The Company determines how it will fund its share of those estimated costs by making assumptions about future investment returns and future decommissioning cost escalations. The funds are invested in professionally managed investment trust accounts. The Company is required to establish a minimum accumulation and a minimum funding level in its decommissioning trust accounts at the end of each annual reporting period in accordance with the ANPP Participation Agreement. If actual decommissioning costs exceed estimates, the Company would incur additional costs related to decommissioning. Further, if the rates of return earned by the trusts fail to meet expectations, the Company will be required to increase its funding to the decommissioning trust accounts. Although the Company cannot predict the results of future studies, the Company believes that the liability it has recorded for its decommissioning costs will be adequate to provide for the Company's share of the costs, assuming that Palo Verde Units 1, 2 and 3 operate over their remaining lives (which includes an assessment of the probability of a license extension) and that the DOE assumes responsibility for permanent disposal of spent fuel at plant shut down. The Company believes that its current annual funding levels of the decommissioning trust will adequately provide for the cash requirements associated with decommissioning. Historically, regulated utilities such as the Company have been permitted to collect in rates the costs of nuclear decommissioning. Should the Company become subject to the Texas Restructuring Law, the Company expects to continue to be able to collect from customers the costs of decommissioning.

Future Pension and Other Postretirement Obligations

The Company's obligations to retirees under various benefit plans are recorded as a liability on the consolidated balance sheets. This liability is calculated on the basis of significant assumptions regarding discount rate, expected return on plan assets, rate of compensation increase and health care cost inflation. These assumptions as well as a sensitivity analysis of the effect of hypothetical changes in certain assumptions are set forth in detail in Note K "Employee Benefits" to the Notes to Consolidated Financial Statements. Changes in these assumptions could have a material impact on both net income and on the amount of liabilities reflected on the consolidated balance sheets.

In developing the assumptions, management makes judgments based on the advice of financial and actuarial advisors and its review of third-party and market-based data. These sources include life expectancy tables, surveys of compensation and health care cost trends, and historical and expected return data on various categories of plan assets. The assumed discount rate applied to future plan obligations is based at each measuring date on prevailing market interest rates inherent in high quality (AA and better) corporate bonds that would provide future cash flow needed to pay the benefits as they become due, as well as on publicly available bond issues. The Company regularly reviews its assumptions and conducts a reassessment at least once a year. The Company does not expect that any such change in assumptions will have a material effect on net income for 2005.

Reserves for Tax Dispute

The Company received final approval from the IRS during the third quarter of 2004 to settle all issues relative to its 1996 through 1998 federal income tax returns. As part of the settlement, the Company was required to capitalize (for tax purposes) approximately twenty percent of the previously claimed lease rejection damage deductions. In addition, the IRS conceded the litigation settlement issue related to a terminated merger agreement. As a result of the IRS settlement, the Company reduced its estimated contingent tax liability by $3.5 million related to the resolution of certain tax contingency items and adjusted its state deferred tax liabilities (net of federal tax benefit) by $2.7 million. The IRS settlement reduced income tax expense by approximately $6.2 million during 2004, which increased net income for such period by the same amount. The IRS is currently performing an examination of the 1999 through 2002 income tax returns. The Company has established, and periodically reviews and re-evaluates, an estimated contingent tax liability on its consolidated balance sheet to provide for the possibility of adverse outcomes in tax proceedings. Although the ultimate outcome of the ongoing examination cannot be predicted with certainty, and while the contingent tax liability may not in fact be sufficient, the Company believes that the amount of contingent tax liability recorded as of December 31, 2004 is a reasonable estimate of any additional tax that may be due.

Overview

The Company derives revenue principally from the sale of power to retail and wholesale customers (including economy sales), which accounted for 87% and 11%, respectively, of the Company's revenues for the year ended December 31, 2004, and 87% and 12%, respectively, of the Company's revenues for the year ended December 31, 2003. Revenues from the sale of electricity include fuel costs, which are passed through directly to customers, and base revenues. Base revenues refers to the Company's revenues from the sale of electricity excluding such fuel costs. Economy sales, which are sales into markets outside the Company's service territory, represented 11% and 12% of revenues for the years ended December 31, 2004 and 2003, respectively.

The Company's retail customers consist of residential customers, small commercial and industrial customers, large commercial and industrial customers and public authorities, which accounted for 38%, 36%, 10% and 16%, respectively, of the Company's retail base revenues for the years ended December 31, 2004 and 2003. Sales for resale base revenues consist of sales pursuant to a long-term power contract for the year ended December 31, 2004. For the year ended December 31, 2003, sales for resale base revenues consist of sales pursuant to a long-term power contract and sales to CFE, which accounted for 59% and 41%, respectively, of the Company's sales for resale base revenues. Sales to the

Company's largest wholesale customer, Rio Grande Electric Cooperative, accounted for 0.4% of the Company's base revenues for the years ended December 31, 2004 and 2003. No retail customer accounted for more than 3% of the Company's base revenues during such periods.

The Company's business is seasonal, with higher revenues during the summer cooling season. The following table sets forth the percentage of the Company's revenues derived during each quarter for the periods presented:

	Years Ended December 31,		
	2004	2003	2002
January 1 to March 31	22%	22%	22%
April 1 to June 30	26	24	26
July 1 to September 30	29	30	30
October 1 to December 31	23	24	22
Total	100%	100%	100%

Palo Verde, which represents approximately 40% of the Company's available net generating capacity and approximately 49% of the Company's available energy for the twelve months ended December 31, 2004, is subject to performance standards in Texas. If such performance standards are not met, the Company is subject to a penalty. See "Business–Regulation–Texas Regulatory Matters–Palo Verde Performance Standards."

Historical Results of Operations

	Years Ended December 31,			
	2004	2003	2002	
	Actual	Actual	Actual	Pro forma
Income before extraordinary item and cumulative effect of accounting change (in thousands)	$ 33,369	$ 20,322	$ 28,674	$ 33,297
Diluted earnings per share before extraordinary item and cumulative effect of accounting change	0.69	0.42	0.57	0.66

Income before the extraordinary item and cumulative effect of accounting change increased $13.0 million, or $0.27 diluted earnings per share in 2004 compared to the restated results for 2003. This after-tax increase resulted primarily from (i) the 2003 asset impairment loss of $10.7 million on the Customer Information System ("CIS") project with no comparable loss in the current period; (ii) the recording of the benefits of the IRS settlement of $6.2 million in 2004 with no comparable amounts in 2003; (iii) decreased 2004 non-Palo Verde maintenance expense of $3.3 million; (iv) the Texas fuel disallowance in Docket No. 26194 of $2.8 million that was recorded in 2003 with no comparable amount in the current period; (v) increased 2004 retail sales of $1.9 million; (vi) the extraordinary gain

in 2004 of $1.8 million related to the re-application of SFAS No. 71 to the Company's New Mexico jurisdictional operations; and (vii) a 2003 accrual for a gas contract termination charge of $0.9 million with no comparable amount in the current period. These increases in earnings were partially offset by (i) increased 2004 pensions and benefits expense of $3.8 million (including an employee bonus in 2004 with no comparable amount in 2003); (ii) increased 2004 depreciation and amortization expense of $3.6 million; (iii) increased 2004 loss on extinguishments of debt of $3.3 million; (iv) increased 2004 Palo Verde operations and maintenance expense of $2.6 million (including a Palo Verde employee annual bonus with no comparable amount in 2003); and (v) an increase in the coal reclamation liability in 2004 of $1.5 million.

The pro forma net income and earnings per share amounts shown above assume SFAS No. 143 had been applied on a retroactive basis.

Income before the extraordinary item and cumulative effect of accounting change decreased $13.0 million, or $0.24 diluted earnings per share in 2003 compared to the pro forma results for 2002. This after-tax decrease resulted primarily from (i) decreased 2003 wholesale sales revenue of $17.0 million primarily related to the expiration of two long-term contracts; (ii) the impairment loss on the CIS project of $10.7 million recorded in 2003 with no comparable amount in 2002; (iii) increased 2003 pension and benefits expenses of $3.1 million; (iv) Texas fuel disallowance of $2.8 million recorded in 2003 with no comparable amount in 2002; (v) increased 2003 insurance expenses of $2.8 million; (vi) increased 2003 outside services of $2.2 million; and (vii) increased 2003 expense at Palo Verde of $1.3 million. These decreases were partially offset by (i) the 2002 accrual for the FERC settlements of $9.5 million with no comparable amount in 2003; (ii) increased 2003 sales and margins on economy sales of $6.3 million; (iii) increased 2003 retail sales of $5.6 million; (iv) decreased 2003 interest on long-term debt of $2.3 million; (v) decreased 2003 loss on extinguishments of debt of $2.1 million; and (vi) decreased 2003 MiraSol operating loss of $1.9 million.

Operating revenues net of energy expenses increased $4.4 million in 2004 compared to 2003 primarily due to the Texas fuel disallowance in Docket No. 26194 of $4.5 million that was recorded in 2003 with no comparable amount in the current period and increased 2004 retail sales of $3.1 million, partially offset by an increase of $2.4 million in 2004 coal reclamation liability.

Operating revenues net of energy expenses decreased $16.4 million in 2003 compared to 2002 primarily due to (i) decreased 2003 wholesale sales of $25.5 million; (ii) Texas fuel disallowance of $4.5 million recorded in 2003 with no comparable amount in 2002; and (iii) a 2003 $4.0 million decrease in revenue from the energy service operations partially offset by increased 2003 sales and margins on economy sales of $10.3 million and increased 2003 retail sales of $9.2 million.

Comparisons of kWh sales and operating revenues are shown below (in thousands):

Years Ended December 31:	2004	2003	Increase (Decrease) Amount	Increase (Decrease) Percent	
kWh sales:					
Retail:					
Residential	1,986,085	1,932,171	53,914	2.8%	
Commercial and industrial, small	2,115,822	2,096,860	18,962	0.9	
Commercial and industrial, large	1,236,426	1,197,065	39,361	3.3	
Sales to public authorities	1,243,003	1,224,349	18,654	1.5	
Total retail sales	6,581,336	6,450,445	130,891	2.0	
Wholesale:					
Sales for resale	41,094	67,754	(26,660)	(39.3)	(1)
Economy sales	1,838,467	1,920,882	(82,415)	(4.3)	
Total wholesale sales	1,879,561	1,988,636	(109,075)	(5.5)	
Total kWh sales	8,460,897	8,439,081	21,816	0.3	
Operating revenues:					
Base revenues:					
Retail:					
Residential	$ 174,752	$ 171,459	$ 3,293	1.9%	
Commercial and industrial, small	165,760	165,434	326	0.2	
Commercial and industrial, large	43,150	43,294	(144)	(0.3)	
Sales to public authorities	72,720	73,136	(416)	(0.6)	
Total retail base revenues	456,382	453,323	3,059	0.7	
Wholesale:					
Sales for resale	1,675	3,223	(1,548)	(48.0)	(1)
Total base revenues	458,057	456,546	1,511	0.3	
Fuel revenues	161,052	122,761	38,291	31.2	(2)
Economy sales	78,533	76,536	1,997	2.6	(3)
Other	10,986	8,519	2,467	29.0	(4)(5)
Total operating revenues	$ 708,628	$ 664,362	$ 44,266	6.7	

(1) Primarily due to 2003 CFE wholesale power sales with no comparable sales in 2004.
(2) Primarily due to an increase in recoverable fuel expenses as a result of an increase in the price and volume of natural gas burned and an increase in purchased power costs.
(3) Primarily due to higher margins.
(4) Represents revenues with no related kWh sales.
(5) Primarily due to increased transmission revenues.

Years Ended December 31:	2003	2002	Increase (Decrease) Amount	Percent	
kWh sales:					
Retail:					
Residential	1,932,171	1,870,931	61,240	3.3%	
Commercial and industrial, small	2,096,860	2,076,758	20,102	1.0	
Commercial and industrial, large	1,197,065	1,161,815	35,250	3.0	
Sales to public authorities	1,224,349	1,212,180	12,169	1.0	
Total retail sales	6,450,445	6,321,684	128,761	2.0	
Wholesale:					
Sales for resale	67,754	986,134	(918,380)	(93.1)	(1)
Economy sales	1,920,882	1,483,465	437,417	29.5	(2)
Total wholesale sales	1,988,636	2,469,599	(480,963)	(19.5)	
Total kWh sales	8,439,081	8,791,283	(352,202)	(4.0)	
Operating revenues:					
Base revenues:					
Retail:					
Residential	$ 171,459	$ 166,320	$ 5,139	3.1%	
Commercial and industrial, small	165,434	163,553	1,881	1.2	
Commercial and industrial, large	43,294	43,419	(125)	(0.3)	
Sales to public authorities	73,136	70,802	2,334	3.3	
Total retail base revenues	453,323	444,094	9,229	2.1	
Wholesale:					
Sales for resale	3,223	32,228	(29,005)	(90.0)	(1)
Total base revenues	456,546	476,322	(19,776)	(4.2)	
Fuel revenues	122,761	158,650	(35,889)	(22.6)	(3)
Economy sales	76,536	43,654	32,882	75.3	(2)
Other	8,519	11,459	(2,940)	(25.7)	(4)(5)
Total operating revenues	$ 664,362	$ 690,085	$ (25,723)	(3.7)	

(1) Primarily due to the expiration of a wholesale power contract with IID on April 30, 2002 and TNP on December 31, 2002, and reduced sales to the CFE.
(2) Primarily due to increased available power as a result of the expiration of the wholesale contracts mentioned above and higher prices in the economy market.
(3) Primarily due to the expiration of wholesale power contracts with IID and TNP, decreased energy expenses passed through to Texas and New Mexico customers, and reduced sales to the CFE.
(4) Primarily due to decreased energy services revenues.
(5) Represents revenues with no related kWh sales.

Other operations expense increased $5.5 million in 2004 compared to 2003 primarily due to increased pension and benefits expense of $6.1 million (including a $3.2 million increase in employee bonuses), and increased Palo Verde operations expense of $1.7 million. These increases were partially offset by decreased insurance-related expenses of $1.5 million and decreased customer accounts expense of $1.5 million.

Other operations expense increased $14.6 million in 2003 compared to 2002 primarily due to (i) increased pension and benefits expense of $5.0 million resulting from declines in the financial markets; (ii) accretion expense of $4.8 million related to the implementation of SFAS No. 143; (iii) increased insurance related expenses of $4.5 million; (iv) increased legal and consulting fees of $3.7 million; and (v) increased Palo Verde expense of $3.4 million. These increases were partially offset by decreased energy services operations expense of $7.2 million primarily due to a warranty reserve recorded by the Company in 2002 and the cessation of additional marketing activities by MiraSol in 2002.

The Company abandoned the CIS project and recognized an asset impairment loss of $17.6 million in September 2003. The Company is now analyzing various options to meet its current and projected CIS needs.

The FERC settlements relate to the settlements with the FERC Trial Staff and principal California parties pursuant to which the Company agreed to refund $15.5 million of revenues it earned on wholesale power transactions in 2000 and 2001. These settlements were recorded in December 2002.

Maintenance expense decreased $3.1 million in 2004 compared to 2003 primarily due to a decrease in non-Palo Verde maintenance expense of $5.4 million offset by increased maintenance at Palo Verde of $2.4 million due to the timing of scheduled refueling and maintenance outages.

Maintenance expense increased slightly in 2003 compared to 2002 primarily due to maintenance outages in 2003 at local generating stations of $1.7 million offset by reduced maintenance at Palo Verde of $1.2 million due to the timing of scheduled refueling and maintenance outages.

Depreciation and amortization expense increased $5.8 million in 2004 compared to 2003 primarily due to depreciation on the new Palo Verde Unit 2 steam generators of $2.2 million, the implementation of new depreciation rates based on a new depreciation study resulting in an increase of $1.9 million and increased other depreciable plant balances resulting in an increase of $1.7 million. Depreciation and amortization expense decreased $2.4 million in 2003 compared to 2002 primarily due to decreased depreciation expense of $3.7 million resulting from the adoption of SFAS No. 143.

Taxes other than income taxes remain relatively unchanged in 2004 compared to 2003. Taxes other than income taxes decreased by $0.5 million in 2003 compared to 2002 due to a decrease in property tax.

Other income (deductions) decreased $5.1 million in 2004 compared to 2003 primarily due to (i) losses on extinguishments of debt of $5.4 million recorded in 2004 with no comparable activity in 2003; (ii) $1.1 million reduction in interest income in 2004 associated with the resolution of the Texas fuel reconciliation in PUC Docket No. 26194; and (iii) $1.0 million related to certain tax refunds received in 2003 with no comparable amount in 2004. These decreases were partially offset by an increase of $2.4 million in investment and interest income related to the decommissioning trust fund.

Other income (deductions) increased $6.9 million in 2003 compared to 2002 primarily due to losses on extinguishments of debt of $3.4 million recorded in 2002 with no comparable activity in 2003

and increased investment and interest income of $2.8 million primarily related to the decommissioning trust fund.

Interest charges (credits) decreased slightly in 2004 compared to 2003 primarily due to decreased interest expense of $2.2 million due to a reduction of outstanding debt as a result of open market purchases of the Company's first mortgage bonds partially offset by a reduction in capitalized interest of $2.1 million as a result of transferring Palo Verde Unit 2 steam generators to plant in service. Interest charges decreased $11.8 million in 2003 compared to 2002 primarily due to (i) an $8.3 million decrease resulting from the adoption of SFAS No. 143 and (ii) a $3.5 million decrease resulting from a reduction of outstanding debt as a result of open market purchases of the Company's first mortgage bonds.

Income tax expense, before the tax effect of an extraordinary item, decreased $4.0 million in 2004 compared to 2003 primarily due to the $6.2 million benefit from the IRS settlement offset by changes in pretax income and certain permanent differences and adjustments. Income tax expense, before the tax effect of a cumulative effect of accounting change, decreased $3.3 million in 2003 compared to 2002 primarily due to changes in pretax income and certain permanent differences and adjustments.

Extraordinary gain on re-application of SFAS No. 71 relates to the Company's 2004 third quarter determination that it met the criteria necessary to re-apply SFAS No. 71 to its New Mexico jurisdiction. The decision was based on the Company's receiving the New Mexico Commission's approval for new rates that were based upon the Company's cost of service and the fact that New Mexico had repealed its electric utility restructuring law. The re-application of SFAS No. 71 to the Company's New Mexico jurisdiction resulted in the recording of a $1.8 million extraordinary gain.

The cumulative effect of accounting change relates to the adoption of SFAS No. 143 on January 1, 2003. SFAS No. 143 provides guidance on the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. SFAS No. 143 affected the accounting for the decommissioning of the Company's Palo Verde and Four Corners Stations and changed the method used to report the decommissioning obligation.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs" – an amendment of Accounting Research Bulletin No. 43, ("ARB No. 43"), ("Inventory Pricing"). ARB No. 43 previously stated that "under some circumstances, items such as idle facility expense, excessive spoilage, double freight and rehandling costs may be so abnormal as to require treatment as current period charges." SFAS No. 151 requires that those items be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal." The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe SFAS No. 151 will have a significant impact on the Company's consolidated financial statements.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets" – an amendment of Accounting Principles Board Opinion No. 29 ("APB No. 29"), "Accounting for Nonmonetary Transactions." The guidance in APB No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged, with certain exceptions. SFAS No. 153 eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have

"commercial substance." A nonmonentary exchange has "commercial substance" if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for fiscal periods beginning after June 15, 2005. The Company does not believe SFAS No. 153 will have a significant impact on the Company's consolidated financial statements.

In December 2004, the FASB issued a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 (revised) focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS No. 123 (revised) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with some limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award – "the requisite service period" – typically the vesting period. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. SFAS No. 123 (revised) is effective for public entities that do not file as small business issuers as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. SFAS No. 123 (revised) applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. Additionally, compensation cost for outstanding awards for which the requisite service has not been rendered as of the effective date shall be expensed as the requisite service is rendered on or after the required effective date. The compensation cost for that portion of awards shall be based on the grant-date fair value of those awards as calculated for pro forma disclosure under SFAS No. 123. Due to timing of the release of SFAS No. 123 (revised), the Company has not yet completed the analysis of the ultimate impact that this new pronouncement will have on the Company's financial statements but does not expect this statement to have an effect materially different than the pro forma disclosures provided in Note A to the Company's consolidated financial statements.

Under SFAS No. 71, regulated electric utilities show certain recoverable costs as either assets or liabilities on a utility's balance sheet if the regulator provides assurance that these costs will be charged to and collected from its customers (or has already permitted such cost recovery). The resulting regulatory assets or liabilities are amortized in subsequent periods based upon their respective amortization periods in a utility's cost of service. The Company's Texas jurisdiction has been operating under a rate freeze since August 2, 1995. The rate freeze is for a ten-year period which expires on July 31, 2005. Although the Company believes the rates established in 1995 were based upon its costs of service, the unusual length of the rate freeze period created substantial uncertainty as to the ultimate recovery of its costs over the entire Freeze Period. Consequently, the Company determined that it should not re-apply SFAS No. 71 to its Texas jurisdiction at the time it emerged from bankruptcy in February 1996. As the Freeze Period draws to a close, the Company will continue to evaluate whether it meets the criteria for the re-application of SFAS No. 71 to its Texas jurisdiction.

For the last several years, inflation has been relatively low and, therefore, has had little impact on the Company's results of operations and financial condition.

Liquidity and Capital Resources

The Company's principal liquidity requirements in the near-term are expected to consist of the refinancing of the Company's pollution control bonds and its first mortgage bonds, interest payments on the Company's indebtedness, operating and capital expenditures related to the Company's generating facilities and transmission and distribution systems, and income and other taxes. The Company expects that, for all but the debt refinancing, cash flows from operations will be sufficient for such purposes. As of December 31, 2004, the Company had approximately $29.4 million in cash and cash equivalents, a decrease of $5.0 million from the balance of $34.4 million on December 31, 2003.

The Company's contractual obligations as of December 31, 2004 are as follows (in thousands):

	Payments due by period				
	Total	2005	2006 and 2007	2008 and 2009	2010 and Later
Long-Term Debt (including interest):					
First mortgage bonds	$ 488,330	$ 32,901	$ 212,923 (1)	$ 34,508	$ 207,998
Pollution control bonds	200,289	200,289 (2)	–	–	–
Promissory note	35	35	–	–	–
Financing Obligations (including interest):					
Nuclear fuel (3)	42,558	21,613	20,945	–	–
Purchase Obligations:					
Capacity power contract	273,217	8,409	22,816	23,551	218,441
Fuel contracts:					
Coal (4)	93,737	8,151	16,302	16,302	52,982
Gas (4)	84,176	29,583	54,593	–	–
Nuclear fuel (5)	11,960	10,756	1,204	–	–
Retirement Plans and Other Postretirement Benefits (6)	4,842	4,842	–	–	–
Decommissioning trust funds (7)	272,213	6,169	13,637	15,119	237,288
Operating lease (8)	2,708	1,282	1,426	–	–
Total	$ 1,474,065	$ 324,030	$ 343,846	$ 89,480	$ 716,709

(1) The Company's 8.9% Series D First Mortgage Bonds are due in February 2006.
(2) The pollution control bonds are scheduled for remarketing on August 1, 2005.
(3) Interest on nuclear fuel is based on actual interest rates at the end of 2004.
(4) Amount is based on the minimum volumes per the contract and market price at the end of 2004.
(5) Some of the nuclear fuel contracts are based on a fixed price adjusted for an index. The index used is the current index at the end of 2004.
(6) These obligations include the Company's minimum contractual funding requirements for the non-qualified retirement income plan and the other postretirement benefits for 2005. The Company has no minimum contractual funding requirement related to its retirement income plan for 2005. However, the Company may decide to fund at a higher level than the minimum contractual funding amounts and expects to contribute $18.5 million and $3.4 million to its retirement plans and postretirement benefit plan in 2005, as disclosed in Part II, Item 8, Notes to Financial Statements, Note K, Employee Benefits. Minimum contractual funding requirements for 2006 and beyond are not included due to the uncertainty of interest rates and the related return on assets.
(7) These obligations represent funding requirements under the ANPP Participation Agreement based on the current rate of return on investments.

(8) The Company has an operating lease for administrative offices which expires in May 2007 and a two-year operating lease for a warehouse which expires in January 2006 with two concurrent renewal options of six months each.

Pollution control bonds of $193.1 million are subject to remarketing on August 1, 2005, and first mortgage bonds of $175.8 million are scheduled to mature in 2006. The Company expects that these obligations will be refinanced through the capital and credit markets. Additionally, the Company has $183.6 million of first mortgage bonds which become callable in 2006 and which may be refinanced at that time if market conditions are favorable. The Company's ability to access capital and credit markets may be adversely affected by uncertainties related to its operating results, conditions in the credit markets and debt rating agency actions.

Long-term capital requirements of the Company will consist primarily of construction of electric utility plant and the payment of interest on and retirement and refinancing of debt. Utility construction expenditures will consist primarily of expanding and updating the transmission and distribution systems, addition of new generation, and the cost of capital improvements and replacements at Palo Verde and other generating facilities, including the replacement of steam generators in Palo Verde Units 1 and 3. See Part I, Item 1, "Business – Construction Program."

During the twelve months ended December 31, 2004 and 2003, the Company utilized $74.2 million and generated $0.7 million, respectively, of regular federal tax loss carryforwards. The significant reduction in federal tax loss carryforwards in 2004 was primarily related to the IRS settlement. The Company anticipates that existing regular federal tax loss carryforwards will be fully utilized in 2005 and the Company's cash flow requirements are expected to include greater amounts of cash for income taxes than has existed in recent years.

The Company is continually evaluating its funding requirements related to its retirement plans, other postretirement benefit plans, and decommissioning trust funds. The Company made contributions of $15.7 million and $9.9 million during the twelve months ended December 31, 2004 and 2003, respectively, to its retirement plans. The Company's contributions to its other postretirement benefit plans were $3.4 million for both 2004 and 2003. The Company also contributed $5.9 million and $10.4 million to the decommissioning trust funds during the twelve months ended December 31, 2004 and 2003, respectively.

The $100 million revolving credit facility provides up to $70 million for nuclear fuel purchases. Any amounts not borrowed by the Company for nuclear fuel purchases are available for use for working capital needs. As of December 31, 2004, approximately $41.2 million had been drawn for nuclear fuel purchases. No amounts are currently outstanding on this facility for working capital needs. The revolving credit facility was renewed for a five-year term in December 2004.

Since inception of its deleveraging program in 1996, the Company has repurchased or retired with internally generated cash $586.5 million of first mortgage bonds. First mortgage bonds totaling $36.0 million were repurchased in 2004. Common stock equity as a percentage of capitalization, including current portion of long-term debt and financing obligations, was 47% as of December 31, 2004.

Since the inception of the stock repurchase programs in 1999, the Company repurchased approximately 15.3 million shares in total at an aggregate cost of $175.6 million, including commissions. During 2004, the Company repurchased 294,842 shares of common stock for $4.5 million, including commissions, pursuant to the two million share buyback program authorized by its Board of Directors in February 2004. An additional 1,705,158 shares are authorized to be repurchased under the currently authorized program. No shares were repurchased during the fourth quarter of 2004. The Company may continue making purchases of its stock pursuant to its stock repurchase plan at open market prices and may engage in private transactions, where appropriate. The repurchased shares will be available for issuance under employee benefit and stock option plans, or may be retired.

Off-Balance Sheet Arrangements

The Company has no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Management Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and the receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, the Company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework.

Based on its assessment, management believes that, as of December 31, 2004, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent registered public accounting firm, KPMG LLP, has issued an audit report on management's assessment of the Company's internal control over financial reporting. This report appears on page 47 of this report.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
El Paso Electric Company:

We have audited the accompanying consolidated balance sheets of El Paso Electric Company and subsidiary as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for each of the years in the three-year period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of El Paso Electric Company and subsidiary as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note D to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations in 2003.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of El Paso Electric Company's internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 11, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

El Paso, Texas
March 11, 2005

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
El Paso Electric Company:

We have audited management's assessment, included in the accompanying Management Report on Internal Control Over Financial Reporting appearing on page 44, that El Paso Electric Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commissions (COSO). El Paso Electric Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that El Paso Electric Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. Also, in our opinion, El Paso Electric Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of El Paso Electric Company and subsidiary as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive operations, changes in common stock equity, and cash flows for each of the years in the three-year period ended December 31, 2004, and our report dated March 11, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

El Paso, Texas
March 11, 2005

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS

ASSETS (In thousands)	December 31, 2004	December 31, 2003
Utility plant:		
Electric plant in service	$ 1,839,924	$ 1,788,652
Less accumulated depreciation and amortization	(666,774)	(595,371)
Net plant in service	1,173,150	1,193,281
Construction work in progress	74,853	69,175
Nuclear fuel; includes fuel in process of $7,128 and $6,878, respectively	69,239	70,198
Less accumulated amortization	(34,195)	(33,888)
Net nuclear fuel	35,044	36,310
Net utility plant	1,283,047	1,298,766
Current assets:		
Cash and temporary investments	29,401	34,426
Accounts receivable, principally trade, net of allowance for doubtful accounts of $3,071 and $3,470, respectively	70,710	66,589
Accumulated deferred income taxes	6,509	36,248
Inventories, at cost	25,193	25,321
Undercollection of fuel revenues	19,302	12,399
Income taxes receivables	18,999	22,051
Prepayments and other	7,507	5,139
Total current assets	177,621	202,173
Deferred charges and other assets:		
Decommissioning trust funds	89,363	80,475
Regulatory assets (see Note A)	18,487	–
Other	12,837	15,200
Total deferred charges and other assets	120,687	95,675
Total assets	$ 1,581,355	$ 1,596,614

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands except for share data)	December 31, 2004	2003
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 62,665,550 and 62,487,263 shares issued, and 102,630 and 146,489 restricted shares, respectively	$ 62,768	$ 62,633
Capital in excess of stated value	268,771	264,235
Deferred and unearned compensation	1,127	(878)
Retained earnings	386,110	350,939
Accumulated other comprehensive loss, net of tax	(10,553)	(9,613)
	708,223	667,316
Treasury stock, 15,365,108 and 15,070,266, shares respectively; at cost	(176,076)	(171,548)
Common stock equity	532,147	495,768
Long-term debt, net of current portion	359,362	588,536
Financing obligations, net of current portion	20,274	20,186
Total capitalization	911,783	1,104,490
Current liabilities:		
Current maturities of long-term debt and financing obligations	214,092	22,106
Accounts payable, principally trade	34,404	19,197
Taxes accrued other than federal income taxes	15,719	15,167
Interest accrued	13,609	14,706
Overcollection of fuel revenues	520	10,070
Other	24,726	27,389
Total current liabilities	303,070	108,635
Deferred credits and other liabilities:		
Asset retirement obligation	60,388	55,149
Accumulated deferred income taxes	111,991	144,419
Accrued postretirement benefit liability	98,827	94,510
Accrued pension liability	49,055	53,000
Regulatory liabilities (see Note A)	15,682	–
Other	30,559	36,411
Total deferred credits and other liabilities	366,502	383,489
Commitments and contingencies		
Total capitalization and liabilities	$ 1,581,355	$ 1,596,614

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except for share data)

	Years Ended December 31,		
	2004	2003	2002
Operating revenues	$ 708,628	$ 664,362	$ 690,085
Energy expenses:			
Fuel	194,424	165,367	132,413
Purchased and interchanged power	66,451	55,592	97,825
	260,875	220,959	230,238
Operating revenues net of energy expenses	447,753	443,403	459,847
Other operating expenses:			
Other operations	172,985	167,497	152,917
Impairment loss on CIS project	–	17,576	–
FERC settlements	–	–	15,500
Maintenance	45,190	48,246	48,022
Depreciation and amortization	93,372	87,621	90,062
Taxes other than income taxes	42,584	42,728	43,219
	354,131	363,668	349,720
Operating income	93,622	79,735	110,127
Other income (deductions):			
Investment and interest income (loss), net	3,404	1,840	(990)
Loss on extinguishments of debt	(5,356)	(1)	(3,410)
Miscellaneous other income	275	970	487
Miscellaneous other deductions	(3,102)	(2,466)	(2,682)
	(4,779)	343	(6,595)
Interest charges (credits):			
Interest on long-term debt and financing obligations	49,168	51,400	55,160
Other interest	535	695	8,835
Capitalized interest and AFUDC	(3,427)	(5,572)	(5,641)
	46,276	46,523	58,354
Income before income taxes, extraordinary item and cumulative effect of accounting change	42,567	33,555	45,178
Income tax expense	9,198	13,233	16,504
Income before extraordinary item and cumulative effect of accounting change	33,369	20,322	28,674
Extraordinary gain on re-application of SFAS No. 71, net of tax	1,802	–	–
Cumulative effect of accounting change, net of tax	–	39,635	–
Net income	$ 35,171	$ 59,957	$ 28,674
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 0.70	$ 0.42	$ 0.58
Extraordinary gain on re-application of SFAS No. 71, net of tax	0.04	–	–
Cumulative effect of accounting change, net of tax	–	0.82	–
Net income	$ 0.74	$ 1.24	$ 0.58
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change	$ 0.69	$ 0.42	$ 0.57
Extraordinary gain on re-application of SFAS No. 71, net of tax	0.04	–	–
Cumulative effect of accounting change, net of tax	–	0.81	–
Net income	$ 0.73	$ 1.23	$ 0.57
Weighted average number of shares outstanding	47,426,813	48,424,212	49,862,417
Weighted average number of shares and dilutive potential shares outstanding	48,019,721	48,814,761	50,380,468

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS
(In thousands)

	Years Ended December 31,		
	2004	2003	2002
Net income	$ 35,171	$ 59,957	$ 28,674
Other comprehensive income (loss):			
Minimum pension liability adjustment	(1,413)	(4,234)	(21,148)
Net unrealized gains (losses) on marketable securities:			
Net holding gains (losses) arising during period	351	8,764	(7,657)
Reclassification adjustments for net (gains) losses included in net income	(425)	722	4,245
Total other comprehensive income (loss) before income taxes	(1,487)	5,252	(24,560)
Income tax benefit (expense) related to items of other comprehensive income (loss):			
Minimum pension liability adjustment	532	1,673	8,193
Net unrealized gains (losses) on marketable securities	15	(2,117)	1,194
Total income tax benefit (expense)	547	(444)	9,387
Other comprehensive income (loss), net of tax	(940)	4,808	(15,173)
Comprehensive income	$ 34,231	$ 64,765	$ 13,501

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY
(In thousands except for share data)

	Common Stock		Capital in Excess of Stated Value	Deferred and Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net of Tax	Treasury Stock		Total Common Stock Equity
	Shares	Amount					Shares	Amount	
Balances at December 31, 2001	62,250,297	$ 62,250	$ 257,891	$ (2,041)	$ 262,308	$ 752	11,991,637	$ (134,434)	$ 446,726
Grants of restricted common stock	109,240	109	1,477	(1,586)					–
Deferred compensation-restricted stock				1,865					1,865
Stock awards withheld for taxes	(23,727)	(24)	(312)						(336)
Forfeitures of restricted common stock	(23,349)	(23)	(297)	320					–
Deferred taxes on stock incentive plan			(553)						(553)
Stock options exercised or remeasured	280,000	280	1,966						2,246
Adjustment to federal valuation allowance			2,308						2,308
Net income					28,674				28,674
Other comprehensive loss						(15,173)			(15,173)
Treasury stock acquired, at cost							991,358	(12,875)	(12,875)
Balances at December 31, 2002	62,592,461	62,592	262,480	(1,442)	290,982	(14,421)	12,982,995	(147,309)	452,882
Grants of restricted common stock	63,090	63	661	(724)					–
Deferred compensation-restricted stock				1,288					1,288
Stock awards withheld for taxes	(21,799)	(22)	(209)						(231)
Deferred taxes on stock incentive plan			1,008						1,008
Adjustment to federal valuation allowance			295						295
Net income					59,957				59,957
Other comprehensive income						4,808			4,808
Treasury stock acquired, at cost							2,087,271	(24,239)	(24,239)
Balances at December 31, 2003	62,633,752	62,633	264,235	(878)	350,939	(9,613)	15,070,266	(171,548)	495,768
Grants of restricted common stock	56,413	56	756	(812)					–
Deferred compensation-restricted stock				2,804					2,804
Stock awards withheld for taxes	(12,753)	(12)	(160)						(172)
Forfeitures of restricted common stock	(1,074)	(1)	(12)	13					–
Deferred taxes on stock incentive plan			(409)						(409)
Stock options exercised	91,842	92	981						1,073
Adjustment to federal valuation allowance			3,380						3,380
Net income					35,171				35,171
Other comprehensive loss						(940)			(940)
Treasury stock acquired, at cost							294,842	(4,528)	(4,528)
Balances at December 31, 2004	62,768,180	$ 62,768	$268,771	$ 1,127	$ 386,110	$ (10,553)	15,365,108	$ (176,076)	$ 532,147

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2004	2003	2002
Cash Flows From Operating Activities:			
Net income	$ 35,171	$ 59,957	$ 28,674
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	93,372	87,621	90,062
Impairment loss on CIS project	–	17,576	–
Amortization of nuclear fuel	17,226	16,374	17,968
Cumulative effect of accounting change, net of tax	–	(39,635)	–
Extraordinary gain on the re-application of SFAS No. 71, net of tax	(1,802)	–	–
Deferred income taxes, net	401	10,063	2,328
Loss on extinguishments of debt	5,356	1	3,410
Other amortization and accretion	10,851	7,744	11,703
Other operating activities	(414)	1,432	2,918
Change in:			
FERC settlements payable	–	(15,500)	15,500
Accounts receivable	(4,121)	(1,258)	8,207
Inventories	413	(366)	(357)
Net (under)/overcollection of fuel revenues	(16,453)	16,476	4,727
Prepayments and other	(1,787)	(17,687)	(2,220)
Accounts payable	15,207	(5,702)	273
Taxes accrued other than federal income taxes	552	(2,660)	1,674
Interest accrued	(1,097)	(1,259)	(895)
Other current liabilities	(2,663)	225	4,052
Deferred charges and credits	(6,126)	1,612	2,283
Net cash provided by operating activities	144,086	135,014	190,307
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(72,499)	(77,080)	(65,065)
Cash additions to nuclear fuel	(15,828)	(13,848)	(16,036)
Capitalized interest and AFUDC:			
Utility property, plant and equipment	(3,144)	(5,322)	(5,290)
Nuclear fuel	(283)	(250)	(351)
Decommissioning trust funds:			
Purchases, including funding of $5.9 million, $10.4 million and $5.3 million, respectively	(44,640)	(21,079)	(19,308)
Sales and maturities	36,434	9,384	14,190
Other investing activities	(2,808)	1,467	(469)
Net cash used for investing activities	(102,768)	(106,728)	(92,329)
Cash Flows From Financing Activities:			
Proceeds from exercise of stock options	1,073	–	2,006
Repurchases of common stock	(4,528)	(24,239)	(12,875)
Repurchases of and payments on first mortgage bonds	(41,048)	(39,360)	(36,344)
Pollution control bonds:			
Proceeds	–	–	70,400
Payments	–	–	(70,400)
Nuclear fuel financing obligations:			
Proceeds	17,123	15,169	18,235
Payments	(18,102)	(20,207)	(19,310)
Other financing activities	(861)	(365)	(2,542)
Net cash used for financing activities	(46,343)	(69,002)	(50,830)
Net increase (decrease) in cash and temporary investments	(5,025)	(40,716)	47,148
Cash and temporary investments at beginning of period	34,426	75,142	27,994
Cash and temporary investments at end of period	$ 29,401	$ 34,426	$ 75,142

See accompanying notes to consolidated financial statements.

EL PASO ELECTRIC COMPANY AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

General. El Paso Electric Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. El Paso Electric Company also serves wholesale customers in Texas and periodically in the Republic of Mexico.

Principles of Consolidation. The consolidated financial statements include the accounts of El Paso Electric Company and its wholly-owned subsidiary, MiraSol Energy Services, Inc. ("MiraSol") (collectively, the "Company"). MiraSol, which began operations as a separate subsidiary in March 2001, provided energy efficiency products and services previously provided by the Company's Energy Services Business Group. On July 19, 2002, all sales activities of MiraSol ceased. MiraSol remains a going concern in order to satisfy current contracts and warranty and service obligations on previously installed projects. See Note I. All intercompany transactions and balances have been eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Basis of Presentation. The Company maintains its accounts in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (the "FERC").

Re-application of SFAS No. 71 to New Mexico Jurisdiction. Regulated electric utilities typically prepare their financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Under this accounting standard, certain recoverable costs are shown as either assets or liabilities on a utility's balance sheet if the regulator provides assurance that these costs will be charged to and collected from its customers (or has already permitted such cost recovery). The resulting regulatory assets or liabilities are amortized in subsequent periods based upon their respective amortization periods in a utility's cost of service.

Beginning in 1991, the Company discontinued the application of SFAS No. 71 to its financial statements. This decision was based on the Company's determination that its rates were no longer designed to recover its costs of providing service to customers. Upon emerging from bankruptcy in 1996, the Company again concluded that it did not meet the criteria for applying SFAS No. 71 because of the ten-year rate freeze in Texas and its ongoing intention not to seek changes in its New Mexico rates, which had been established in 1990. Although the Company believes the rates established in 1995 were based upon its costs of service, the unusual length of the rate freeze period created substantial uncertainty as to the ultimate recovery of its costs over the entire freeze period. Consequently, the

Company determined that it should not re-apply SFAS No. 71 to its Texas jurisdiction at the time it emerged from bankruptcy in February 1996. As the freeze period draws to a close, the Company will continue to evaluate whether it meets the criteria for the re-application of SFAS No. 71 to its Texas jurisdiction.

During 2004, the Company determined that it met the criteria necessary to re-apply SFAS No. 71 to its New Mexico jurisdictional operations. For the New Mexico jurisdiction, two key events transpired that, when considered together, resulted in the Company's decision to re-apply SFAS No. 71. In April of 2004, the Company received a final order approving a unanimous stipulation which established new base and fuel rates for its New Mexico customers which were implemented June 1, 2004. The Company's approved rates were based upon its cost of providing service in New Mexico. That event, coupled with the repeal of New Mexico's electric utility industry restructuring law which occurred in April of 2003, resulted in the Company meeting the criteria for the re-application of SFAS No. 71 to New Mexico, beginning July 1, 2004. The re-application of SFAS No. 71 to the Company's New Mexico jurisdiction resulted in the recording of $18.5 million of regulatory assets, $5.0 million in related accumulated deferred income tax assets, $16.2 million of regulatory liabilities, $5.5 million in related accumulated deferred tax liabilities and a $1.8 million extraordinary gain, net of tax, or $0.04 basic and diluted earnings per share. The Company's continued ability to meet the criteria for the application of SFAS No. 71 for the New Mexico jurisdiction may be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that SFAS No. 71 no longer applies to the New Mexico jurisdiction, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided.

Comprehensive Income. Certain gains and losses that are not recognized currently in the consolidated statements of operations are reported as other comprehensive income in accordance with SFAS No. 130, "Reporting Comprehensive Income."

Utility Plant. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging from 5 to 31 years), except for approximately $298 million of reorganization value allocated primarily to net transmission, distribution and general plant in service. This amount is being depreciated on a straight-line basis over the ten-year period of the Texas Rate Stipulation, which ends August 2005. For all other utility plant, Texas and New Mexico depreciation lives are the same.

In conjunction with a certain regulatory filing in the New Mexico jurisdiction, the Company implemented new depreciation rates effective January 1, 2004. The new rates had the effect of increasing depreciation and amortization expense by approximately $1.9 million and decreasing net income, after tax, by approximately $1.2 million or $.03 basic and diluted earnings per share.

The Company charges the cost of repairs and minor replacements to the appropriate operating expense accounts and capitalizes the cost of renewals and betterments. Gains or losses resulting from

retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

The cost of nuclear fuel is amortized to fuel expense on a units-of-production basis. A provision for spent fuel disposal costs is charged to expense based on requirements of the Department of Energy (the "DOE") for disposal cost of approximately one-tenth of one cent on each kWh generated. The Company is also amortizing its share of costs associated with on-site spent fuel storage casks at Palo Verde over the burn period of the fuel that will necessitate the use of the storage casks. See Note C.

Impairment of Long-Lived Assets. In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," long-lived assets, such as property, plant, and equipment and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Capitalized Interest. The Company capitalizes interest cost to construction work in progress and nuclear fuel in process in accordance with SFAS No. 34, "Capitalization of Interest Cost" for its Texas jurisdictional operations. For its New Mexico jurisdictional operations, the Company capitalizes interest and common equity costs to construction work in progress and nuclear fuel in process in accordance with SFAS No. 71. The amount of the equity component of the AFUDC capitalized to construction work in progress was $0.3 million for the year ended December 31, 2004.

Asset Retirement Obligation. Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation ("ARO") associated with long-lived assets included within the scope of SFAS No. 143 is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the statement, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. In January 2003 the Company began recording the increase in the ARO due to the passage of time as an operating expense (accretion expense). See Note D.

Cash and Cash Equivalents. All temporary cash investments with an original maturity of three months or less are considered cash equivalents.

Investments. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair market value and consist primarily of equity securities and municipal, federal and corporate bonds in trust funds established for decommissioning of its interest in Palo Verde. Such marketable securities are classified as "available-for-sale" securities and, as such, unrealized gains and losses are included in accumulated other comprehensive income as a separate component of common stock equity. However, if declines in fair value of marketable securities below original cost basis are determined to be other than temporary, then the declines are reported as losses in the consolidated statement of operations and a new cost basis is established for the affected securities at fair value. See Note M.

Inventories. Inventories, primarily parts, materials, supplies and fuel oil are stated at average cost not to exceed recoverable cost.

Operating Revenues Net of Energy Expenses. The Company accrues revenues for services rendered, including unbilled electric service revenues. Energy expenses are stated at actual cost incurred. The Company's Texas retail customers are presently being billed under a fixed fuel factor approved by the Texas Commission. As of June 2003, the Company's New Mexico retail customers are being billed under a fuel adjustment clause which is adjusted monthly, as approved by the New Mexico Commission in June 2004. The Company's recovery of energy expenses in these jurisdictions is subject to periodic reconciliations of actual energy expenses incurred to actual fuel revenues collected. The difference between energy expenses incurred and fuel revenues charged to the Company's Texas and New Mexico customers, as determined under Texas and New Mexico Commission rules, is reflected as net over/undercollection of fuel revenues in the consolidated balance sheets. See Note B.

Unbilled Revenues. Accounts receivable include accrued unbilled revenues of $18.0 million and $16.5 million at December 31, 2004 and 2003, respectively.

Allowance for Doubtful Accounts. Additions, deductions and balances for allowance for doubtful accounts for 2004, 2003 and 2002 are as follows (in thousands):

	2004	2003	2002
Balance at beginning of year	$ 3,470	$ 3,234	$ 3,525
Additions:			
Charged to costs and expense	1,999	3,096	2,909
Recovery of previous write-offs	1,422	981	835
Uncollectible receivables written off	3,820	3,841	4,035
Balance at end of year	$ 3,071	$ 3,470	$ 3,234

Income Taxes. The Company accounts for federal and state income taxes under the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The Company records a valuation allowance to reduce its deferred tax assets to the extent it is more likely than not that such deferred tax assets will not be realized. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date.

Earnings per Share. Basic earnings per share is computed by dividing net income by the weighted average number of shares outstanding. Diluted earnings per share is computed by dividing net income by the weighted average number of shares and the dilutive impact of the sum of unvested restricted stock and the stock options that were outstanding during the period with the amount of outstanding options calculated by using the treasury stock method.

Stock Options and Restricted Stock. The Company has two stock-based long-term incentive plans and accounts for them under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Stock options have typically been granted with an exercise price equal to fair market value on the date of grant and, accordingly, no compensation expense is recorded by the Company. Restricted stock has been granted at fair market value. Accordingly, the Company recognizes compensation expense by ratably amortizing the fair market value of the restricted stock determined at the date of grant over the restriction period of the grant. If compensation expense for the option portion of the plans had been determined based on the fair value of the option at the grant date and amortized on a straight-line basis over the vesting period, consistent with the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company's net earnings and earnings per share would have been reduced to the pro forma amounts presented below:

	Years Ended December 31,		
	2004	2003	2002
Net income, as reported	$ 35,171	$ 59,957	$ 28,674
Deduct: Compensation expense, net of tax	894	916	1,326
Pro forma net income	$ 34,277	$ 59,041	$ 27,348
Basic earnings per share:			
As reported	$ 0.74	$ 1.24	$ 0.58
Pro forma	0.72	1.22	0.55
Diluted earnings per share:			
As reported	0.73	1.23	0.57
Pro forma	0.71	1.21	0.54

The fair value for these options was estimated at the grant date using the Black-Scholes option pricing model. Weighted average assumptions and grant-date fair value for 2004, 2003 and 2002 are presented below:

	2004	2003	2002
Risk-free interest rate	4.01%	4.13%	5.22%
Expected life, in years	7.3	7.4	10.0
Expected volatility	22.42%	24.72%	26.10%
Expected dividend yield	–	–	–
Fair value per option	$4.87	$4.83	$6.75

Restricted Stock. Restricted stock has been granted at fair market value. Compensation expense for the restricted stock awards is recognized on a fair value basis and is measured by referencing the quoted market price of the shares at the grant date, amortized ratably over the restriction period. Unearned compensation related to restricted stock awards is a reduction of common stock equity and included in deferred and unearned compensation on the Company's consolidated balance sheets.

Performance Shares. Subject to meeting certain performance criteria, performance shares will be granted to certain officers under the Company's existing long-term incentive plan on January 1, 2006 and 2007. The Company currently recognizes the related compensation expense by ratably amortizing the current fair market value of awards that would be granted based on the current performance of the Company over the performance cycles. Consistent with the provisions of APB Opinion No. 25, compensation expense for performance shares will be adjusted for subsequent changes (such as the number of shares to be granted, if any, and the fair market value of the Company's stock) in the expected outcome of the performance-related conditions until the end of the performance cycle. Any such adjustments are accounted for as a change in estimate, and the cumulative effect of the change on current and prior periods is recognized in the period of the change.

Other New Accounting Standards. At January 1, 2004, the Company adopted FASB Interpretation No. 46 ("FIN 46R"), "Consolidation of Variable Interest Entities," which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. As of December 31, 2004, the Company has had no transactions that have established a variable interest entity and the implementation of this standard did not have an impact on the Company's financial position or results of operations.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," was issued in May 2003. This statement established standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. The statement also included required disclosures for financial instruments within its scope. For the Company, the statement was effective as of January 1, 2004. The Company currently does not have

any financial instruments that are within the scope of this statement and the implementation of this standard did not have an impact on the Company's financial statements.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs" – an amendment of Accounting Research Bulletin No. 43 ("ARB No. 43"), ("Inventory Pricing"). ARB No. 43 previously stated that "under some circumstances, items such as idle facility expense, excessive spoilage, double freight and rehandling costs may be so abnormal as to require treatment as current period charges." SFAS No. 151 requires that those items be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal." The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe SFAS No. 151 will have a significant impact on the Company's consolidated financial statements.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets" – an amendment of Accounting Principles Board Opinion No. 29 ("APB No. 29"), "Accounting for Nonmonetary Transactions." The guidance in APB No. 29 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged, with certain exceptions. SFAS No. 153 amends the opinion to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have "commercial substance." A nonmonetary exchange has "commercial substance" if the future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for fiscal periods beginning after June 15, 2005. The Company does not believe SFAS No. 153 will have a significant impact on the Company's consolidated financial statements.

In December 2004, the FASB issued a revision of SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 (revised) focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS No. 123 (revised) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with some limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award – "the requisite service period" – typically the vesting period. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. SFAS No. 123 (revised) is effective for public entities that do not file as small business issuers as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. SFAS No. 123 (revised) applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. Additionally, compensation cost for outstanding awards for which the requisite service has not been rendered as of the effective date shall be expensed as the requisite service is rendered on or after the required effective date. The compensation cost for that portion of awards shall be based on the grant-date fair value of those awards as calculated for pro forma disclosure under SFAS No. 123. Due to timing of the release of SFAS No. 123 (revised), the Company has not yet completed the analysis of the ultimate impact that this new pronouncement will have on the

Company's financial statements but does not expect this statement to have an effect materially different than the pro forma disclosures provided in Note A.

Reclassification. Certain amounts in the consolidated financial statements for 2003 and 2002 have been reclassified to conform with the 2004 presentation.

B. Regulation

General

In 1999, both the Texas and New Mexico legislatures enacted electric utility industry restructuring laws requiring competition in certain functions of the industry and ultimately in the Company's service area. In Texas, the Company has been exempt from the requirements of the Texas Restructuring Law, including utility restructuring and retail competition. The Texas Commission recently adopted a rule that would further delay competition in the Company's Texas service territory until at least the time that an independent regional transmission organization ("RTO") begins operation in its relevant power markets. In April 2003, the New Mexico Restructuring Act was repealed and as a result, the Company's operations in New Mexico will continue to be fully regulated. The Company cannot predict at this time the full effects the repeal of the New Mexico Restructuring Act will have on the Company should it be required to ultimately implement the Texas Restructuring Law.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The FERC has been conducting an investigation into potential manipulation of electricity prices in the western United States during 2000 and 2001. On August 13, 2002, the FERC initiated a Federal Power Act ("FPA") investigation into the Company's wholesale power trading in the western United States during 2000 and 2001 to determine whether the Company and Enron engaged in misconduct and, if so, to determine potential remedies. The Company reached settlements with the FERC and other parties in 2002 and 2003. The Company believes the FERC's order resolved all issues between the FERC and the other parties to this investigation. Under the settlements, the Company agreed to refund $15.5 million and to make wholesale sales pursuant to its cost of service rate authority rather than its market-based rate authority for the period December 1, 2002 through December 31, 2004. This agreement allowed the Company to sell power into wholesale markets at its incremental cost plus $21.11 per MWh. To the extent that wholesale market prices exceeded these agreed upon amounts, the Company lost the opportunity to realize these additional revenues. This provision did not have a significant impact on the Company's revenues through December 31, 2004. The Company's ability to make wholesale sales pursuant to its market-based rate authority was restored on January 1, 2005.

RTOs. FERC's rule ("Order 2000") on RTOs strongly encourages, but does not require, public utilities to form and join RTOs. The Company is an active participant in the development of WestConnect, formerly known as the Desert Southwest Transmission and Reliability Operator. As a

participating transmission owner, the Company will ultimately transfer operational authority of its transmission system to WestConnect subject to receiving any necessary regulatory approvals. On October 10, 2002, FERC issued an order indicating that the Company's WestConnect proposal satisfied, or with certain modifications would satisfy, the FERC requirements for an RTO under Order 2000. WestConnect will continue to work with the FERC and two other proposed RTOs in the west to achieve a seamless market structure. The Company, however, is anticipated to be no more than a 9% participant in WestConnect and cannot control the terms or timing of its establishment. WestConnect will not be operational for several years. The establishment of an independent RTO in the Company's service area is a prerequisite for the Company to be considered part of a Qualified Power Region as defined in the Texas Restructuring Law. The timing of the operations of WestConnect could affect when and whether the Company's Texas service territory is deregulated under the Texas Restructuring Law.

Department of Energy. The DOE regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. The DOE has determined that all such exports over international transmission lines shall be made in accordance with Order No. 888, which established the FERC rules for open access.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See "Facilities – Palo Verde Station – Spent Fuel Storage" for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards. The NRC also has the authority to conduct environmental reviews pursuant to the National Environmental Policy Act.

Texas Regulatory Matters

The rates and services of the Company are regulated in Texas by municipalities and by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services within municipalities in Texas and original jurisdiction over certain other activities of the Company. The decisions of the Texas Commission are subject to judicial review.

Deregulation. The Texas Restructuring Law required certain investor-owned electric utilities to separate power generation activities from transmission and distribution activities by January 1, 2002, and on that date, retail competition for generation services was instituted in some parts of Texas. The Texas Restructuring Law, however, specifically recognized and preserved the Company's Texas Rate Stipulation and Texas Settlement Agreement by, among other things, exempting the Company's Texas service area from retail competition until the end of the Freeze Period. On October 13, 2004, the Texas

Commission approved a rule further delaying retail competition in the Company's Texas service territory. The rule approved by the Texas Commission sets a schedule which identifies various milestones for the Company to reach before competition can begin. The first milestone calls for the development, approval by the FERC, and commencement of independent operation of a RTO, including the development of retail market protocols to facilitate retail competition. The complete transition to retail competition would occur upon the completion of the last milestone which would be the Texas Commission's final evaluation of the market's readiness to offer fair competition and reliable service to all retail customers. The Company believes that adoption of this rule will likely delay retail competition in El Paso for at least several years. There is substantial uncertainty about both the regulatory framework and market conditions that will exist if and when retail competition is implemented in the Company's service territory, and the Company may incur substantial preparatory, restructuring and other costs that may not ultimately be recoverable. There can be no assurance that deregulation would not adversely affect the future operations, cash flows and financial condition of the Company.

Renewables and Energy Efficiency Programs. Notwithstanding the Commission's approval of a rule further delaying competition in the Company's Texas service territory, the Company will become subject to the renewable energy and energy efficiency requirements of the Texas Restructuring Law on January 1, 2006. Under the renewable energy requirements, the Company will have to annually obtain its pro rata share of renewable energy credits as determined by the Texas Commission, based on total Texas retail sales subject to renewable energy credit allocation. The Company's ultimate obligation to obtain renewable energy credits will not be known until January 31 of the year following the compliance year, and it will have until March 31 to obtain, if necessary, and submit to the Texas Commission, sufficient credits. In addition, by January 1, 2007 and January 1, 2008, the Company will be required to fund incentives for energy efficiency savings that will achieve the goal of meeting 5% and 10% of its growth in demand through energy efficiency savings, respectively. Preparatory costs incurred by the Company to meet these requirements will not be recoverable in the Company's Texas service territory prior to the expiration of the Freeze Period.

Termination of Freeze Period. The Freeze Period expires on August 1, 2005. Thereafter, the Company will be subject to traditional cost of service regulation by the Texas cities it serves and by the Texas Commission. Its present rates will stay in effect until changed by a city or the Texas Commission. Any such change would be initiated with either a request by the Company or a complaint by a regulator or customer. Any rate change order would be preceded by discovery and presentation of evidence. Any decision by a city would be subject to appellate review by the Texas Commission. The Company has no present intention to request a base rate change, and no complaints against the Company's base rates are pending.

The end of the Freeze Period may also bring an end to the 50/50 sharing of off-system sales margins between the Company and its customers. The current fuel rule in Texas provides that such margins are to be fully credited to customers.

The Company's ten-year franchise with the City of El Paso ("City") expires on August 1, 2005. The franchise governs the Company's usage of City-owned property, including the payment of franchise fees.

The Company is meeting with the City to discuss the Company's franchise and rate treatment after the expiration of the Freeze Period. The Company is unable to predict the outcome of these discussions.

Fuel. Although the Company's base rates are frozen in Texas pursuant to Texas Commission rules and the Texas Rate Stipulation, the Company can request adjustments to its fuel factor to more accurately reflect projected energy costs associated with providing electricity and seek recovery of past undercollections of fuel revenues, subject to periodic final review by the Texas Commission in fuel reconciliation proceedings.

The Company reconciled its Texas jurisdictional fuel costs for the period January 1, 1999 through December 31, 2001 in PUC Docket No. 26194, and on May 5, 2004, the Texas Commission issued its final order. At issue was the Company's request to recover an additional $15.8 million, before interest, from its Texas customers as a surcharge due to fuel undercollections from January 1999 through December 2001. The Texas Commission disallowed approximately $4.5 million of Texas jurisdictional expenses, before interest, consisting primarily of (i) approximately $4.2 million of purchased power expenses which the Texas Commission characterized as "imputed capacity charges," and (ii) approximately $0.3 million in fees which were deemed to be administrative costs, not recoverable as fuel. This disallowance was recorded as a reduction of fuel revenue during the fourth quarter of 2003. In Texas, capacity charges are not eligible for recovery as fuel expenses but are to be recovered through the Company's base rates. As the Company's base rates were frozen during the period in which the imputed capacity charges were deemed to have been incurred, the $4.2 million of imputed capacity charges were therefore permanently disallowed, and not recoverable from its Texas customers. The Texas Commission's decision has been appealed by two parties and the Company, and the Company is unable to predict the ultimate outcome of the appeals.

The Company has incurred similar purchased power costs for the fuel reconciliation period beginning January 1, 2002. The Company believes that it has accounted for its purchased power costs during the reconciliation period beginning January 2002 in a manner consistent with the Texas Commission's decision in PUC Docket No. 26194. However, the Texas Commission recently commenced a generic rulemaking proceeding to determine a statewide policy for the appropriate pricing of capacity in purchased power contracts. On August 31, 2004, the Company filed an application (PUC Docket No. 30143) to reconcile Texas jurisdictional fuel costs for the period January 1, 2002 to February 29, 2004. There can be no assurance as to the outcome of the rulemaking and its potential impact on the Company with respect to fuel recovery in future reconciliation periods, including those in PUC Docket No. 30143.

Palo Verde Performance Standards. The Texas Commission established performance standards for the operation of Palo Verde pursuant to which each Palo Verde unit is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission can also reconsider the rate treatment of Palo Verde, regardless of the provisions of the Texas Rate Stipulation and the Texas Settlement Agreement. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Under the performance standards as modified by the Texas Fuel Settlement, the Company has calculated the performance rewards for the reporting periods ending in 2004, 2003 and 2002 to be approximately $0.2 million, $0.8 million and $1.3 million, respectively. These rewards will be included, along with energy costs incurred and revenues billed, as part of the Texas Commission's review during a future periodic fuel reconciliation proceeding as discussed above. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel proceeding or comparable evidence of collectibility is obtained. Performance penalties are recorded when assessed as probable by the Company.

New Mexico Regulatory Matters

The New Mexico Commission has jurisdiction over the Company's rates and services in New Mexico and over certain other activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. The largest city in the Company's New Mexico service territory is Las Cruces.

Deregulation. In April 2003, the New Mexico Restructuring Act was repealed, and as a result, the Company's operations in New Mexico will continue to be fully regulated. The Company cannot predict at this time the full effects the repeal of the New Mexico Restructuring Act will have on the Company if it ultimately transitions to retail competition in Texas.

New Mexico Rate Stipulation. On June 1, 2004, the Company implemented new rates according to the New Mexico Stipulation whereby, among other things, the Company agreed for a period of three years beginning June 1, 2004 to (i) freeze base rates after an initial non-fuel base rate reduction of 1%; (ii) fix fuel and purchased power cost associated with 10% of the Company's jurisdictional retail sales in New Mexico at $0.021 per kWh; (iii) leave subject to reconciliation the remaining 90% of the Company's New Mexico jurisdictional fuel and purchased power costs not collected in base rates; (iv) continue the collection of a portion of fuel and purchased power costs in base rates as presently collected in the amount of $0.01949 per kWh; (v) price power provided from Palo Verde Unit 3 to the extent of its availability at an 80% nuclear, 20% gas fuel mix; and (vi) deem reconciled, for the period June 15, 2001 through May 31, 2004, the Company's fuel and purchased power costs for the New Mexico jurisdiction.

Fuel. In April 2004, the New Mexico Commission, as part of the New Mexico Stipulation, approved a fuel and purchased power cost adjustment clause. The Company will continue to recover fuel and purchased power costs in base rates in the amount of $0.01949 per kWh and continue the fuel and purchased power cost adjustment to recover 90% of the remaining fuel and purchased power costs. Fuel and purchased power costs associated with the remaining 10% of the Company's jurisdictional retail sales in New Mexico are fixed at $0.021 per kWh. The Company and all intervenors entered into the New Mexico Stipulation on the Company's compliance filing.

Renewables. The New Mexico Renewable Energy Act of 2004 requires that, by January 1, 2006, renewable energy comprise no less than 5% of the Company's total retail sales to New Mexico customers. The requirement increases by 1% annually until January 1, 2011, when the renewable portfolio standard shall reach a level of 10% of the Company's total retail sales to New Mexico customers and will remain fixed at such level thereafter. On September 1, 2004, the Company filed its Transitional Procurement Plan detailing its proposed actions to comply with the Renewable Energy Act.

The New Mexico Commission approved the Company's Transitional Procurement Plan with modifications to shorten the term for the Company's proposed contract to purchase renewable energy credits and to address diversity provisions of the Renewable Energy Act. These modified provisions will be incorporated into the renewable procurement plan to be filed by the Company no later than September 1, 2005 for the 2006 year. Costs incurred by the Company to meet the requirements of the New Mexico Renewable Energy Act are to be recovered from New Mexico customers pursuant to the Renewable Energy Act and the New Mexico Commission's rules.

Sales for Resale

The Company provides up to 10 MW of firm capacity, associated energy, and transmission service to the Rio Grande Electric Cooperative pursuant to an ongoing contract which requires a two-year notice to terminate. No such notice has been received.

C. Utility Plant, Palo Verde and Other Jointly-Owned Utility Plant

The table below presents the balance of each major class of depreciable assets at December 31, 2004 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear Production	$ 596,371	$ (121,563)	$ 474,808
Steam and Other	259,400	(119,543)	139,857
Total Production	855,771	(241,106)	614,665
Transmission	342,307	(197,474)	144,833
Distribution	556,013	(203,163)	352,850
General	71,781	(22,807)	48,974
Intangible and Other	14,052	(2,224)	11,828
Total	$ 1,839,924	$ (666,774)	$ 1,173,150

Amortization of intangible plant (software) is provided on a straight-line basis over the estimated useful life of the asset (ranging from 3 to 10 years). The amortization expense for intangible plant in 2004 was $0.9 million. The table below presents the estimated amortization expense for the next five years (in thousands):

2005	$ 1,560
2006	1,427
2007	1,273
2008	958
2009	825

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: Arizona Public Service Company ("APS"), Southern California Edison Company ("SCE"), Public Service Company of New Mexico ("PNM"), Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde. The operation of Palo Verde and the relationship among the Palo Verde Participants is governed by the Arizona Nuclear Power Project Participation Agreement (the "ANPP Participation Agreement").

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The Company's share of direct expenses in Palo Verde and other jointly-owned utility plants is reflected

in fuel expense, other operations expense, maintenance expense, miscellaneous other deductions, and taxes other than income taxes in the Company's consolidated statements of operations. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant. Because it is impracticable to predict defaulting participants, the Company cannot estimate the maximum potential amount of future payment, if any, which could be required under this provision.

Other jointly-owned utility plant includes a 7% interest in Units 4 and 5 at Four Corners Generating Station ("Four Corners") and certain other transmission facilities. A summary of the Company's investment in jointly-owned utility plant, excluding fuel, at December 31, 2004 and 2003 is as follows (in thousands):

	December 31, 2004		December 31, 2003	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$ 596,371	$ 186,838	$ 588,071	$ 187,036
Accumulated depreciation	(121,563)	(124,146)	(108,765)	(113,845)
Construction work in progress	32,385	4,177	23,251	2,729
Total	$ 507,193	$ 66,869	$ 502,557	$ 75,920

Palo Verde

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company's decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS.

In accordance with the ANPP Participation Agreement, the Company is required to establish a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company remained above its minimum funding level as of December 31, 2004. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

The Company has established external trust with independent trustees, which enable the Company to record a current deduction for federal income tax purposes of a portion of amounts funded. As of December 31, 2004 and 2003, the fair market value of the trust funds was approximately $89.4 million and $80.5 million, respectively, which is reflected in the Company's consolidated balance sheets in deferred charges and other assets.

In August 2002, the Palo Verde Participants approved the 2001 Palo Verde decommissioning study. Some changes in the cost calculations occurred between the prior 1998 study and the 2001 study. The 2001 study estimated that the Company must fund approximately $311.6 million (stated in 2001 dollars) to cover its share of decommissioning costs. The previous cost estimate from the 1998 study estimated that the Company needed to fund approximately $280.5 million (stated in 1998 dollars). The 2001 estimate reflects an 11.1% increase, or 3.6% average annual compound increase, from the 1998 estimate primarily due to increases in estimated costs for site restoration at each unit, pre and post-shutdown transitioning and decommissioning preparations, spent fuel storage after operations have ceased and the Unit 2 steam generator storage. The decommissioning study is stated in 2001 dollars and makes no inflation assumptions. See "Spent Fuel Storage" below.

Although the 2001 study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject to significant uncertainty. The decommissioning study is updated every three years. The 2004 study is expected to be complete in the second quarter of 2005. See "Disposal of Low-Level Radioactive Waste" below.

Historically, regulated utilities such as the Company have been permitted to collect in rates the costs of nuclear decommissioning. The Company, through an affiliated transmission and distribution utility, will be able to continue to collect from customers the costs of decommissioning if and when it becomes subject to the Texas Restructuring Law. The collection mechanism utilized in Texas is a "non-bypassable wires charge" through which all customers, even those who choose to purchase energy from a supplier other than the Company's retail affiliate, will be required to pay a fee, which includes the cost of nuclear decommissioning, to the Company's affiliated transmission and distribution utility. In the Company's case, collection of the fee through the Company's transmission and distribution utility will begin in Texas if and when retail competition is implemented in the Company's Texas service territory. See "Regulation – Texas Regulatory Matters – Deregulation" for further discussion.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which are stored at the new facilities until it is accepted by the DOE for permanent disposal. The 2001 decommissioning study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2037. APS believes that spent fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive

waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation until 2010. Subsequent judicial decisions required the DOE to start accepting spent nuclear fuel by January 31, 1998. The DOE did not meet that deadline, and the Company cannot currently predict when spent fuel shipments to the DOE's permanent disposal site will commence.

The Company expects to incur significant on-site spent fuel storage costs during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs will be amortized over the burn period of the fuel that will necessitate the use of the alternative on-site storage facilities until an agreement is reached with the DOE for recovery of these costs. In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. The Company is unable to predict the outcome of these matters at this time.

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Palo Verde is projected to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact. The opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

Steam Generators. Palo Verde has experienced degradation in the steam generator tubes of each unit. The projected service lives of the Palo Verde steam generators are reassessed by APS periodically in conjunction with inspections made during scheduled outages at the Palo Verde units. New steam generators were installed at Unit 2 during 2003 at a total cost to the Company of approximately $45.4 million. This replacement was based on an analysis of the net economic benefit from expected improved performance of the unit and the need to realize continued production from that unit over its full licensed life.

APS has identified accelerated degradation in the steam generator tubes in Units 1 and 3 and has concluded that it is economically desirable to replace the steam generators at those units. The eventual total project cash expenditures for steam generator replacements for Units 1, 2 and 3 are currently estimated to be $724.0 million excluding replacement power costs (the Company's portion being $114.4 million). As of December 31, 2004, the Company has paid approximately $59.0 million of such

costs. The remaining balance is expected to be paid over the course of the steam generator replacements. The Company expects its portion will be funded with internally generated cash.

The Texas Rate Stipulation precludes the Company from seeking a rate increase to recover additional capital costs incurred at Palo Verde during the Freeze Period. The Company cannot assure that its wholesale power rates and its competitive retail rates will be sufficient to recover its costs when or if retail competition for generation services begins. See also Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview."

Liability and Insurance Matters. In 1957, Congress enacted the Price-Anderson Act as an amendment to the Atomic Energy Act of 1954 to provide a system of financial protection for persons who may be injured or persons who may be liable for a nuclear incident. The Price-Anderson Act expired on December 31, 2003. Existing licensees, such as the Company, are grandfathered and will continue to be subject to the provisions of the Price-Anderson Act in the event Congress does not reauthorize the Price-Anderson Act. Despite extensive debate, the 108th Congress adjourned without passing comprehensive energy legislation which would have extended the Price-Anderson Act. While introduction of energy legislation in the 109th Congress is pending, it remains unclear what its course may be. Proposals to separate less controversial provisions such as the reauthorization of the Price-Anderson Act from the comprehensive legislation were resisted by the House and Senate leadership.

Current versions of energy omnibus legislation, if passed, would provide for the reauthorization of the Price-Anderson Act, thus amending the Atomic Energy Act to: (i) increase from $63 million to $95.8 million the maximum amount of standard deferred premiums charged a licensee following any nuclear incident under an industry retrospective rating plan and (ii) increase from $10 million to $15 million (adjusted for inflation) in any one year the maximum amount of such premiums for each facility for which the licensee must maintain the maximum amount of primary financial protection. The aggregate amount of DOE indemnification currently available to all licensees under the Price-Anderson Act is $9.4 billion. Additionally, the Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability under the Price-Anderson Act. The insurance consists of $200 million of primary liability insurance provided by commercial insurance carriers, with the balance being provided by an industry-wide retrospective assessment program, pursuant to which industry participants would be required to pay a retrospective assessment to cover any loss in excess of $200 million. Presently, the maximum retrospective assessment per reactor for each nuclear incident is approximately $88.1 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential retrospective assessment per incident is approximately $41.8 million for all three units with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company also has

obtained insurance against a portion of any increased cost of generation or purchased power which may result from an accidental outage of any of the three Palo Verde units if the outage exceeds 12 weeks.

D. Accounting for Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The adoption of SFAS No. 143 primarily affected the accounting for the decommissioning of the Company's Palo Verde and Four Corners Stations and changed the method used to report the decommissioning obligation. Upon emergence from bankruptcy in 1996, the Company was required under fresh-start reporting to adopt the concepts of an early exposure draft of the SFAS No. 143 project and accordingly, recognized the present value of its projected Palo Verde asset retirement costs as both a component of its capitalized cost of Palo Verde and as a decommissioning liability. Beginning in 1996 and through 2002, the Company recognized accretion of the Palo Verde ARO liability as a component of interest expense and depreciation of the Palo Verde asset retirement cost as depreciation expense in its consolidated financial statements. Upon adoption of SFAS No. 143, the net difference between the amounts determined under SFAS No. 143 and the Company's previous method of accounting for such activities was recognized as a decrease in the ARO of $95.5 million, a decrease in net plant in service of $30.9 million, and a cumulative effect of accounting change of $39.6 million, net of related taxes of $25.0 million. The cumulative effect of accounting change is primarily due to two factors: (i) using a longer discount period (i.e., longer remaining life) as a result of assessing the probability of a license extension at Palo Verde and (ii) a change in the discount rate used. In January 2003, the Company began recording the increase in the ARO due to the passage of time as an operating expense (accretion expense). As the DOE assumes responsibility for the permanent disposal of spent fuel, spent fuel costs have not been included in the ARO calculation. The Company has six external trust funds with independent trustees which are legally restricted to settling its ARO at Palo Verde. The fair value of the fund at December 31, 2004 is $89.4 million.

A reconciliation of the Company's ARO liability for Palo Verde and Four Corners Stations is as follows (in thousands):

	Years Ended December 31,	
	2004	2003
ARO liability at beginning of year	$ 55,149	$ 50,364
Liabilities incurred	–	–
Liabilities settled	–	–
Revisions to estimate	–	–
Accretion expense	5,239	4,785
ARO liability at end of year	$ 60,388	$ 55,149

The Company has transmission and distribution lines which are operated under various property easement agreements. If the easements were to be released, the Company may have a legal obligation to remove the lines; however, the Company has assessed the likelihood of this occurring as remote. The majority of these easements include renewal options which the Company routinely exercises. Additionally, the Company has certain components of its local generating stations which may result in an ARO. However, substantial uncertainty exists surrounding the ultimate removal date for these facilities. Due to the nature of these assets and the uncertainty of final removal timing and costs, an ARO has not been included for these assets as the ARO cannot be reasonably estimated at this time.

Amounts recorded under SFAS No. 143 are subject to various assumptions and determinations such as (i) whether a legal obligation exists to remove assets; (ii) estimation of the fair value of the costs of removal; (iii) when final removal will occur; (iv) future changes in decommissioning cost escalation rates; and (v) the credit-adjusted interest rates to be utilized in discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as an expense for AROs. If the Company incurs or assumes any liability in retiring any asset at the end of its useful life without a legal obligation to do so, it will record such retirement costs as incurred.

The Company's most recent Palo Verde decommissioning study, completed in 2001, estimated that the Company's share of Palo Verde decommissioning costs would be approximately $311.6 million, in year 2001 dollars. This estimated liability differs from the ARO liability of $60.4 million recorded by the Company as of December 31, 2004. This difference can be attributed to how SFAS No. 143 measures the ARO liability, relative to current cost estimates, and the inherent assumption in SFAS No. 143 that Palo Verde will operate until the end of its useful life (which includes an assessment of the probability of a license extension). The ARO liability calculation begins with the same current cost estimate referenced above, then escalates that cost over the remaining life of the plant, finally discounting the resulting cost at a credit-risk adjusted discount rate. Since the Company assumed an escalation rate of 3.6% and a credit-risk adjusted discount rate of 9.5% in its calculation of the ARO liability, the ARO liability is significantly less than the Company's share of the current estimated cost to decommission Palo Verde in 2001 dollars. As Palo Verde approaches the end of its estimated useful life, the difference between the ARO liability and future current cost estimates will narrow over time due to the accretion of the ARO liability.

E. Common Stock

Overview

The Company's common stock has a stated value of $1 per share, with no cumulative voting rights or preemptive rights. Holders of the common stock have the right to elect the Company's directors and to vote on other matters.

Long-Term Incentive Plans

The Company shareholders have approved the adoption of two stock-based long-term incentive plans. The first plan was approved in 1996 (the "1996 Plan") and authorized the issuance of up to 3.5 million shares of common stock for the benefit of officers, key employees and directors. The second plan was approved in 1999 (the "1999 Plan") and authorized the issuance of up to two million shares of common stock for the benefits of directors, officers, managers, other employees and consultants. The common stock may be issued through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock and performance stock.

Stock Options. Stock options have been granted at exercise prices equal to or greater than the market value of the underlying shares at the date of grant. The options expire ten years from the date of grant unless terminated earlier by the Board of Directors. The following table summarizes the transactions of the Company's stock options for 2004, 2003 and 2002:

	Number of Shares	Weighted Average Exercise Price
Unexercised options outstanding at December 31, 2001	2,255,480	$ 9.64
Options granted	257,257	13.39
Options exercised	(280,000)	8.02
Options forfeited	(20,000)	8.75
Unexercised options outstanding at December 31, 2002	2,212,737	10.40
Options granted	108,717	12.67
Options forfeited	(150,000)	12.60
Unexercised options outstanding at December 31, 2003	2,171,454	10.36
Options granted	3,520	13.64
Options exercised	(91,842)	11.69
Options forfeited	(2,184)	15.87
Unexercised options outstanding at December 31, 2004	2,080,948	10.40

Stock option awards provide for vesting periods of up to six years. Stock options outstanding and exercisable at December 31, 2004 are set forth in the following table:

	Options Outstanding			Options Exercisable	
Exercise Price Range	Number Outstanding	Average Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$ 5.56 - $ 8.125	950,000	2.0	$ 6.73	950,000	$ 6.73
9.50 - 13.85	580,948	7.1	12.72	252,948	12.22
13.94 - 14.95	550,000	6.7	14.28	270,000	14.33
	2,080,948			1,472,948	

The number of stock options exercisable and the weighted average exercise price of these stock options are as follows:

	December 31,		
	2004	2003	2002
Number of stock options exercisable	1,472,948	1,325,454	1,183,737
Weighted average exercise price	$ 9.07	$ 8.36	$ 8.04

Restricted Stock. The Company has awarded vested and unvested restricted stock awards under the 1996 and 1999 Plans. Restrictions from resale generally lapse, and unvested awards vest, over periods of three to five years. The market value of vested restricted stock awards is expensed at the time of grant. The market value of the unvested restricted stock at the date of grant is recorded as deferred and unearned compensation and is shown as a separate component of common stock equity and is amortized to expense over the restriction period. During 2004, 2003 and 2002, approximately $1.2 million, $1.3 million and $1.9 million, respectively, related to restricted stock awards was charged to expense. The following table summarizes the vested and unvested restricted stock awards for 2004, 2003 and 2002:

	Vested	Unvested	Total
Restricted shares outstanding at December 31, 2001	–	267,334	267,334
Restricted stock awards	10,420	98,820	109,240
Lapsed restrictions and vesting	(10,420)	(139,759)	(150,179)
Forfeitures	–	(23,349)	(23,349)
Restricted shares outstanding at December 31, 2002	–	203,046	203,046
Restricted stock awards	–	63,090	63,090
Lapsed restrictions and vesting	–	(119,647)	(119,647)
Restricted shares outstanding at December 31, 2003	–	146,489	146,489
Restricted stock awards	–	84,963	84,963
Lapsed restrictions and vesting	–	(99,198)	(99,198)
Forfeitures	–	(1,074)	(1,074)
Restricted shares outstanding at December 31, 2004	–	131,180	131,180

The weighted average market values at grant date for restricted stock awarded during 2004, 2003 and 2002 are $14.60, $11.47 and $14.52, respectively.

The holder of a restricted stock award has rights as a shareholder of the Company, including the right to vote and, if applicable, receive cash dividends on restricted stock, except that certain restricted stock awards require any cash dividend on restricted stock to be delivered to the Company in exchange for additional shares of restricted stock of equivalent market value.

Performance Shares. On January 1, 2006 and 2007, subject to meeting certain performance criteria, performance shares will be granted to certain officers under the Company's existing long-term incentive plan. The Company currently recognizes the related compensation expense by ratably amortizing the current fair market value of awards that would be granted based on the current performance of the Company over the performance cycles. Consistent with the provisions of APB Opinion No. 25, compensation expense for performance shares will be adjusted for subsequent changes (such as the number of shares to be granted, if any, and the fair market value of the Company's stock) in the expected outcome of the performance-related conditions until the end of the performance cycle. Any such adjustments are accounted for as a change in estimate, and the cumulative effect of the change on current and prior periods is recognized in the period of the change. The actual number of shares granted can range from zero to 198,000 shares. During 2004, $1.6 million related to performance stock awards was charged to expense.

Common Stock Repurchase Program

Since the inception of the stock repurchase programs in 1999, the Company has repurchased approximately 15.3 million shares in total at an aggregate cost of $175.6 million, including commissions, pursuant to the two million share buyback program authorized by its Board of Directors in February 2004. During 2004, the Company repurchased 294,842 shares of common stock for $4.5 million, including commissions, pursuant to the two million share buyback program authorized by its Board of Directors in February 2004. An additional 1,705,158 shares are authorized to be repurchased under the currently authorized program. No shares were repurchased during the fourth quarter of 2004. The Company may continue making purchases of its stock pursuant to its stock repurchase plan at open market prices and may engage in private transactions, where appropriate. The repurchased shares will be available for issuance under employee benefit and stock option plans, or may be retired.

Reconciliation of Basic and Diluted Earnings Per Share

The reconciliation of basic and diluted earnings per share before extraordinary item and cumulative effect of accounting change is presented below:

	Year Ended December 31, 2004		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 33,369	47,426,813	$ 0.70
Effect of dilutive securities:			
Unvested restricted stock	–	84,933	
Stock options	–	507,975	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 33,369	48,019,721	$ 0.69

	Year Ended December 31, 2003		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 20,322	48,424,212	$ 0.42
Effect of dilutive securities:			
Unvested restricted stock	–	51,809	
Stock options	–	338,740	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 20,322	48,814,761	$ 0.42

	Year Ended December 31, 2002		
	Income (In thousands)	Shares	Per Share
Basic earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 28,674	49,862,417	$ 0.58
Effect of dilutive securities:			
Unvested restricted stock.....	–	77,890	
Stock options	–	440,161	
Diluted earnings per share:			
Income before extraordinary item and cumulative effect of accounting change..	$ 28,674	50,380,468	$ 0.57

Options excluded from the computation of diluted earnings per share because the exercise price was greater than the average market price for the periods presented are as follows:

	Years Ended December 31,		
	2004	2003	2002
Options excluded.....	178,845	1,029,411	633,588
Exercise price range	$ 13.77- $15.99	$11.00 - $15.99	$11.19 - $15.99

F. Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consists of the following components (in thousands):

	Net Unrealized Gains (Losses) on Marketable Securities	Minimum Pension Liability Adjustments	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2001	$ 1,263	$ (511)	$ 752
Other comprehensive loss	(3,412)	(21,148)	(24,560)
Income tax benefit	1,194	8,193	9,387
Balance at December 31, 2002	(955)	(13,466)	(14,421)
Other comprehensive income (loss)	9,486	(4,234)	5,252
Income tax (expense) benefit	(2,117)	1,673	(444)
Balance at December 31, 2003	6,414	(16,027)	(9,613)
Other comprehensive loss	(74)	(1,413)	(1,487)
Income tax benefit	15	532	547
Balance at December 31, 2004	$ 6,355	$ (16,908)	$ (10,553)

G. Long-Term Debt and Financing Obligations

Outstanding long-term debt and financing obligations are as follows:

	December 31, 2004	December 31, 2003
	(In thousands)	
Long-Term Debt:		
First Mortgage Bonds (1):		
8.90% Series D, issued 1996, due 2006	$ 175,807	$ 186,182
9.40% Series E, issued 1996, due 2011	183,555	209,184
Pollution Control Bonds (2):		
6.375% 1994 Series A bonds, due 2014	63,500	63,500
6.375% 1985 Series A refunding bonds, due 2015	59,235	59,235
6.250% 2002 Series A refunding bonds, due 2037	37,100	37,100
6.375% 2002 Series A refunding bonds, due 2032	33,300	33,300
Promissory note, due 2005 (3)	35	151
Total long-term debt	552,532	588,652
Financing Obligations:		
Nuclear fuel ($20,922 due in 2005) (4)	41,196	42,176
Total long-term debt and financing obligations	593,728	630,828
Current Maturities (amount due within one year)	(214,092)	(22,106)
	$ 379,636	$ 608,722

(1) First Mortgage Bonds

Substantially all of the Company's utility plant is subject to liens under the First Mortgage Indenture. The First Mortgage Indenture imposes certain limitations on the ability of the Company to (i) declare or pay dividends on common stock; (ii) incur additional indebtedness or liens on mortgaged property and (iii) enter into a consolidation, merger or sale of assets.

The Series D bonds may not be redeemed by the Company prior to maturity. The Series E bonds may be redeemed at the option of the Company, in whole or in part, at 104.70% of par value beginning February 1, 2006, 102.35% of par value beginning February 1, 2007, and at par value beginning February 1, 2008. The Company is not required to make mandatory redemption or sinking fund payments with respect to the bonds prior to maturity.

Repurchases, excluding repayment upon maturity, of First Mortgage Bonds made during 2004, 2003 and 2002 are as follows (in thousands):

	Years Ended December 31,		
	2004	2003	2002
8.25% Series C	$ –	$ 3,278	$ 3,553
8.90% Series D	10,375	–	20,500
9.40% Series E	25,629	–	9,150
Total	$ 36,004	$ 3,278	$ 33,203

Internally generated funds were used for the above repurchases. Losses of $5.4 million and $3.4 million were recorded in 2004 and 2002, respectively, relating to these repurchases and include premiums paid and unamortized issuance costs.

(2) Pollution Control Bonds

The Company has four series of tax exempt Pollution Control Bonds in an aggregate principal amount of approximately $193.1 million. Upon the occurrence of certain events, which includes the remarketing of the bonds, the bonds may be required to be repurchased at the holder's option or are subject to mandatory redemption. All of the pollution control bonds are classified as current maturities at December 31, 2004 since they are within one year of being remarketed. The interest rates will remain at their current fixed interest rates until remarketing in August 2005.

(3) Promissory Note

The note has an annual interest rate of 5.5%, is secured by certain furniture and fixtures and is due in 2005.

(4) Nuclear Fuel Financing

The Company has available a $100 million credit facility that was renewed for a five-year term in December 2004. The credit facility provides for up to $70 million for the financing of nuclear fuel, which is accomplished through a trust that borrows under the facility to acquire and process the nuclear fuel. The Company is obligated to repay the trust's borrowings with interest and has secured this obligation with Collateral Series First Mortgage Bonds. In the Company's financial statements, the assets and liabilities of the trust are reported as assets and liabilities of the Company. Any amounts not borrowed by the trust may be borrowed by the Company for working capital needs.

The $100 million credit facility requires compliance with certain total debt and interest coverage ratios. The Company was in compliance with these requirements throughout 2004. No amounts are currently outstanding on this facility for working capital needs.

As of December 31, 2004, the scheduled maturities for the next five years of long-term debt and financing obligations are as follows (in thousands):

2005	$ 193,170
2006	175,807
2007	–
2008	–
2009	–

The table above does not reflect future obligations and maturities related to nuclear fuel purchase commitments.

H. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2004 and 2003 are presented below (in thousands):

	December 31,	
	2004	2003
Deferred tax assets:		
Alternative minimum tax credit carryforward	$ 51,503	$ 32,555
Pensions and benefits	55,248	55,140
Benefits of federal tax loss carryforwards	682	26,650
Asset retirement obligation	21,136	19,302
Investment tax credit carryforward	5,579	4,570
Other	5,136	7,186
Total gross deferred tax assets	139,284	145,403
Less federal valuation allowance	2,911	2,284
Net deferred tax assets	136,373	143,119
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(202,520)	(215,322)
Decommissioning	(25,854)	(24,077)
Other	(13,481)	(11,891)
Total gross deferred tax liabilities	(241,855)	(251,290)
Net accumulated deferred income taxes	$ (105,482)	$ (108,171)

The deferred tax asset valuation allowance increased by approximately $0.6 million in 2004, and decreased $0.8 million and $6.8 million in 2003 and 2002, respectively. The 2004 valuation allowance increase of $0.6 million consists of a revaluation of investment tax credits as a result of the IRS settlement. The 2003 valuation allowance decrease of $0.8 million consists of (i) a $0.3 million

adjustment to capital in excess of stated value in accordance with Statement of Position ("SOP") 90-7, "Financial Reporting by Entities in Reorganization Under Bankruptcy Code" to recognize a tax benefit for valuation allowance that was not used as a result of investment tax credits that were utilized in 2003 and (ii) a $0.5 million writedown related to expired investment tax credits of $0.8 million less deferred tax benefits of $0.3 million. The 2002 valuation allowance decrease of $6.8 million consists of (i) a $4.5 million writedown related to expired investment tax credit of $6.9 million less deferred tax benefits of $2.4 million and (ii) a $2.3 million adjustment to capital in excess of stated value in accordance to SOP 90-7 to recognize a tax benefit for valuation allowance that was not used as a result of investment tax credits that were utilized in 2002.

Based on the average annual book income before taxes for the prior three years and future projected annual book income, excluding the effects of extraordinary and unusual or infrequent items, the Company believes that the net deferred tax assets will be fully realized at current levels of book and taxable income. The Company's valuation allowance of $2.9 million at December 31, 2004, if subsequently recognized as a tax benefit, would be credited directly to capital in excess of stated value in accordance with SOP 90-7.

The Company recognized income taxes as follows (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Income tax expense:			
Federal:			
Current	$ 10,542	$ 1,873	$ 9,668
Deferred	10,905	30,541	6,324
Total federal income tax	21,447	32,414	15,992
State:			
Current	(1,745)	1,297	4,508
Deferred	(9,499)	4,553	(3,996)
Total state income tax	(11,244)	5,850	512
Total income tax expense	10,203	38,264	16,504
Tax expense classified as extraordinary gain on re-application of SFAS No. 71	(1,005)	–	–
Tax expense classified as cumulative effect of accounting change	–	(25,031)	–
Total income tax expense before extraordinary item and cumulative effect of accounting change	$ 9,198	$ 13,233	$ 16,504

The current federal income tax expense for 2004, 2003 and 2002 results primarily from the accrual of alternative minimum tax ("AMT"). The significant increase in 2004 from 2003 primarily

relates to the IRS settlement. Deferred federal income tax includes an offsetting AMT benefit of $18.9 million, $2.1 million and $13.0 million for 2004, 2003 and 2002, respectively. The state income tax benefit for 2004 results primarily from the state effects of the re-application of SFAS No. 71 to the Company's New Mexico jurisdictional operations and the IRS settlement.

Federal income tax provisions differ from amounts computed by applying the statutory rate of 35% to book income before federal income tax as follows (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Federal income tax expense computed on income at statutory rate	$ 15,881	$ 34,377	$ 15,812
Difference due to:			
State taxes, net of federal benefit	(2,485)	3,802	333
State taxes, net of federal benefit on re-application of SFAS No. 71	(4,823)	–	–
Other tax regulatory assets and liabilities on re-application of SFAS No. 71	4,846	–	–
Reduction in estimated contingent tax liability	(3,520)	–	–
Other	304	85	359
Total income tax expense	10,203	38,264	16,504
Tax expense classified as extraordinary gain on re-application of SFAS No. 71	(1,005)	–	–
Tax expense classified as cumulative effect of accounting change	–	(25,031)	–
Total income tax expense before extraordinary item and cumulative effect of accounting change	$ 9,198	$ 13,233	$ 16,504
Effective income tax rate	22.5%	39.0%	36.5%
Effective income tax rate without IRS settlement	36.2%	39.0%	36.5%

The effective income tax rate without IRS settlement excludes the tax benefit associated with the reduction in estimated contingent tax liability of $3.5 million and state taxes net of federal benefit of $2.7 million. See Note I.

As of December 31, 2004, the Company had $0.5 million of federal tax NOL carryforwards, $1.4 million of capital loss carryforwards, $5.6 million of investment tax credit ("ITC") carryforwards including $0.2 million of wind energy tax credit, and $51.5 million of AMT credit carryforwards. If unused, the NOL carryforwards would expire at the end of 2011, the capital loss carryforwards would expire in 2007 through 2008, the ITC carryforwards would expire in 2005, the wind energy credit carryforwards would expire in 2016 through 2019, and the AMT credit carryforwards have an unlimited life.

I. Commitments, Contingencies and Uncertainties

Power Contracts

As of December 31, 2004, the Company had entered into the following significant agreements with various counterparties for forward firm purchases and sales of electricity:

Type of Contract	Quantity	Term
Sale off-peak	50 MW	2005
Purchase on-peak	103 MW	2005
Purchase	133 MW	2006 through 2025

The Company also has an agreement with a counterparty for power exchanges under which the Company will receive 30 MW of on-peak capacity and associated energy through 2005 at the Eddy County tie and concurrently deliver the same amount at Palo Verde and/or Four Corners. The agreement also gives the counterparty the option to deliver up to 133 MW of off-peak capacity and associated energy through 2005 at the Eddy County tie and concurrently receive the same amount at Palo Verde and/or Four Corners. The Company will receive a guaranteed margin on any energy exchanged under the off-peak agreement.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state, tribal and local authorities. Those authorities govern current facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these environmental regulatory requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil, and/or criminal penalties. If the United States regulates green house gas emissions, the Company's fossil fuel generation assets will be faced with the additional cost of monitoring, controlling and reporting these emissions. In addition, unauthorized releases of pollutants or contaminants into the environment can result in costly cleanup obligations that are subject to enforcement by the regulatory agencies. Environmental regulations can change rapidly and are often difficult to predict. While the Company strives to prepare for and implement changes necessary to comply with changing environmental regulations, substantial expenditures may be required for the Company to comply with such regulations in the future.

The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis and believes it has made adequate provision in its financial statements to meet such obligations. As a result of this analysis, the Company has a provision for environmental remediation obligations of approximately $1.3 million as of December 31, 2004, which is related to compliance with federal and state environmental standards. However, unforeseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company.

The Company incurred the following expenditures to comply with federal environmental statutes (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Clean Air Act	$ 762	$ 1,060	$ 739
Clean Water Act (1)	1,206	649	1,930

(1) Includes $0.6 million and $1.6 million in remediation costs for the years ended December 31, 2004 and 2002, respectively.

Along with many other companies, the Company received from the Texas Commission on Environmental Quality ("TCEQ") a request for information dated October 15, 2003 in connection with environmental conditions at a facility in San Angelo, Texas that has been owned and operated by the San Angelo Electric Service Company ("SESCO"). The Company's written response to TCEQ notes that SESCO performed repair services for certain Company electrical equipment between 1981 and 1991, prior to the Company's bankruptcy. Although the SESCO site has not been designated as a state or federal Superfund site and the Company has not been named as a "responsible party" or a "potentially responsible party" at that site, the Company received in October 2004 an invitation to participate in site cleanup activities from a group of private companies that are conducting certain cleanup activities at the SESCO site. At this time, the Company has not agreed to participate in the cleanup of the SESCO site and is unable to predict the outcome of this matter, although the Company has no reason at present to believe that it will incur material liabilities in connection with the SESCO site.

Except as described herein, the Company is not aware of any other active investigation of its compliance with environmental requirements by the Environmental Protection Agency, the TCEQ or the New Mexico Environment Department which is expected to result in any material liability. Furthermore, except as described herein, the Company is not aware of any unresolved, potentially material liability it would face pursuant to the Comprehensive Environmental Response, Comprehensive Liability Act of 1980, also known as the Superfund law.

Tax Matters

The Company received final approval from the IRS during the third quarter of 2004 to settle all issues relative to its 1996 through 1998 federal income tax returns. As part of the settlement, the Company was required to capitalize (for tax purposes) approximately twenty percent of the previously claimed lease rejection damage deductions. In addition, the IRS conceded the litigation settlement issue related to a terminated merger agreement. As a result of the IRS settlement, the Company reduced its estimated contingent tax liability by $3.5 million related to the resolution of certain tax contingency items and adjusted its state deferred tax liabilities (net of federal tax benefit) by $2.7 million. The IRS settlement reduced income tax expense by approximately $6.2 million during 2004 which increased net

income for 2004 by the same amount. The IRS is currently performing an examination of the 1999 through 2002 income tax returns. The Company has established, and periodically reviews and re-evaluates, an estimated contingent tax liability on its consolidated balance sheet to provide for the possibility of adverse outcomes in tax proceedings. Although the ultimate outcome of the ongoing examination cannot be predicted with certainty, and while the contingent tax liability may not in fact be sufficient, the Company believes that the amount of contingent tax liability recorded as of December 31, 2004 is a reasonable estimate of any additional tax that may be due.

MiraSol Warranty Obligations

MiraSol is an energy services subsidiary which offered a variety of services to reduce energy use and/or lower energy costs. MiraSol was not a power marketer. On July 19, 2002, all sales activities of MiraSol ceased. MiraSol remains a going concern in order to satisfy current contracts and warranty and service obligations on previously installed projects. Management of MiraSol continues to assess projects for potential warranty obligations. As part of the assessment, several discussions have been held with a large customer on a $5.6 million generator project. Two warranty issues associated with the project have been identified, and management has contracted with a third party to address the warranty claims. As of December 31, 2004, the Company has a reserve for those warranty claims in the amount of $1.3 million. Accruals, charges and balances for the reserve for warranty claims are as follows:

	Years Ended December 31,		
	2004	2003	2002
Balance at beginning of year	$ 1,500	$ 1,413	$ –
Accrual of warranty costs	–	466	2,000
Charges for work performed	(195)	(379)	(587)
Balance at end of year	$ 1,305	$ 1,500	$ 1,413

While no other probable warranty liabilities have been identified at this time, if it is determined at a future date that MiraSol has further obligations to this customer or any other customer, and contributions from MiraSol, its subcontractors or any other third party are insufficient to honor the warranty obligations, the Company intends to honor any such warranty obligations after making appropriate regulatory filings, if any.

Customer Information System

During 2003, the Company completed an assessment of the Customer Information System ("CIS") project and of alternatives to completion of the project. This assessment included analyzing the impact that potential delays in the implementation of deregulation and resulting changes in billing requirements, and the software's ability to perform to specification. Based on this assessment and on events related to the project which occurred, the Company abandoned the CIS project and recognized an asset impairment loss of approximately $17.6 million. The Company is now analyzing various options to meet its current and projected CIS needs.

Lease Agreements

The Company has operating leases for administrative offices and certain warehouse facilities. The administrative offices lease has a 10-year term ending May 31, 2007. The minimum lease payments are $1.0 million annually and are adjusted each year by 50% of the percentage change of the Consumer Price Index. The warehouse facilities lease expires in January 2006 and has two concurrent renewal options of six months each. The lease payments are $0.3 million annually. The lease agreements do not impose any restrictions relating to issuance of additional debt, payment of dividends or entering into other lease arrangements. The Company has no significant capital lease agreements.

The Company's total annual rental expense related to operating leases was $1.2 million for 2004 and $1.9 million for 2003 and 2002. As of December 31, 2004, the Company's minimum future rental payments for the next five years are as follows (in thousands):

2005	$ 1,282
2006	1,026
2007	400
2008	–
2009	–

Union Matters

In 2003, a majority of employees in the Company's meter reading and collections areas and facilities services area, comprised of 75 employees, voted in favor of representation by the International Brotherhood of Electrical Workers, Local 960 ("Local 960"). In 2004, a majority of employees in the customer service area, comprised of 63 employees, voted in favor of representation by Local 960. The Company has begun collective bargaining negotiations with Local 960 on behalf of these employees.

J. Litigation

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, the Company believes that, except as described below, none of these claims will have a material adverse effect on the financial position, results of operations and cash flows of the Company. The Company expenses legal costs, including expenses related to loss contingencies, as they are incurred.

On January 16, 2003, the Company was served with a complaint on behalf of a purported class of shareholders alleging violations of the federal securities laws (*Roth v. El Paso Electric Company, et al.*, No. EP-03-CA-0004). The complaint was filed in the El Paso Division of the United States District Court for the Western District of Texas. The suit seeks undisclosed compensatory damages for the class as well as costs and attorneys' fees. The lead plaintiff, Carpenters Pension Fund of Illinois, filed a consolidated amended complaint on July 2, 2003, alleging, among other things, that the Company and

certain of its current and former directors and officers violated securities laws by failing to disclose that some of the Company's revenues and income were derived from an allegedly unlawful relationship with Enron. The allegations arise out of the FERC investigation of the power markets in the western United States during 2000 and 2001, which the Company previously settled with the FERC Trial Staff and certain intervening parties. On August 15, 2003, the Company and the individual defendants filed a motion to dismiss the complaint for failure to state a claim upon which relief can be granted. On November 26, 2003, the Court denied the motion to dismiss as to the Company and three of the individual defendants and granted the motion to dismiss as to two individual defendants. On April 13, 2004, the Court granted a motion of the Company and the remaining individual defendants requesting permission to file an interlocutory appeal to the U. S. Court of Appeals for the Fifth Circuit regarding certain legal questions relating to the Court's denial of the motion to dismiss the complaint as to those defendants. On April 27, 2004, the Court entered an order staying the district court proceedings until the Fifth Circuit completed its review. On June 7, 2004, the U. S. Court of Appeals denied the appeal which automatically lifted the stay in the district court. This matter is presently set for trial on September 19, 2005, but such date may be extended. While the Company believes the lawsuit is without merit and intends to defend itself vigorously, the Company is unable to predict the outcome or the range of any possible loss.

On May 21, 2003, the Company was served with a complaint by the Port of Seattle seeking civil damages under the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, and state anti-trust laws, as well as for fraud (*Port of Seattle v. Avista Corporation, et al.*, No. CV03-117OP). The complaint was filed in the United States District Court for the Western District of Washington. The complaint alleges that the Company, indirectly through its dealings with Enron, conspired with the other named defendants to manipulate the California energy market, which had the effect of artificially inflating the price that the Port of Seattle paid for electricity. The Company, together with several other defendants, filed a motion to dismiss. On May 12, 2004, the Court granted the Company's motion, and the suit was dismissed. The Port of Seattle has filed an appeal of the Court's decision with the U. S. Court of Appeals for the Ninth Circuit. The parties have filed briefs and are awaiting a hearing and decision. While the Company believes that these matters are without merit, the Company is unable to predict the outcome or range of any possible loss.

On November 3, 2003, TNP filed a complaint against the Company with the FERC, asking the FERC to make a determination that TNP has certain "rollover rights" to network-type transmission service over the Company's transmission system as a result of a power sales agreement between it and the Company which expired at the end of 2002. TNP asserted that it has such rights under the rollover provisions of FERC Order No. 888. The Company responded to TNP's complaint by contesting TNP's assertion of rollover rights on several grounds. Due to existing transmission constraints, a FERC ruling granting TNP's complaint could have adversely impacted the Company's ability to import lower cost power from Palo Verde and Four Corners to serve its retail customers, which could have resulted in higher rates for the Company's retail electric customers. A hearing on this matter before an administrative law judge ("ALJ") was held on July 19 and 20, 2004, and, on September 20, 2004, the

ALJ issued a proposed decision, dismissing TNP's complaint and concluding that TNP has no rollover rights over the Company's transmission system. On March 2, 2005, the Commission issued an order affirming the dismissal of TNP's complaint.

On June 29, 2004, the Company filed suit against TNP in the Third Judicial District Court of New Mexico, claiming that TNP acted in bad faith by claiming such transmission rights and seeking to obtain use of more transmission rights than originally allocated to TNP under its original contract with the Company. The Company seeks both actual and exemplary damages from TNP as well as a declaration that TNP breached its agreements with the Company, acted in bad faith and violated New Mexico law prohibiting such actions. On November 1, 2004, the Company filed a motion for leave to amend the complaint to add PNM as a defendant in this action, alleging, among other things, that PNM tortiously interfered with the Company's contractual relationships with TNP. On November 22, 2004, the Company, TNP and PNM entered into a settlement agreement (contingent upon FERC approval) whereby (i) TNP would withdraw its complaint against the Company with the FERC and no longer seek certain rollover transmission rights from the Company; (ii) the Company would dismiss its claims against TNP and PNM in the New Mexico district court; and (iii) TNP would reimburse the Company for certain costs incurred in defending the FERC action. On March 2, 2005, the settlement was approved by the FERC.

On May 5, 2004, Wah Chang, a specialty metals manufacturer which operates a plant in Oregon, filed suit against the Company and other defendants in the United States District Court for the District of Oregon. (*Wah Chang v. Avista Corporation, et al.*, No. 04-619AS). The complaint makes substantially the same allegations as were made in *Port of Seattle* and seeks the same types of damages. In addition, on June 7, 2004, the City of Tacoma filed suit against the Company and other defendants in the United States District Court for the Western District of Washington (*City of Tacoma v. American Electric Power Service Corp., et al.*, C04-5325RBL). This complaint also makes substantially the same allegations as were made in *Port of Seattle* and seeks civil damages (including treble damages) from the Company and the other defendants for violations of certain antitrust provisions under the Sherman Act. Both of these matters were transferred to the same court that heard and dismissed the *Port of Seattle* lawsuit and on February 11, 2005, the Court granted the Company's motion to dismiss both cases. Wah Chang and the City of Tacoma have thirty days in which to appeal the Court's decision with the U.S. Court of Appeals for the Ninth Circuit. While the Company believes that these matters are without merit, the Company is unable to predict the outcome or range of any possible loss.

K. Employee Benefits

Retirement Plans

The Company's Retirement Income Plan (the "Retirement Plan") covers employees who have completed one year of service with the Company and work at least a minimum number of hours each year. The Retirement Plan is a qualified noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the Retirement Plan are used to pay benefit obligations under the

Retirement Plan. Contributions from the Company are at least the minimum funding amounts required by the IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, debt securities and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company's non-qualified retirement income plan for 2003 and 2002 is a non-funded defined benefit plan which covers certain former employees of the Company. During 2004, the Company adopted a new non-qualified retirement income plan to cover certain active employees of the Company. The benefit cost for the non-qualified retirement income plans are based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan.

The Company uses a measurement date of December 31 for its retirement plans. The Company accounts for the Retirement Plan and the non-qualified retirement income plans under SFAS No. 87, "Employers' Accounting for Pensions." In 2003, the Company adopted SFAS No. 132 (revised 2003), "Employers' Disclosure about Pensions and Other Postretirement Benefits," ("SFAS No. 132 revised") which expands the original disclosure requirements of SFAS No. 132.

The obligations and funded status of the plans are presented below (in thousands):

	December 31,			
	2004		2003	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Change in benefit obligation:				
Benefit obligation at end of prior year	$ 150,178	$ 19,816	$ 130,754	$ 19,185
Service cost	4,382	59	3,812	–
Interest cost	8,891	1,227	8,403	1,207
Amendments	–	1,162	–	–
Actuarial loss	6,457	796	11,513	1,074
Benefits paid	(4,627)	(1,656)	(4,304)	(1,650)
Benefit obligation at end of year	165,281	21,404	150,178	19,816
Change in plan assets:				
Fair value of plan assets at end of prior year	87,558	–	72,466	–
Actual return on plan assets	8,751	–	11,106	–
Employer contribution	14,000	1,656	8,290	1,650
Benefits paid	(4,627)	(1,656)	(4,304)	(1,650)
Fair value of plan assets at end of year	105,682	–	87,558	–
Funded status at end of year	(59,599)	(21,404)	(62,620)	(19,816)
Unrecognized net actuarial loss	54,915	3,731	52,613	3,029
Unrecognized prior service cost	176	1,068	196	–
Accrued benefit cost	$ (4,508)	$ (16,605)	$ (9,811)	$ (16,787)

Amounts recognized in the Company's consolidated balance sheets consist of the following (in thousands):

	December 31,			
	2004		2003	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Prepaid benefit cost	$ –	$ –	$ –	$ –
Accrued benefit cost	(4,508)	(16,605)	(9,811)	(16,787)
Additional minimum liability	(24,128)	(3,814)	(23,373)	(3,029)
Intangible assets	176	147	196	–
Accumulated other comprehensive income	23,952	3,667	23,177	3,029
Net amount recognized	$ (4,508)	$ (16,605)	$ (9,811)	$ (16,787)

The accumulated benefit obligation for all retirement plans was $154.7 million and $140.6 million at December 31, 2004 and 2003, respectively.

The accumulated benefit obligation in excess of plan assets is as follows (in thousands):

	December 31,			
	2004		2003	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Projected benefit obligation	$ (165,281)	$ (21,404)	$ (150,178)	$ (19,816)
Accumulated benefit obligation	(134,317)	(20,419)	(120,742)	(19,816)
Fair value of plan assets	105,682	–	87,558	–

The following are the weighted-average actuarial assumptions used to determine the benefit obligations:

	December 31,			
	2004		2003	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Discount rate	5.75%	5.75%	6.00%	6.00%
Rate of compensation increase	5.00%	N/A	5.00%	N/A

The components of net periodic benefit cost are presented below (in thousands):

	Years Ended December 31,					
	2004		2003		2002	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Service cost	$ 4,382	$ 59	$ 3,812	$ –	$ 3,359	$ –
Interest cost	8,891	1,227	8,403	1,207	7,867	1,257
Expected return on plan assets	(7,926)	–	(7,536)	–	(7,761)	–
Amortization of:						
Net loss	3,329	94	1,720	16	–	–
Prior service cost	21	94	21	–	21	–
Net periodic benefit cost	$ 8,697	$ 1,474	$ 6,420	$ 1,223	$ 3,486	$ 1,257

The increase in minimum liability included in other comprehensive income is as follows (in thousands):

	Years Ended December 31,					
	2004		2003		2002	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Increase in minimum liability included in other comprehensive income	$ 775	$ 638	$ 3,175	$ 1,059	$ 20,002	$ 1,146

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost at January 1, 2004:

	2004		2003		2002	
	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans	Retirement Income Plan	Non-Qualified Retirement Income Plans
Discount rate	6.00%	6.00%	6.50%	6.50%	7.00%	7.00%
Expected long-term return on plan assets	8.50%	N/A	8.50%	N/A	8.50%	N/A
Rate of compensation increase	5.00%	N/A	5.00%	N/A	5.00%	N/A

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on prevailing market interest rates inherent in high-

quality (AA and better) corporate bonds that would provide the future cash flow needed to pay the benefits included in the benefit obligation as they become due, as well as on publicly available bond indices. The Company changed its discount rate to determine the benefit obligations from 6.00% to 5.75% at December 31, 2004. For determining 2005 benefit costs, the 5.75% discount rate is not expected to change. A 1.0% decrease in the discount rate would increase the 2004 retirement plans' projected benefit obligation by 16%. A 1.0% increase in the discount rate would decrease the 2004 retirement plans' projected benefit obligation by 13%.

The Company's overall expected long-term rate of return on assets is 8.50%, which is both a pre-tax and after-tax rate as pension funds are generally not subject to income tax. The expected long-term rate of return is based on the sum of the expected returns on individual asset categories with a target asset allocation of 65% equity and 35% debt securities. The expected returns for equity securities are based on historical risk premiums above the current fixed income rate, while the expected returns for the debt securities are based on the portfolio's yield to maturity.

Given recent market conditions, the Company has emphasized capital preservation and therefore, the asset allocations at December 31, 2004 and 2003 do not reflect the targeted long-term asset allocation which remains unchanged. The Company's Retirement Plan weighted-average asset allocations by asset category are as follows:

	December 31,	
	2004	2003
Asset Category:		
Equity securities	45%	41%
Debt securities	32	35
Cash equivalents	23	24
Total	100%	100%

The Company's investment goals for the Retirement Plan are to maximize returns subject to specific risk management policies. Its risk management policies permit investments in equity and debt securities, mutual funds and cash/cash equivalents and prohibit direct investments in fixed income derivatives, foreign debt securities, real estate or commingled funds, private placements and tax-exempt debt of state and local governments. The Company addresses diversification by the use of mutual fund investments whose underlying investments are in domestic and international equity securities and domestic fixed income securities. The liquidity of these funds is enhanced through the purchase of highly marketable securities.

The contributions for the Retirement Plan, as actuarially calculated, are based on the minimum funding amounts required by the IRS. The Company expects to contribute $18.5 million to its retirement plans in 2005, although the Company has no 2005 minimum funding requirements for the Retirement Plan.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Income Plans
2005	$ 5,154	$ 1,769
2006	5,375	1,582
2007	5,614	1,553
2008	5,998	1,521
2009	6,671	1,488
2010-2014	44,720	7,634

Other Postretirement Benefits

The Company provides certain health care benefits for retired employees and their eligible dependents and life insurance benefits for retired employees only. Substantially all of the Company's employees may become eligible for those benefits if they retire while working for the Company. Those benefits are accounted for under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Contributions from the Company are based on the funding amounts required by the Texas Commission in the Texas Rate Stipulation. The assets of the plan are invested in equity securities, debt securities, and cash equivalents and are managed by professional investment managers appointed by the Company. The Company uses a measurement date of December 31 for its other postretirement benefits plan.

In December 2003, the Company elected to defer recognition of the potential effect of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "Act") until authoritative guidance on the accounting for the federal subsidy is issued. In May 2004, the FASB issued FASB Staff Position No. 106-2 "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," ("FSP 106-2") which provided guidance on the accounting for the effects of the Act for employers that sponsor a single-employer defined benefit postretirement healthcare plan for which the employer has concluded that prescription drug benefits available under the plan are actuarially equivalent to the Medicare Part D benefit and the expected subsidy will offset or reduce the employer's share of the cost of the benefit. The Company determined that the prescription drug benefit of its plan were actuarially equivalent to the Medicare Part D benefit. FSP 106-2 requires measurement of the accumulated postretirement benefit obligation and the net periodic postretirement benefit cost to reflect the effects of the subsidy. The effect of the Medicare Part D subsidy on the accumulated postretirement benefit obligation and net periodic benefit cost, is shown below (in thousands):

	Included	Excluded
Accumulated postretirement benefit obligation as of January 1, 2004	$ 98,621	$ 113,569
Fiscal 2004 expense:		
Service cost	$ 3,796	$ 4,346
Interest cost	5,839	6,736
Expected return on plan assets	(1,258)	(1,258)
Amortization of unrecognized amounts:		
Transition obligation (asset)	–	–
Prior service cost	(251)	(251)
Net actuarial gain	(387)	–
Net periodic postretirement benefit cost	$ 7,739	$ 9,573

The obligations and funded status of the plan are presented below (in thousands):

	December 31,	
	2004	2003
Change in benefit obligation:		
Benefit obligation at end of prior year	$ 118,182	$ 96,561
Service cost	3,796	3,915
Interest cost	5,839	6,468
Amendments	(2,210)	–
Actuarial (gain) loss	(8,490)	13,525
Benefits paid	(2,800)	(2,597)
Retiree contributions	320	310
Benefit obligation at end of year	114,637	118,182
Change in plan assets:		
Fair value of plan assets at end of prior year	20,906	16,716
Actual return on plan assets	1,359	3,055
Employer contribution	3,422	3,422
Benefits paid	(2,800)	(2,597)
Retiree contributions	320	310
Fair value of plan assets at end of year	23,207	20,906
Funded status	(91,430)	(97,276)
Unrecognized net actuarial (gain) loss	(5,438)	2,766
Unrecognized prior service benefit	(1,959)	–
Accrued postretirement cost	$ (98,827)	$ (94,510)

Amounts recognized in the Company's consolidated balance sheets consist of accrued postretirement costs of $98.8 million and $94.5 million for 2004 and 2003, respectively. The discount rates used to determine the accrued postretirement cost were 5.75% and 6.00% at December 31, 2004

and 2003, respectively. The rate of compensation increase was 5% for both December 31, 2004 and 2003.

The components of net periodic benefit cost are presented below (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Service cost	$ 3,796	$ 3,915	$ 3,118
Interest cost	5,839	6,468	5,692
Expected return on plan assets	(1,258)	(1,020)	(999)
Amortization of:			
Prior service cost	(251)	–	–
Net gain	(387)	–	(794)
Net periodic benefit cost	$ 7,739	$ 9,363	$ 7,017

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost:

	2004	2003	2002
Discount rate at beginning of year	6.00%	6.50%	7.00%
Expected long-term return on plan assets	5.90%	5.90%	5.90%
Rate of compensation increase	5.00%	5.00%	5.00%
Trend rates:			
Initial	9.60%	9.60%	10.80%
Ultimate	6.00%	6.00%	6.00%
Years ultimate reached	4	4	5

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on prevailing market interest rates inherent in high-quality (AA and better) corporate bonds that would provide the future cash flow needed to pay the benefits included in the benefit obligation as they become due, as well as on publicly available bond indices. At December 31, 2004, the Company changed its discount rate from 6.00% to 5.75% for the other postretirement benefits plan. For determining 2005 benefit cost, the 5.75% discount rate is not expected to change. A 1.0% decrease in the discount rate would increase the 2004 accumulated postretirement benefit obligation by 19%. A 1.0% increase in the discount rate would decrease the 2004 accumulated postretirement benefit obligation by 16%.

For measurement purposes, a 9.6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005; the rate was assumed to decrease gradually to 6% for 2008 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. The effect of a 1% change in these assumed health care cost

trend rates would increase or decrease the benefit obligation by $18.1 million or $14.5 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of the net periodic benefit cost by $1.8 million or $1.4 million, respectively.

The Company's overall expected long-term rate of return on assets, on an after-tax basis, is 5.90%. This return is based on the sum of the expected returns on individual asset categories with a target asset allocation of 60% equity and 40% debt securities. The expected returns for equity securities are based on historical risk premiums above the current fixed income rate, while the expected returns for the debt securities are based on the portfolio's yield to maturity.

Given recent market conditions, the Company has emphasized capital preservation and therefore, the asset allocations at December 31, 2004 and 2003 do not reflect the targeted long-term asset allocation which remains unchanged. The Company's other postretirement benefits plan weighted average asset allocations by asset category are as follows:

	December 31,	
	2004	2003
Asset Category:		
Equity securities	54%	54%
Debt securities	30	33
Cash equivalents	16	13
Total	100%	100%

The Company's investment goals for the postretirement benefits plan are to maximize returns subject to specific risk management policies. Its risk management policies permit investments in equity and debt securities, mutual funds and cash/cash equivalents and prohibit direct investments in fixed income derivatives, foreign debt securities, real estate or commingled funds and private placements. The Company's investment policies and strategies for the postretirement benefits plan are based on target allocations for individual asset categories. The Company addresses diversification by the use of mutual fund investments whose underlying investments are in domestic and international equity securities and domestic fixed income securities. The liquidity of these funds is enhanced through the purchase of highly marketable securities.

The Company expects to contribute $3.4 million to its other postretirement benefits plan in 2005.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

2005	$ 3,073
2006	3,209
2007	3,617
2008	4,086
2009	4,527
2010-2014	32,219

401(k) Defined Contribution Plans

The Company sponsors 401(k) defined contribution plans covering substantially all employees. Historically, the Company has provided a 50 percent matching contribution up to 6 percent of the employee's base salary subject to certain other limits. Total matching contributions made to the savings plans for the years 2004, 2003 and 2002 were $1.3 million, $1.3 million and $1.4 million, respectively.

Annual Short-Term Bonus Plan

The Annual Short-Term Bonus Plan (the "Bonus Plan") provided for the payment of cash awards to eligible Company employees, including each of its named executive officers. Payment of awards was based on the achievement of performance measures reviewed and approved by the Company's Board of Directors Compensation Committee. Generally, these performance measures were based on meeting certain financial, operational and individual performance criteria. For 2004, the financial performance goals were based on earnings per share and the operational performance goals were based on safety and customer satisfaction. If a certain level of earnings per share was not attained, no bonuses would have been paid under the Bonus Plan. The Company was able to attain the required levels of improvements in the earnings per share and the customer satisfaction goals which resulted in a 2004 bonus of $3.5 million. The Company was also able to attain the required levels of improvement in the safety performance measures for medium and high risk employees in 2004, 2003 and 2002, which resulted in safety bonuses of $0.9 million, $0.7 million and $1.0 million, respectively. The Company has renewed the Bonus Plan in 2005 with similar goals.

L. Franchises and Significant Customers

City of El Paso Franchise

The Company's largest franchise agreement is with the City. The franchise agreement includes a 2% annual franchise fee (approximately $7.9 million per year currently) and allows the Company to utilize public rights-of-way necessary to serve its retail customers within the City. The franchise with the City extends through August 1, 2005.

The Company's franchise agreement with the City included an option to acquire all of the non-cash assets of the Company at the end of the term of the franchise on August 1, 2005. To exercise the option, the City was required to deliver written notice to the Company one year prior to the expiration of the franchise term. The option expired unexercised on August 1, 2004.

Las Cruces Franchise

In February 2000, the Company and Las Cruces entered into a seven-year franchise agreement with a 2% annual franchise fee (approximately $1.2 million per year currently) for the provision of electric distribution service. Las Cruces is prohibited during this seven-year period from taking any action to condemn or otherwise attempt to acquire the Company's distribution system, or attempt to operate or build its own electric distribution system. Las Cruces will have a 90-day non-assignable option at the end of the Company's seven-year franchise agreement to purchase the portion of the Company's distribution system that serves Las Cruces at a purchase price of 130% of the Company's book value at that time. If Las Cruces exercises this option, it is prohibited from reselling the distribution assets for two years. If Las Cruces fails to exercise this option, the franchise and standstill agreements will be extended for an additional two years.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represent approximately 3% of annual operating revenues. The Company currently has contracts with all three military bases that it serves. The Company signed a contract with Ft. Bliss in December 1998 under which Ft. Bliss will take retail electric service from the Company through December 2008. The Company has a contract to provide retail electric service and limited wheeling services to Holloman for a ten-year term which expires in December 2005. In May 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands.

M. Financial Instruments and Investments

SFAS No. 107, "Disclosure about Fair Value of Financial Instruments," requires the Company to disclose estimated fair values for its financial instruments. The Company has determined that cash and temporary investments, accounts receivable, decommissioning trust funds, long-term debt and financing obligations, accounts payable and customer deposits meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable and customer deposits approximate fair value because of the short maturity of these items. Decommissioning trust funds are carried at market value.

The fair values of the Company's long-term debt and financing obligations, including the current portion thereof, are based on estimated market prices for similar issues and are presented below (in thousands):

	December 31,			
	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
First Mortgage Bonds	$ 359,362	$ 386,947	$ 395,366	$ 447,662
Pollution Control Bonds	193,135	197,871	193,135	201,700
Nuclear Fuel Financing (1)	41,196	41,196	42,176	42,176
Total	$ 593,693	$ 626,014	$ 630,677	$ 691,538

(1) The interest rate on the Company's financing for nuclear fuel purchases is reset every quarter to reflect current market rates. Consequently, the carrying value approximates fair value.

As of January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," including any effective implementation guidance discussed by the FASB Derivatives Implementation Group. This standard requires the recognition of derivatives as either assets or liabilities in the balance sheet with measurement of those instruments at fair value. Any changes in the fair value of these instruments are recorded in earnings or other comprehensive income.

The Company uses commodity contracts to manage its exposure to price and availability risks for fuel purchases and power sales and purchases and these contracts generally have the characteristics of derivatives. The Company does not trade or use these instruments with the objective of earning financial gains on the commodity price fluctuations. The Company has determined that all such contracts, except for certain natural gas commodity contracts with optionality features, that had the characteristics of derivatives met the "normal purchases and normal sales" exception provided in SFAS No. 133, and, as such, were not required to be accounted for as derivatives pursuant to SFAS No. 133 and other guidance.

The Company determined that certain of its natural gas commodity contracts with optionality features are not eligible for the normal purchases exception and, therefore, are required to be accounted for as derivative instruments pursuant to SFAS No. 133. However, as of December 31, 2004, the variable, market-based pricing provisions of existing gas contracts are such that these derivative instruments have no significant fair value.

The fair value of the Company's marketable securities at December 31, 2004 was $89.4 million. Gross unrealized losses on marketable securities and the fair value of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2004, were as follows:

	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities:						
U.S. Treasury Obligations and Direct Obligations of U.S. Government Agencies	$ 5,314	$ (75)	$ 298	$ (8)	$ 5,612	$ (83)
Federal Agency Mortgage Backed Securities	303	(3)	641	(13)	944	(16)
Municipal Obligations	596	(6)	1,153	(45)	1,749	(51)
Corporate Obligations	1,533	(19)	422	(7)	1,955	(26)
Total debt securities	7,746	(103)	2,514	(73)	10,260	(176)
Common stock	3,663	(317)	1,186	(390)	4,849	(707)
Total temporarily impaired securities	$ 11,409	$ (420)	$ 3,700	$ (463)	$ 15,109	$ (883)

The total impaired securities are comprised of approximately fifty investments that are in an unrealized loss position. The Company monitors the length of time the investment trades below its cost basis along with the amount and percentage of the unrealized loss in determining if a decline in fair value of marketable securities below original cost is considered to be other than temporary. In addition, the Company will research the future prospects of individual securities as necessary. As a result of these factors, as well as the Company's intent and ability to hold these investments until their market price recovers, these investments are not considered other-than-temporarily impaired. During the years ended December 31, 2004, 2003 and 2002, the Company recognized other than temporary impairment losses of marketable securities of $0.3 million, $0.6 million and $2.7 million, respectively.

N. Supplemental Statements of Cash Flows Disclosures

	Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Cash paid for:			
Interest on long-term debt and financing obligations	$ 49,392	$ 51,596	$ 55,785
Income taxes	9,385	17,660	15,133
Other interest	5	12	16
Non-cash investing and financing activities:			
Grants of restricted shares of common stock	812	724	1,586
Remeasurements of options	–	–	240
Change in federal and state deferred tax valuation allowance credited to capital in excess of stated value (1)	3,380	295	2,308
Plant in service acquired through incurring obligation subject to a service agreement	–	8,139	–

(1) See Note H.

O. Selected Quarterly Financial Data (Unaudited)

	2004 Quarters				2003 Quarters			
	4th	3rd	2nd	1st	4th	3rd	2nd	1st
	(In thousands except for share data)							
Operating revenues (1)	$165,629	$204,941	$182,206	$155,852	$156,953	$197,425	$162,498	$147,486
Operating income	7,853	40,612	26,337	18,820	16,666	28,480	19,175	15,414
Income (loss) before extraordinary item and cumulative effect of accounting change	(1,182)	23,938	7,699	2,914	2,185	11,172	4,922	2,043
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	1,802	–	–	–	–	–	–
Cumulative effect of accounting change, net of tax	–	–	–	–	–	–	–	39,635
Net income (loss)	(1,182)	25,740	7,699	2,914	2,185	11,172	4,922	41,678
Basic earnings per share:								
Income (loss) before extraordinary item and cumulative effect of accounting change	(0.02)	0.50	0.16	0.06	0.05	0.23	0.10	0.04
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	0.04	–	–	–	–	–	–
Cumulative effect of accounting change, net of tax	–	–	–	–	–	–	–	0.81
Net income (loss)	(0.02)	0.54	0.16	0.06	0.05	0.23	0.10	0.85
Diluted earnings per share:								
Income (loss) before extraordinary item and cumulative effect of accounting change	(0.02)	0.50	0.16	0.06	0.05	0.23	0.10	0.04
Extraordinary gain on re-application of SFAS No. 71, net of tax	–	0.04	–	–	–	–	–	–
Cumulative effect of accounting change, net of tax	–	–	–	–	–	–	–	0.80
Net income (loss)	(0.02)	0.54	0.16	0.06	0.05	0.23	0.10	0.84

(1) Operating revenues are seasonal in nature, with the peak sales periods generally occurring during the summer months. Comparisons among quarters of a year may not represent overall trends and changes in operations.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. During the period covered by this report, the Company's chief executive officer and chief financial officer, after evaluating the effectiveness of the Company's "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e) and 15d-15(e)) as of December 31, 2004, (the "Evaluation Date"), concluded that as of the Evaluation Date, the Company's disclosure controls and procedures (as required by paragraph (b) of the Securities Exchange Act of 1934 Rules 13a-15 or 15d-15) were adequate and designed to ensure that material information relating to the Company and the Company's consolidated subsidiary would be made known to them by others within those entities.

Management's Annual Report on Internal Control Over Financial Reporting. Included herein under the caption "Management Report on Internal Control Over Financial Reporting" on page 44 of this report.

Changes in internal control over financial reporting. There were no changes in the Company's internal control over financial reporting in connection with the evaluation required by paragraph (d) of the Securities Exchange Act of 1934 Rules 13a-15 or 15d-15, that occurred during the quarter ended December 31, 2004, that materially affected, or that were reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

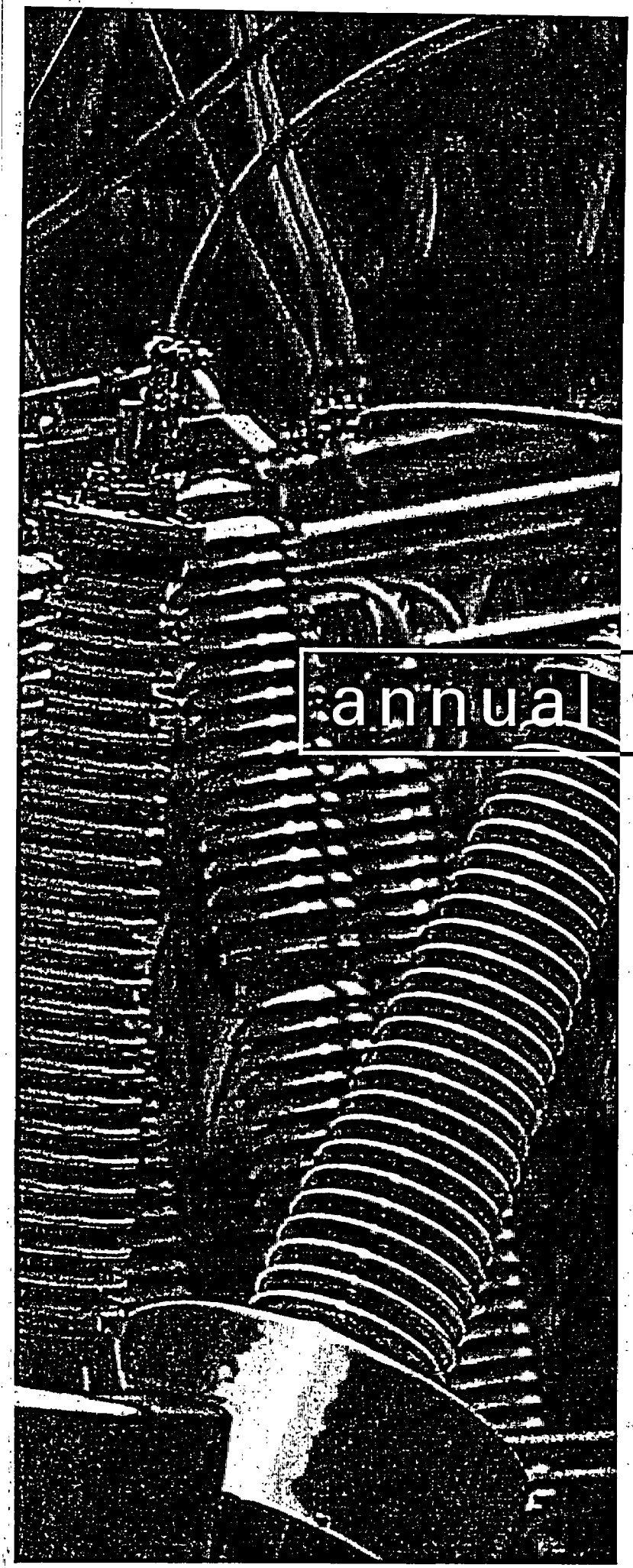
None.

PART III and PART IV

The information set forth in Part III and Part IV has been omitted from this Annual Report to Shareholders.

The Electric Company™

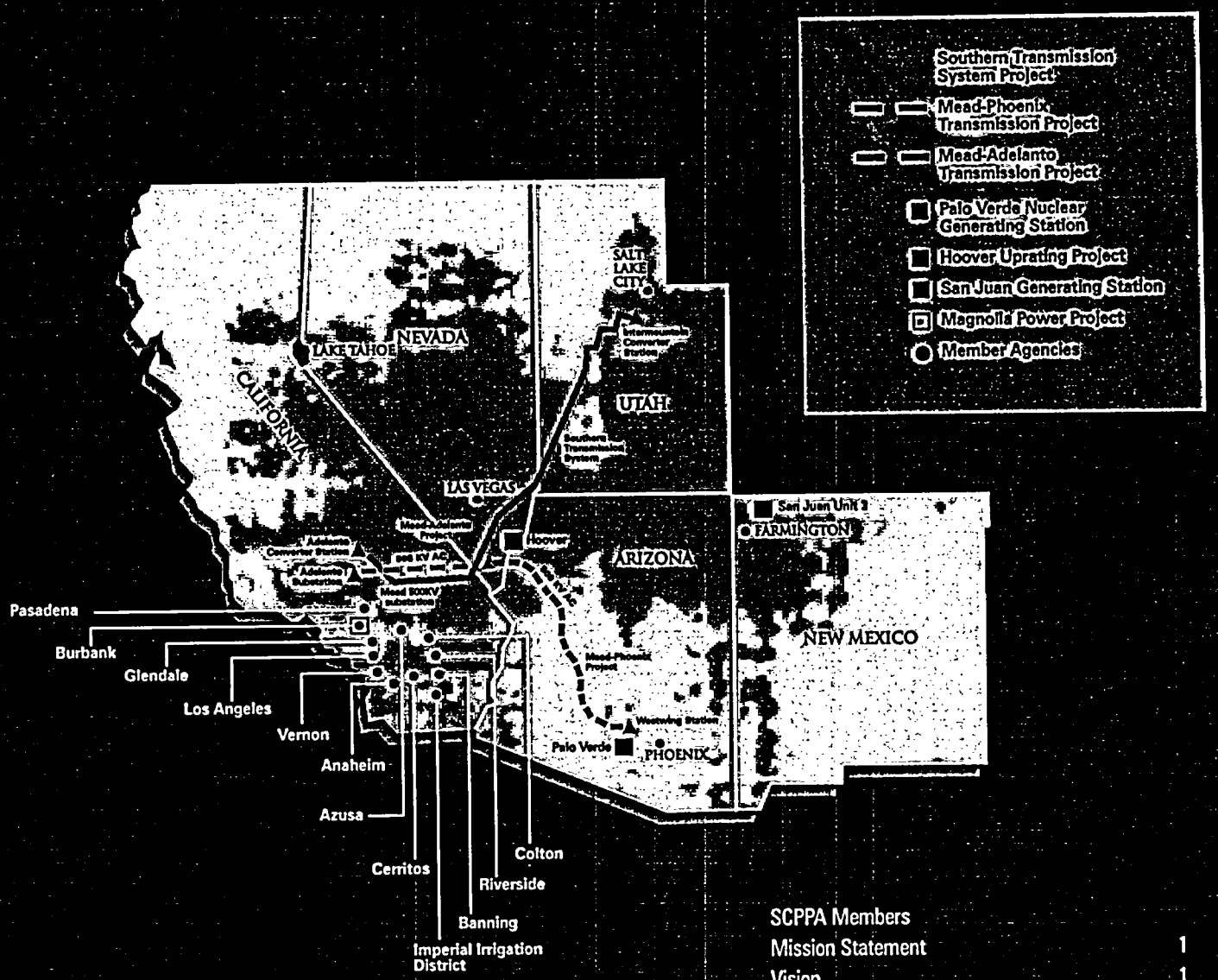
El Paso Electric



annual report

SCPPA

2003-2004



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WHAT IS SCPPA?

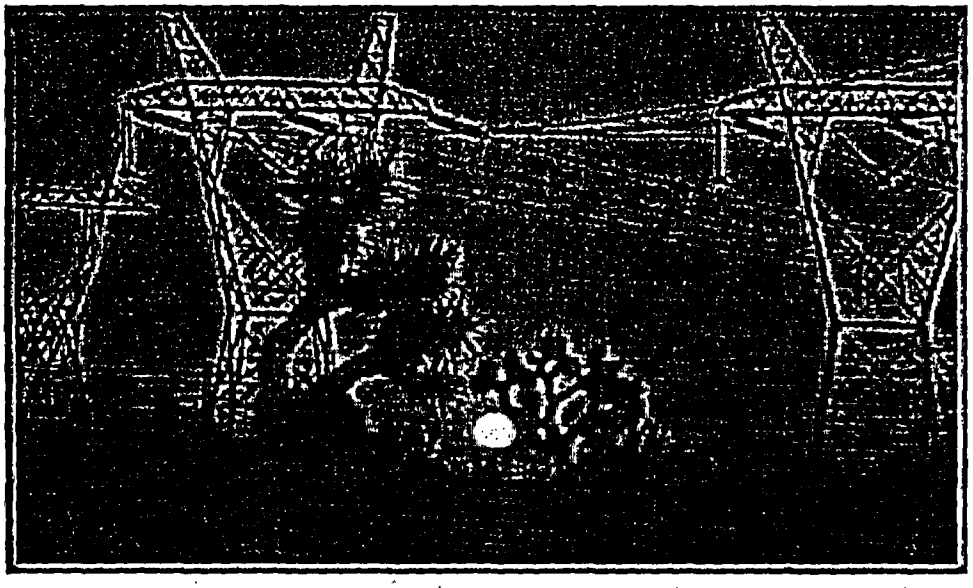
The Southern California Public Power Authority (SCPPA), with headquarters in Pasadena, California, is a joint powers authority consisting of eleven municipal utilities and one irrigation district. SCPPA members currently deliver electricity to over 2 million customers over an area of 7,000 square miles, and with a total population exceeding 5 million.

The members are the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, and the Imperial Irrigation District.

Formed in 1980 to finance the acquisition of generation and transmission resources for its members, SCPPA currently has three generation projects and three transmission projects in operation, generating and bringing power from Arizona, New Mexico, Utah, and Nevada. A fourth generation project, wholly owned by the Authority, is a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts currently in the construction phase and commercial operation is expected to begin in mid-2005.

The projects have been financed through the issuance of tax-exempt bonds, backed by the combined credit of SCPPA members participating in each project. As of June 30, 2004, SCPPA has issued $9.8 billion in bonds, notes, and refunding bonds, of which $2.5 billion was outstanding.

SCPPA's role has evolved over the years to include advocacy at the state and national levels, and various cooperative efforts to reduce member costs and improve efficiency.



MISSION

SCPPA provides financing and oversight for large joint projects in the electric utility industry and through coordinated efforts, it will facilitate, implement, and communicate information relative to issues and projects of mutual interest to its members as determined by the Board of Directors

VISION

SCPPA will provide cost-effective joint action services that supplement member programs and activities, and that secure long-term physical supplies at predictable pricing levels for usage in power generation to assure continued member success.

SCPPA OFFICERS

Bill D. Carnahan, Executive Director

Phyllis E. Currie, Vice President

Ronald E. Davis, President

Ronald O. Vazquez, Secretary

PRESIDENT'S LETTER

At the turn of the century, California was in the midst of the great "deregulation experiment". The viability of public power systems and joint action agencies became uncertain. Southern California Public Power Authority (SCPPA) responded to the numerous challenges by working together, and by taking action to implement a clear strategic plan. As a result, SCPPA and its members have become known as part of the "solution" to California's electricity industry problem, rather than part of the problem.

The story of SCPPA's success continues. The Authority's Members have worked together since 1980. On a combined basis, they currently deliver electricity and provide services to 2 million customers over an area of approximately 7,000 square miles. SCPPA is a participant in three major transmission projects and has three generation projects in operation, generating and bringing power to Southern California from Arizona, Nevada, New Mexico, and Utah.

SCPPA Members believe, and are continuing to demonstrate, that together more can be accomplished, and through joint action every participant can benefit. The latest example is the SCPPA-owned Magnolia Power Project (MPP). The MPP is a nominal, 250 megawatt (peak 310 megawatt), natural gas-fired combined cycle generation facility scheduled to go into commercial operation in May 2005. The project will serve the communities of Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena. The project is located in an urban setting, near downtown Burbank, and the Project Manager, Burbank Water and Power, has been extremely successful in gaining local support for the project from the City Council and its citizens. The project utilizes existing infrastructure, and is designed to operate solely on reclaimed waste water. When completed, MPP will be one of the most efficient and environmentally sensitive projects of its kind.

Through collaborative efforts of its members, SCPPA has developed a comprehensive and dynamic strategic plan that is a common vision for its members and a platform for action. SCPPA has dramatically increased its involvement in legislative and regulatory affairs at both state and federal levels to protect represented customers, and its executive team has assisted SCPPA in becoming highly successful by assuring resource adequacy, excellent reliability, and environmental stewardship. Much of this success can be attributed to SCPPA's Executive Director, Bill Carnahan. Under Bill's direction, the Authority's involvement and services to its members have grown dramatically during his tenure. SCPPA has provided effective forums of collaboration by the establishment of new committees that include Customer Service, Transmission and Distribution, Engineering and Operations, Public Benefits (conservation, research and energy demonstration programs), and Resource Planning and Renewables. These committees are assisting members to produce benchmarking and best practices; training; joint contracting for services and fuel acquisition for power generation; as well as, acquisition of renewable supplies such as wind, land-fill gas, and geothermal.

As President of SCPPA, I am proud to be part of the many accomplishments and the exciting opportunities for the Southern California public power utilities. With one of the strongest financial ratings in the utility industry, SCPPA continues in its traditional role of providing financing for our Members' generation and transmission projects by finding ways to reduce capital costs through debt refinancing. Working together, SCPPA members are providing and delivering reliable service with competitive and stable rates.

SCPPA is meeting the energy needs of our Members' customers and the communities they serve. Through the continued collaborative efforts of its members, SCPPA is well positioned to respond in meeting the new challenges in our industry.

Ronald E. Davis
President

THROUGH COLLABORATIVE EFFORTS OF ITS MEMBERS, SCPPA HAS DEVELOPED A COMPREHENSIVE AND DYNAMIC STRATEGIC PLAN THAT IS A COMMON VISION FOR ITS MEMBERS AND A PLATFORM FOR ACTION.

EXECUTIVE DIRECTOR'S LETTER

"Investing in the future", describes this year. Traditionally, SCPPA's investments have been in the areas of hydroelectric, nuclear, coal, and natural gas-fired generation as well as high voltage transmission to deliver the energy to California . To meet the challenges and increasing demand for energy, new investments in local base load and peaking natural gas-fired units will help satisfy these needs and increase overall system reliability. Planned expansion and re-powering projects through the year 2010 will add approximately 2,000 Megawatts of new gas-fired generation, and will be built to either replace current third-party power contracts or to retire older less efficient local generating units. Investments are also being made to provide customers with more renewable generation and energy efficiency. In the role as SCPPA's Executive Director, I am very proud to be a part of this expansion and continued success.

As a Joint Action Agency, SCPPA continues in its traditional role of providing financing for our Members' generation and transmission projects, managing various projects, and finding ways to reduce capital costs through debt refinancing. To take advantage of market conditions and low interest rates and maintain and reinforce our financial stability, we restructured debt, which resulted in over $18 million in gross debt service savings for our Members during the fiscal year.

The twelve Members of SCPPA are each independent, locally owned, and highly successful utilities. They provide reliable energy at competitive and stable rates and are sensitive to the communities and the environment in which they serve. Over the last few years, SCPPA has been expanding its role in order to meet the challenges facing the electric industry. The most dramatic example of success is the Magnolia Power Project (MPP), the first wholly-owned and operated SCPPA project. MPP, a combined cycled natural gas-fired plant, is located in Burbank, California. The Project is currently under construction and scheduled for operation in May 2005. When completed, MPP will generate 242 megawatts to meet base-load capacity and have a peaking capacity of more that 300 megawatts. Magnolia will utilize the latest technology requiring less fuel, is more efficient, and produces significantly less pollution than the older power plants it replaces. Most importantly, Magnolia will meet the strictest environmental standards and regulations in the nation.

Natural gas fired power generation has historically fulfilled peaking or intermediate demands, however, for economic, environmental and reliability reasons, SCPPA members have recently invested in a significant amount of base-load natural gas generation. While the new units will use less fuel on a per-unit basis, they will require natural gas at stable prices to produce reliable low-cost electricity. The SCPPA Board approved the Natural Gas Acquisition Project as a Study Project and entered into project development agreements with certain of its members and three non-SCPPA public utilities (the City of Redding, the Turlock Irrigation District, and the Southern Nevada Water Authority) to study the feasibility of purchasing non-operating working interests in natural gas producing properties. SCPPA's largest Member, the Los Angeles Department of Water and Power, was appointed and serves as the Project Manager, responsible for leading the project pursuant to the Natural Gas Project Development Agreement. The acquisition program will include several different properties acquired over a period of time. The overall form of financing for the project will include additional options for the SCPPA members to "bring their own money" or finance through SCPPA. An investment-banking firm was selected to lead the project's financing activities for SCPPA and a natural gas property advisor and engineering firms were hired to advise SCPPA regarding the desirability of potential gas property acquisitions.

In addition to the traditional type of investments, renewable energy will also continue to play an important role for the future. Investments by SCPPA members in renewable programs, have totaled nearly $70 million over the past five years. New renewable projects will further diversify generation portfolios, and also benefit the environment by reducing air emissions when compared to conventional generation.

Today, providing financing for new projects, seeking ways to reduce financing costs for existing projects, and coordinating all activities that provide collective benefits to the Members remain SCPPA's primary goals. SCPPA is also securing the future for its Members through both traditional and non-traditional investments. Through SCPPA, the Members have realized the value of collective leadership and the key to their success has been the collaborative efforts which they are applying in new and exciting directions in responding to the challenges and opportunities in our industry.

Working together in partnership with its Members, SCPPA is investing in the future.

THROUGH SCPPA, THE MEMBERS HAVE REALIZED THE VALUE OF COLLECTIVE LEADERSHIP AND THE KEY TO THEIR SUCCESS HAS BEEN THE COLLABORATIVE EFFORTS WHICH THEY ARE APPLYING IN NEW AND EXCITING DIRECTIONS IN RESPONDING TO THE CHALLENGES AND OPPORTUNITIES IN OUR INDUSTRY.

Bill D. Carnahan
Executive Director

INVESTING IN THE FUTURE

The Southern California Public Power Authority (SCPPA) was created in 1980 by the public power systems in Southern California to provide financing for their participation in electric generating facilities and high voltage transmission lines. The SCPPA member systems include the original eleven members, the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon, the Imperial Irrigation District, and the newest member, the city of Cerritos. Together, these twelve members serve over 2 million residential and business customers in Southern California representing a population of approximately 5.0 million people. **Most of the SCPPA member systems have been providing electricity and water to the public for over 100 years.**

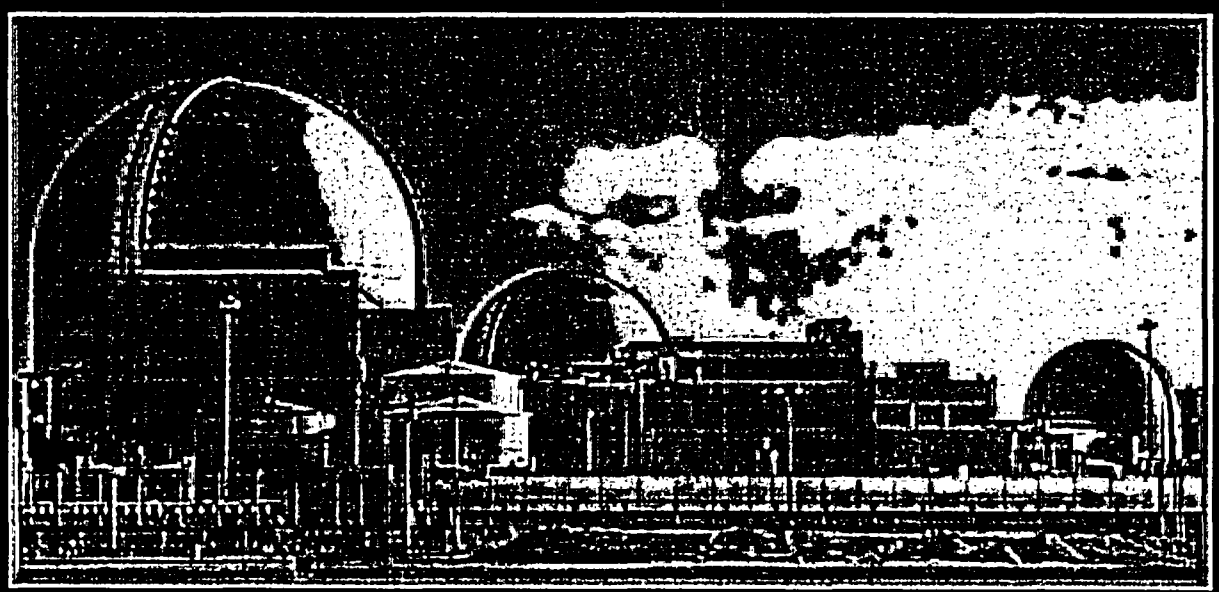
Throughout the California energy crisis, the continued success story has been the public power systems working through the diversity of their resources and investment in renewable energy sources. Over the years, the Southern California public power systems have invested in or have secured under long-term purchase contracts, power generation and transmission facilities throughout the West. These facilities provide the diversity of fuel and technology and location that has served SCPPA members well by providing constant and predictable electrical prices.

SCPPA members have made traditional investments in the areas of hydroelectric, nuclear, coal, and natural gas-fired generation. To meet the challenges and growing demand for energy needs, new investments in local base load and peaking natural gas-fired units will satisfy these needs and increase overall system reliability. **Planned expansion and re-powering projects through the year 2010 will add approximately 2,000 Megawatts of new gas-fired generation,** and will be built to either replace current third-party power contracts or to retire older less efficient units.

In addition to the traditional type of investments, renewable sources continue to be a key component for the future. New renewable projects will further diversify generation portfolios, and also benefit the environment through enhanced pollution control technologies. Investment by SCPPA members in renewable energy programs, have totaled nearly $70 million over the past five years. Through renewable investments, SCPPA members have adopted voluntary renewable portfolio standards similar to those required of IOUs. **By 2010, on a combined basis, SCPPA members expect to have 26% of their generation portfolios consist of renewables, including 8% new renewables and 18% in existing hydroelectric generation.** This illustrates how seriously SCPPA members take their obligation to serve and plan for the future of their customers.

SCPPA members are well positioned to serve and meet their customers' energy needs today and in the future. **SCPPA, in partnership with its members, is investing in the future** through the use of new investments in local base load, peaking natural gas-fired units, renewable energy, and prudent use of electricity.

PALO VERDE
OPERATIONS



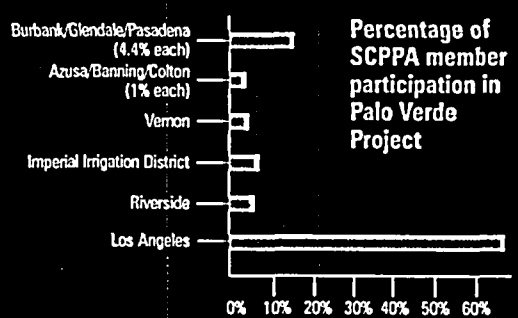
The steam generators in Unit 2 were successfully replaced during the fall of 2003. Plans are underway to replace the steam generators in Units 1 and 3 in 2005 and 2007 respectively.

PRODUCTION COST
(Operation and Maintenance plus Nuclear Fuel)

Calendar Year	Cents per kWh
1993	2.02
1994	1.93
1995	1.61
1996	1.45
1997	1.33
1998	1.28
1999	1.25
2000	1.25
2001	1.27
2002	1.28
2003	1.32

2003-2004 OPERATIONS

	Generation (Millions of MWHs)	Capacity Utilization (%)
Unit 1	9.3	84.8%
Unit 2	8.0	70.1%
Unit 3	10.1	92.6%
Aggregate	27.4	82.5%



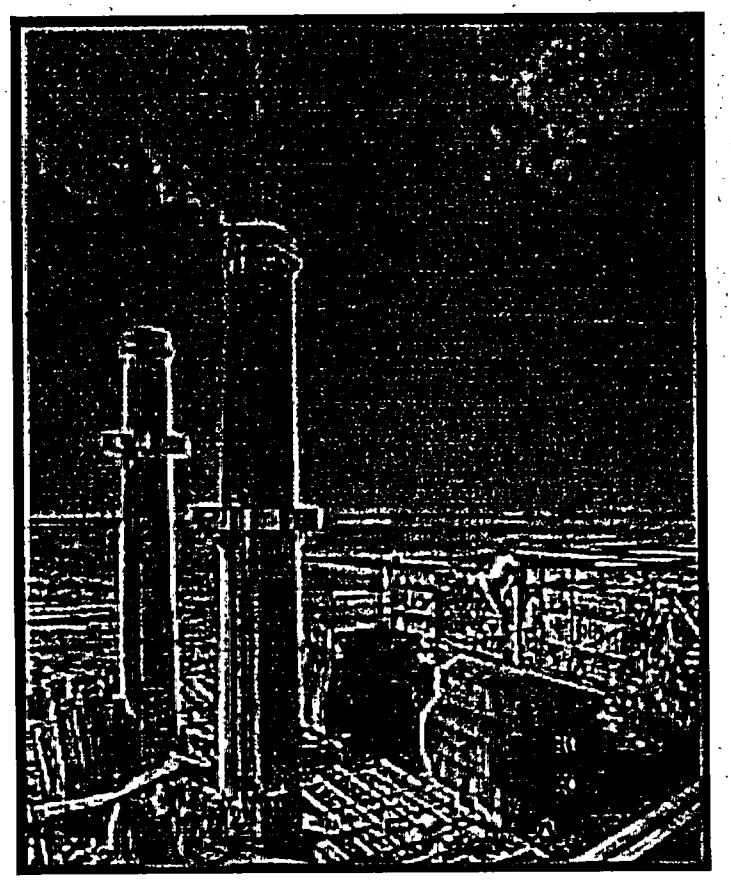
Percentage of SCPPA member participation in Palo Verde Project

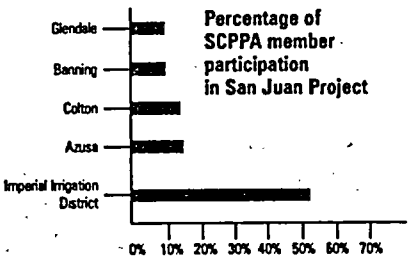
Five SCPPA participants own 41.8% of Unit 3 at the San Juan Generating Station, a coal-fired plant in New Mexico. A series of Interim Invoicing Agreements for fuel has led to high capacity factors and lower per unit fuel costs.

After two decades of surface strip mining at the adjacent coal mine, operations have transitioned to long-wall underground mining. The underground mine has reached steady state, completed the first long-wall move, and is building reserve inventory.

SAN JUAN

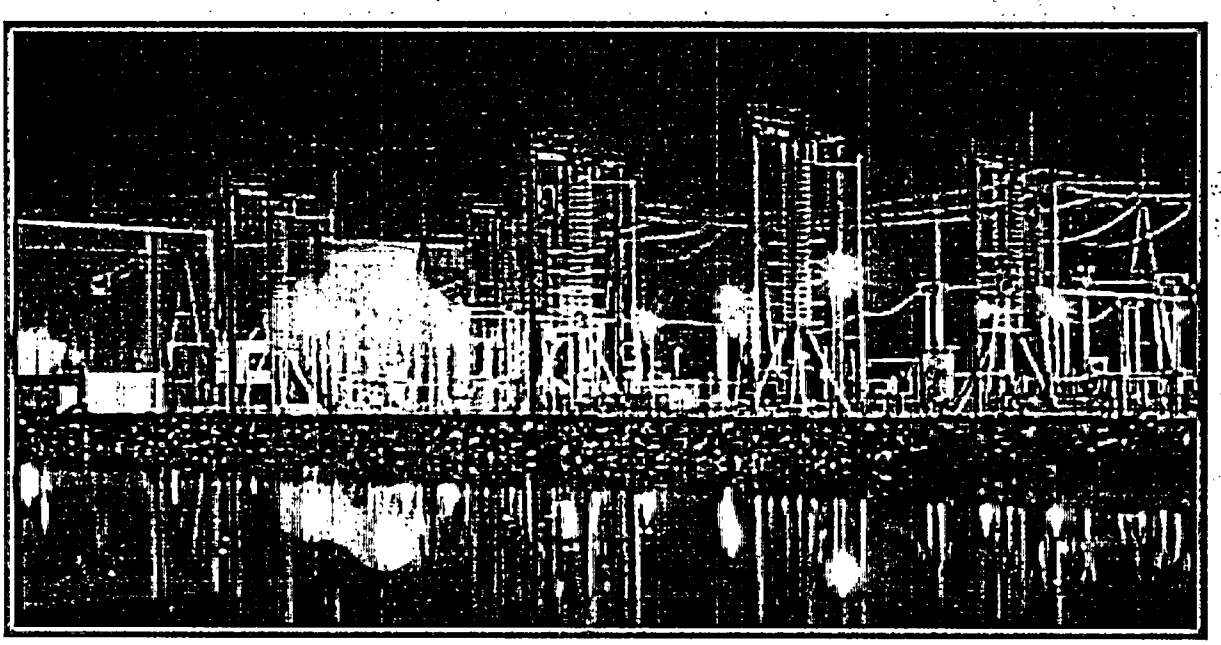
UNIT 3 OPERATIONS

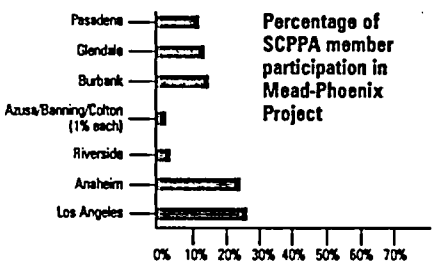




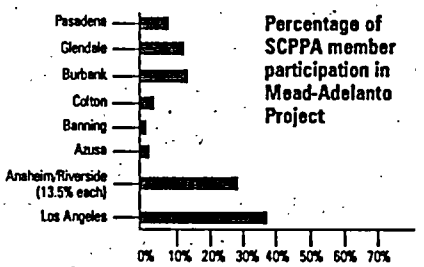
The two 500-kV transmission lines, which connect Phoenix to Las Vegas, and Las Vegas to Southern California, completed their seventh year of dependable operation for the nine SCPPA members who participate in the projects.

MEAD-PHOENIX/MEAD-ADELANTO TRANSMISSION PROJECTS

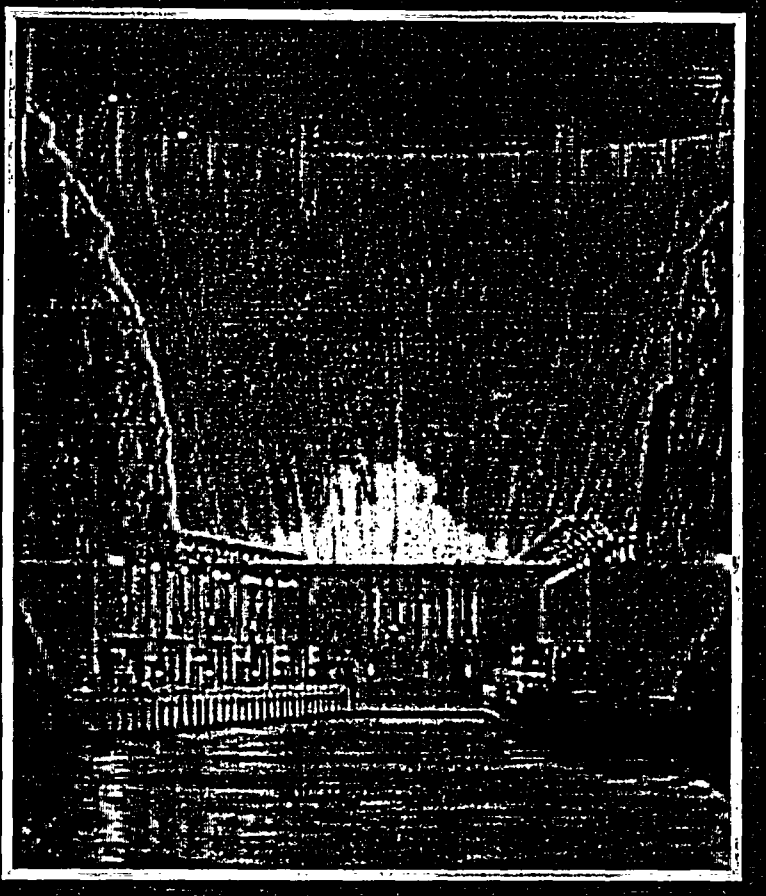




Percentage of SCPPA member participation in Mead-Phoenix Project

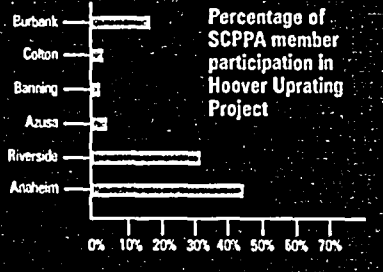


Percentage of SCPPA member participation in Mead-Adelanto Project



HOOVER

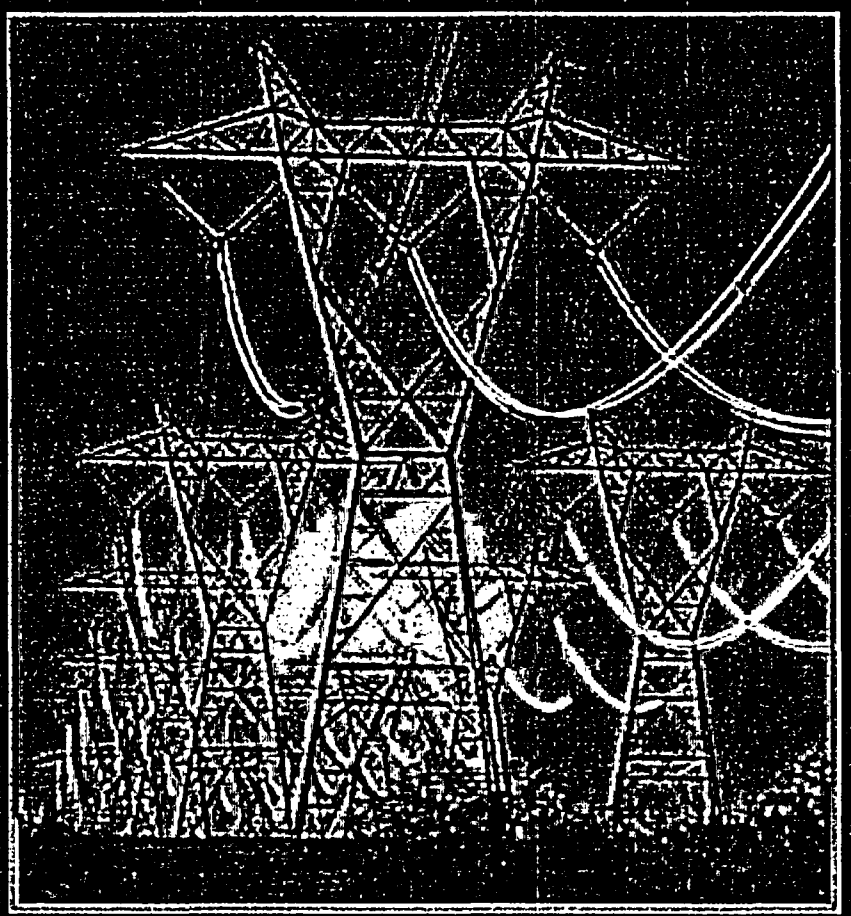
UPRATING PROJECT



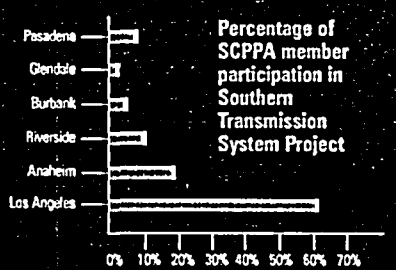
Percentage of SCPPA member participation in Hoover Uprating Project

The **Hoover Uprating Project** continues to provide six SCPPA members with low-cost, renewable energy (hydro). A SCPPA representative is active in the development of the Lower Colorado River Multi-Species Conservation Program.

STS Southern Transmission System

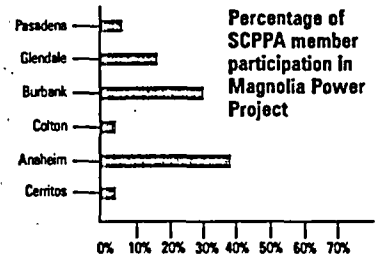


As usual, the STS operated with near-perfect availability (99.37%), delivering over 14 million MWHs to the six SCPPA members who are participants. The power comes 488 miles from the Intermountain Power Project, in Utah, over the ±500-kv DC line.



Percentage of SCPPA member participation in Southern Transmission System Project

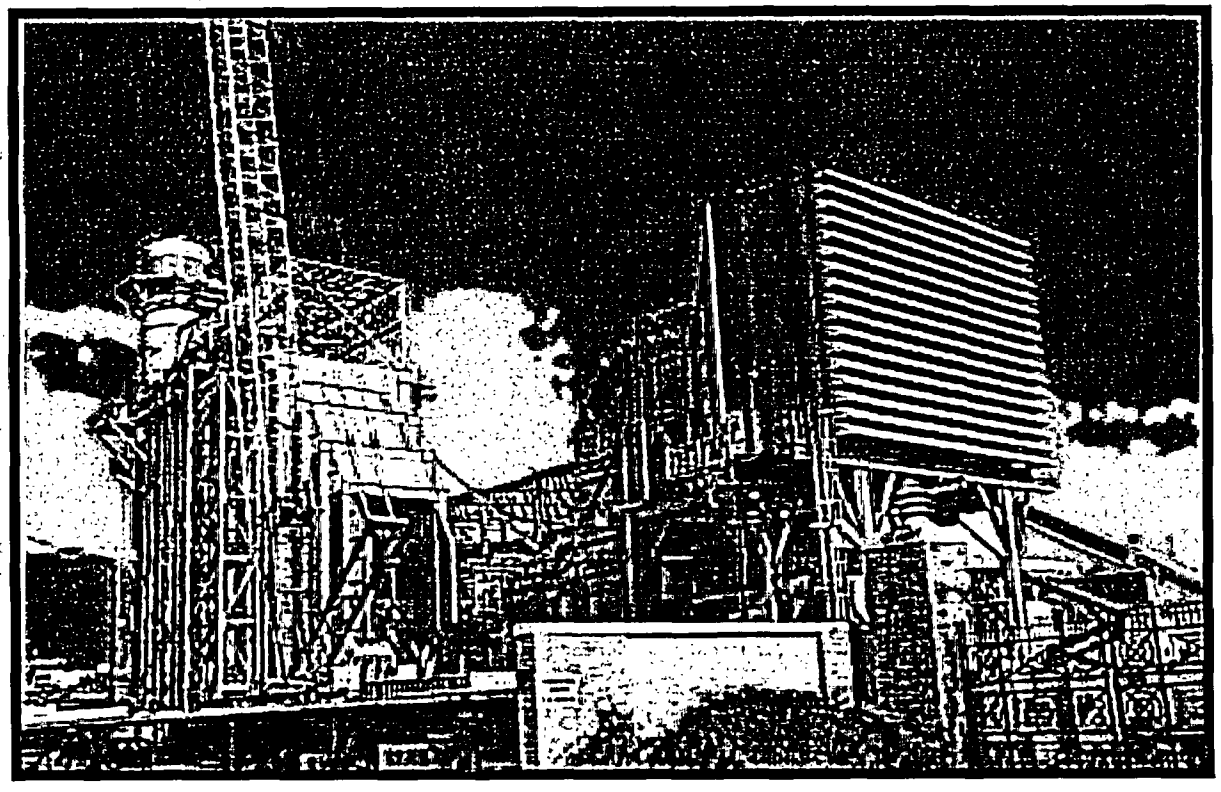
Construction is progressing on schedule on the **Magnolia Power Project**, a 240 megawatt natural gas-fired, combined cycle plant, located on the site of an existing plant in the City of Burbank. It will replace an older, less-efficient unit. The result will be more power from less fuel, with less pollution.



Percentage of SCPPA member participation in Magnolia Power Project

The plant is scheduled to be operational by late spring of 2005, and will be the first project to be wholly-owned by SCPPA members. The Participants are Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena.

MAGNOLIA
POWER PROJECT



FINANCING

Palo Verde Escrow Restructuring – Phase II

In August 2003, a second phase of the Palo Verde escrow restructuring was completed with respect to the Escrow Fund created for the Authority's Project Revenue Bonds, 1992 Refunding Series B and Power Project Revenue Bonds, 1992 Refunding Series C, and generated a gross benefit to SCPPA of $667,522. The transaction was designed to capitalize on a current low interest rate environment and the fact that the Authority had retained the rights to sell the securities in the Escrow Fund and to redeem certain of its Series 1992B Bonds, which previously had been escrowed to maturity. The overall transaction mechanics consisted of the liquidation of ten existing Refcorps securities and 17 State and Local Government Securities (SLGS) interest-bearing and zero coupon securities, amendment of the Float Agreement with respect to the Series 1992B Bonds cash flows, purchase of one U.S. Treasury Bill scheduled to mature on the September 2003 call date of the Series 1992B Bonds, and subscription of five SLGS for the non-callable Series 1992C Bonds. The restructuring was completed using a comprehensive competitive bid process that relied on the procurement of securities on a "security-by-security" basis. SCPPA entered into agreements with UBS Financial Services, Inc. and Public Financial Management, Inc. to execute the restructuring.

Mead-Adelanto/Mead-Phoenix Project Revenue Bonds, Series 2004A

In March 2004, SCPPA entered into two floating-to-fixed interest rate swaps. The swap provider for the transactions was UBS AG. The transactions consisted of $28.7 million and $96.0 million above-market forward-starting interest rate swaps for the Mead-Phoenix and Mead-Adelanto Projects, respectively. Under these transactions, SCPPA will pay UBS a fixed rate of 3.894% on the Mead-Phoenix swap and 3.890% on the Mead-Adelanto swap, and in exchange receive 65% of 1-month LIBOR. In addition, in exchange for paying an above-market fixed rate, SCPPA received upfront payments from UBS of a combined amount of $7.7 million to comply with a par-to-par restriction on the refunded bonds. The forward swaps hedged the refunding savings then available on existing fixed-rate bonds.

ACTIVITIES

In May 2004, SCPPA issued a $183,375,000 Project Revenue Bond Issue ($141,150,000 Mead-Adelanto 2004 Series A, $42,225,000 Mead-Phoenix 2004 Series A) for the principle purpose of providing for the payment and redemption of certain of the Authority's outstanding Mead-Adelanto Project Revenue Bonds, 1994 Series A and Mead-Phoenix Project Revenue Bonds, 1994 Series A. This synthetic refunding generated an expected total present value savings of $12.7 million, or 6.94% of the refunded par. The triple A-rated bonds were insured by Ambac Assurance Corporation and underwritten by UBS Financial Services, Inc.

The 1994 Mead-Adelanto Bonds and 1994 Mead-Phoenix Bonds were issued to refund certain of the Authority's outstanding Multiple Project Revenue Bonds, 1989 Series, which were issued to finance the costs of construction and acquisition of ownership interests or capacity rights in certain projects, including the Mead-Adelanto Project and the Mead-Phoenix Project, for the generation or transmission of electric energy. The 2004 Bonds are payable on a parity with the outstanding 1994 Bonds. The 2004 Mead-Adelanto Bonds are payable on a basis subordinate to the portion of debt service on the outstanding 1989 Bonds allocated to the Mead-Adelanto Project, and the 2004 Mead-Phoenix Bonds are payable on a basis subordinate to the portion of debt service on the outstanding 1989 Bonds allocated to the Mead-Phoenix Project.

Other Refundings and Transactions

SCPPA's Finance Committee continues to look for opportunities to lower financing costs through, for example, bond refundings and interest rate swaps. At fiscal year-end, refundings and/or interest rate swaps for the Southern Transmission Project, Series 1989 Multiple Project, and Magnolia Power Project Series A bonds were under consideration.

SCPPA'S FINANCE COMMITTEE CONTINUES TO LOOK FOR OPPORTUNITIES TO LOWER FINANCING COSTS THROUGH BOND REFUNDINGS AND INTEREST RATE SWAPS.

SCPPA

SCPPA's key objective is to provide low-cost, reliable power to its customers through strong local control over its operations. SCPPA remains committed to building and acquiring new generation assets for its members, with a particular commitment to renewable generation. In order to realize these goals, SCPPA and its members speak in a common voice on vital energy issues in Sacramento and Washington, D.C., providing greater impact on issues that affect the public power community.

The second year of the 2003-04 legislative session found the Democratic-dominated California State Legislature facing newly-elected Republican Governor Arnold Schwarzenegger, following the recall by voter referendum of Gray Davis. Recognizing that a new Administration brings its own agenda to the legislative debate, SCPPA immediately called upon its existing relationships with staff for the new Governor. In doing so, the transition from one Administration to the new became as seamless as possible and ensured SCPPA's voice was heard from the start of the new Administration. Energy policy came into focus near the end of session, after the Governor faced other more urgent priorities. Legislation to encourage the use of solar power generation took center stage during the session's final week, with both the Governor and the Senate Democrats introducing separate bills with similar subject matter. Both pieces of legislation targeted the reduction of electricity purchases by providing alternative solar energy during peak demand, while providing rebates to encourage installation of grid-connected solar energy systems in new homes. Both bills died: the Administration's bill failed in the Assembly Utilities and Commerce Committee and the Senate version stalled on the Senate floor when a key issue failed to be resolved. The Governor's Office has signaled that it may revive legislation to encourage installation of solar energy to mitigate peak demand in the next legislative session.

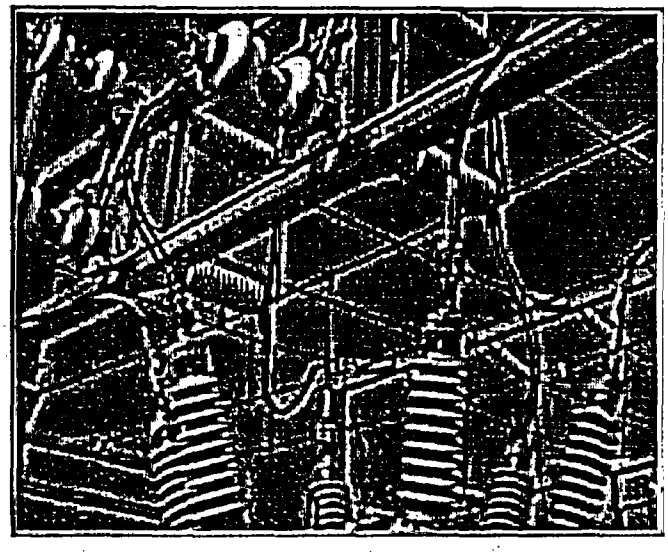
SCPPA, along with the California Municipal Utilities Association (CMUA) and other municipal utilities, sponsored Assembly Bill 426 (AB 426), which would have prohibited the California Public Utilities Commission (CPUC) from imposing an exit fee on customers of a municipal utility if the customer's service location had not previously been served by an investor-owned utility (IOU). The bill was authored by then-Republican Assembly member now Senator Dave Cox and garnered strong bi-partisan support from both Chambers. However, the bill faced a roadblock in the Assembly Utilities and Commerce Committee and became inactive. This issue of exit fees is also pending before the CPUC; if an unfavorable decision is reached in that forum, AB 426 as written or a modified version sponsored by CMUA will likely emerge in the 2005 legislature. Senate Bill 1478 (SB 1478) was introduced by Democrat Senator Byron Sher. SB 1478 reflected the new Governor's commitment to accelerate, from 20% in 2017 to 20% in 2010, the amount of renewable generation required by the state's investor-owned utilities. SCPPA worked with CMUA and representatives of the environmental community to craft language amended into SB1478, preserving local control while encouraging increased public power investment in renewable. As the final version of the bill did not meet Governor Schwarzenegger's goal, a vibrant competitive renewable energy market, the bill was vetoed on September 24, 2004.

California's municipal utilities (and cities seeking to start a municipal utility) continue to face legislative challenges to local control. Assembly Bill 2499 (AB 2499) would have required new consumer-owned utilities to meet the same resource adequacy requirements as IOUs, including reserve capacity. The bill provided that the California Energy Commission (CEC), not the local government, approve long-term resource plans before a new municipal utility commences operation. AB 2499 would have also permitted any person or entity – irrespective of whether that person or entity lives in the community – to challenge the adequacy of the long-term resource plans submitted to the CEC by a municipal utility. The bill also would have imposed exit fees on the new municipal customers. The bill failed passage on the Senate Floor after an onerous, related amendment was added to the bill.

Each year legislative changes and challenges provide SCPPA the opportunity to bring its message to the elected of the California State Assembly and Senate. For the new 2005-06 legislative session, SCPPA's legislative direction remains purposeful and focused as in the past: protection of local control and the interests of approximately two million customers we serve.

LEGISLATIVE REPORT

During the second session of the 108th Congress, H.R. 6, *the Energy Policy Act of 2003,* continued to be the focus of SCPPA's legislative activity in Washington, D.C. Much of SCPPA's legislative effort was spent convincing its Congressional delegation that the electricity title in the bill provided no net benefits to consumers in Southern California, and that additional provisions were needed. SCPPA advocated inclusion of provisions in H.R. 6 that would strengthen the electricity system in California and provide protection for its consumers. For example, SCPPA worked for inclusion of federal reliability standards and language that would authorize voluntary – not mandatory– regional transmission organizations (RTO). SCPPA also spent much of its political capital trying to convince Congress not to include provisions in the bill which would erode public power's local control – such as new Federal Energy Regulatory Commission (FERC) authority to regulate public power's transmission facilities or order refunds of short-term wholesale power sales by large consumer-owned utilities. Concurrently, SCPPA worked to address concerns that the California Independent System Operator (CAISO) was moving more quickly with market protocols and rules than those in the rest of the Western market. SCPPA worked with Senators Dianne Feinstein (D-CA) and Barbara Boxer (D-CA) on efforts to tie provisions in the bill that would delay FERC's Standard Market Design (SMD) proposal for 18 months to California's Market Design 2002 (MD 02) initiative. SCPPA also worked to garner House support, for this linkage, with Rep. Duncan Hunter (R-CA) taking a lead on a letter to FERC Commissioner Pat Wood encouraging the two market design efforts to be "synchronized" so California did not create an electricity market separate and different from its neighboring states. Ultimately, however SCPPA's proposed statutory language – linking the SMD delay to MD02 efforts – was not included in the final energy bill.



SCPPA members also vigorously worked to balance the impact of repeal of the Public Utility Holding Company Act (PUHCA), a 1935 law designed to protect investors and consumers against the risks of holding company diversifications and other transactions, with the addition of consumer protections. Senators Boxer and Feinstein waged an aggressive floor fight with fellow Democrats on our behalf, but, unfortunately, those who supported PUHCA repeal (backed by the powerful holding company lobby) prevailed. In November of 2003, when the House-Senate conference committee released the final energy bill, most observers expected it to pass and go to the President for his signature before the end of the year. The House passed the $31 billion energy bill relatively easily by a vote of 246 to 180. However, the legislation ran into a procedural and substantive roadblock in the Senate based, in large part on the MTBE waiver and the overall cost of the bill. Sen. Feinstein helped lead the opposition to provisions to limit the liability of the makers of the gasoline additive Methyl Tertiary-Butyl Ether (MTBE), a key contaminate of California's groundwater in the Senate. Feinstein, and others, worked to gain Republican support from her Northeast colleagues to filibuster H.R. 6 when it came to the Senate floor. Senate Majority Leader Bill Frist (R-TN) and Energy and Natural Resources Committee Chairman, Pete Domenici (R-NM), won the support of only 58 Senators, two short of the 60 needed to advance the bill. Both Senators Feinstein and Boxer voted against the bill, in part because of the MTBE provisions, but also because of their objections to the electricity provisions in the bill, many of which mirrored SCPPA's concerns.

With the comprehensive energy bill stalled for almost a year in the Senate, Members of Congress sought other vehicles to move certain "pet" energy provisions, in the waning days of the 108th Congress. Portions of the energy tax title from H.R. 6 were included in two separate tax bills – the corporate tax bill (H.R. 4520 referred to as the

(continued on page 18)

Marcie L. Edwards
General Manager
Anaheim Public Utilities Department

Joseph F. Hsu
Director of Utilities
City of Azusa Light & Water

Paul Toor
Director of Public Works/ Assistant City Manager
City of Banning

City of Anaheim

Anaheim Public Utilities celebrated a benchmark in 2004 with the 125th anniversary of its water utility. The City's electric utility was incorporated in 1894. Today, the City of Anaheim is the only community in Orange County with a publicly owned water and electric utility. Anaheim residents enjoy rates that are significantly lower than the electric rates charged in neighboring communities, reliable electric service, and an array of more than 40 targeted energy efficiency programs. In the coming years, Anaheim Public Utilities will continue to work to the best advantage of Anaheim consumers. With a strong, creative management team, sound resource and financial planning, and a cadre of experienced and dedicated employees, we will maintain sharp focus on meeting the community's long-term power needs and offer measures that will help our customers make efficient use of electricity.

City of Glendale

Incorporated in 1906, Glendale purchased its electric utility in 1909, obtaining power from outside suppliers. It received its first power from Hoover Dam in 1937 and inaugurated the first unit of its own steam generating plant in 1941. Now called the Grayson Power Plant, this facility today has eight generating units. Glendale continues to purchase 85-90% of its power from outside resources.

City of Azusa

The City's electric utility was incorporated in 1898 when it purchased the assets of a private utility on the brink of bankruptcy. The foresight and planning of those early pioneers continues to be the cornerstone of today's Azusa Light and Water. The City continues its tradition of diligent and prudent planning of system improvements and resource procurement to serve its citizens/owners. In order to serve the growing city's retail load, the Azusa Light and Water planned, engineered, and constructed a new electric distribution substation, Kirkwall Substation, which was energized on April 21st, 2004 to provide enhanced service reliability and operation flexibility. Azusa Light and Water continues to be recognized as one of the proactive leaders in promoting energy and water conservation and efficiency programs and renewable energy in the State, earning the recognition of CMUA 2004 Community Service/ Resource Efficiency Award for Best Management Practices for the "Drought Resistant Plant (DRiP) Program."

Imperial Irrigation District

IID entered the power industry in 1936 and today serves a peak load of 870 MW with 1,050 MW of generating resources. Among IID-owned resources are 24 MW of low head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, and 162 MW of peaking gas turbines. In addition to IID's share of SCPPA resources comprising 104 MW at San Juan and 14 MW at Palo Verde, IID has 200 MW of geothermal, renewable resources under long-term purchase contracts.

City of Banning

Established in 1913, the Banning electrical system now serves an area of approximately 22 square miles. Banning's energy resource base includes portions of coal, nuclear and hydro generating plants, which provide the majority of electricity required to meet its summer peak load of 46 MW. The City supports clean energy and it committed to implementing renewable resource programs. The Utility is dedicated to continue providing quality service to its customers in a reliable manner, and at reasonable rates.

Los Angeles Department of Water and Power

Providing service for more than a century, the Los Angeles Department of Water and Power began delivering water to the city in 1902, and with the water came power. In 1916, LADWP first delivered electicity to the city purchased from the Pasadena Municipal Plant. A year later, LADWP began generating its own hydroelectric power at the San Francisquito Power Plant No. 1. After purchasing the remaining distribution system of Southern California Edison within the city limits in 1922, LADWP became the sole water and electricity provider for the City of Los Angeles. It is now the largest municipally owned electric utility in the nation, serving a population of 3.8 million residents over a 465 square mile area. LADWP remains on firm financial footing and serves as a valuable asset to the City of Los Angeles.

Ignacio R. Trancoso
Director of Utilities
Glendale Water and Power

Glenn O. Steiger
Manager, Energy Department
Imperial Irrigation District

Ronald O. Vazquez
Chief Financial Officer
Los Angeles Department of Water and Power

Ronald E. Davis
General Manager
Burbank Water and Power

Art Gallucci
City Manager
City of Cerritos

Jeannette Olko
Utility Director
City of Colton

City of Burbank

Burbank Water and Power (BWP) began serving both water and electric customers in 1913 and installing on-site power generation in the 1940s. Today it operates about 182 MW of gas-fired capacity and holds 100 MW of jointly owned coal, nuclear and hydro capacity. BWP is the project manager and operating agent for the Magnolia Power Project (MPP). MPP has a nominal capacity of 242 MW and a peaking capacity of 310 MW. BWP will receive 31 percent of the power from MPP. Other SCPPA participants include: Anaheim, Cerritos, Colton, Glendale, and Pasadena.

City of Cerritos

The first new member to join Southern California Public Power Authority in over 20 years, the City of Cerritos is preparing to serve the electricity demands of its residential and business communities. To further these efforts, Cerritos is participating in the development of the Magnolia Power Project. With the goal of providing a stable and affordable supply of electricity, Cerritos intends on developing a diverse portfolio of power to be delivered as competitively and economically as possible.

City of Colton

The Colton Municipal Utility was established in 1895 and has provided our customers with reliable and affordable electric service for over one hundred years. We are proud of this accomplishment, and have positioned ourselves to continue this high level of service over the next century. By making firm commitments for resource planning, system maintenance, community involvement, and employee enrichment, we believe this pledge to our customers will provide the value that they deserve.

SCPPA MUNICIPALITIES

City of Pasadena

PWP began providing electricity in 1906 and began delivering water in 1912. The city built its first electric generating steam plant in 1907 and took over operation of its municipal street lighting from Edison Electric. In 1909, Pasadena began the extension of its operations to commercial and residential customers that resulted in the replacement of all Edison Electric service in the city by 1920. While a lot has changed over the years, PWP's strong connection to its customer/owner base remains constant. Today, PWP provides electric service to more than 59,000 metered accounts over a 23 square-mile service area at rates that are among the lowest in Southern California. PWP's success is a result of its commitment to remain a valued community asset, an exceptional employer, and a partner in Pasadena's prosperous future.

City of Riverside

The City of Riverside Public Utilities provides electric service to more than 100,700 metered accounts, representing a service area population of over 277,000. The utility is committed to the highest quality water and electric services at the lowest possible rates to benefit the community. To maintain their commitment, Riverside has positioned itself well in the electric market by utilizing short, mid, and long term contracts from power suppliers, and by building power generation sources within its own power grid, including a 40 MW power plant in 2002 and the construction of a 99.6 MW power plant scheduled for operation in late 2005. Riverside's portfolio includes 27 MW of renewable resources which includes 400 kW of photovoltaic systems within the city.

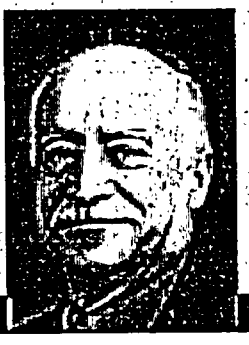
City of Vernon

Vernon's Utilities Department began serving industrial customers in 1933, with completion of its diesel generating plant. In addition to its own power from diesel units and gas turbines, Vernon also receives power from Palo Verde, Hoover, and various suppliers. Vernon is in the process of constructing a 134 MW gas-fired combined cycle power plant within its city limits. Vernon resides within the California Independent System Operator (CAISO) Control Area and is a Participating Transmission Owner.

Phyllis E. Currie
General Manager
Pasadena Water and Power

David H. Wright
Interim Public Utilities Director
City of Riverside

Charles W. Montoya
City of Vernon



"JOBS" bill or the *"FSC/ETI"* bill) and the middle-class tax relief bill (H.R. 1308, the *"Relief for Working Families Tax Act of 2004"*). Relevant to SCPPA members were provisions that expanded and extended, for two years, the 1.8 cents per kWh Production Tax Credit (PTC) for private developers to include open-loop biomass, geothermal energy, solar energy, small irrigation power and municipal solid waste (in addition to wind and closed-loop biomass, which are both included in the definition under current law.) Neither of the bills, however, included the "tradable tax credit" or the "tax credit bond" proposal sought by public power to incentivize development of renewables by consumer-owned systems. The tradable tax credit was not included in the final bill because of strong opposition from Ways and Means Committee Chairman Bill Thomas (R-CA) and the Treasury Department. The tax credit bond proposal was not considered because it was a "new" proposal (i.e. not in either the House or Senate bills) and, therefore, was ruled non-germane. Noteworthy is that the expiration date of the PTC in the JOBS bill is January 1, 2006. Given the short extension, SCPPA and others in public power will have an opportunity to push for comparable tax incentives, such as the tax credit bond, when the PTC comes up for renewal again next year.

Another legislative priority was SCPPA's effort to reauthorize and reform the Department of Energy's (DOE) Renewable Energy Productive Incentive (REPI) program, which provides incentives to public power utilities to build clean renewable energy facilities. SCPPA members worked successfully with Rep. Mary Bono (R-CA), an original sponsor of the legislation, and others, to get the bill included in H.R.6. SCPPA continues to urge passage of stand-alone REPI reauthorization legislation during the lame-duck session, possibly in the Omnibus FY05 Appropriations bill. In addition, SCPPA members actively participated in an American Public Power Association (APPA) Washington, D.C. REPI "fly-in" to lobby the Hill and the Administration to increase funding for this program. As a result, Reps. Bono and Adam Schiff (D-CA) circulated a bipartisan "California-only" letter, which garnered support from 25 members of the delegation, to Energy and Water Development Subcommittee Chairman David Hobson (R-OH) and Ranking Member Peter Visclosky (D-IN) in support of at least $13 million in increased REPI funding in FY 2005. These efforts succeeded in increasing the program's funding by 25% in the House, from $4 million to $5 million. Reps. John Doolittle (R-CA), a member of the Energy and Water Development Appropriations Subcommittee, along with Senior Republican Rep. Duncan Hunter (R-CA) were also instrumental in this effort, on SCPPA's behalf. Sen. Feinstein, a member of the Senate Energy and Water Development Appropriations Subcommittee, also assisted public power in making its case for increased REPI funding by sending a letter to Appropriations Chairman Pete Domenici (R-NM) and Ranking Member Harry Reid (D-NV), requesting at least $13 million in FY05 REPI funding. No final resolution on the REPI funding has been reached in the Senate, as Congress has not completed work on the final FY 2005 Energy and Water Appropriations bill and may very well push this work over to the 109th Congress.

SCPPA continues to work with Senators Feinstein and Boxer, and other Western Senators, on the question of whether increased security costs at Bureau of Reclamation facilities, such as Hoover Dam, will remain a federal obligation or whether a portion of those costs must be reimbursed by power customers, as proposed in the Bureau of Reclamation's FY 2005 budget request. SCPPA hopes to get legislative language included in the Omnibus Appropriations bill that would halt the Bureau's new proposal for at least one year.

With the November 4 elections completed, the President and leaders of the Republican-dominated Congress are beginning to flesh out their legislative priorities for the 109th Congress, which begins January 20th. With a larger majority in both the House and the Senate, Members have indicated they plan to refocus their attention on passage of an energy bill, overhaul of the Telecommunication Act of 1996, as well as tackle key environmental issues such as reforming both the Clean Air Act (CAA) and the Endangered Species Act (ESA). All of these will be of interest to SCPPA members and their customer-owners.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED FINANCIAL STATEMENTS
INDEX

The following discussion and analysis of the financial performance of each of the projects in which the Southern California Public Power Authority (the "Authority" or "SCPPA") has interests, provides an overview of the projects' financial activities for the fiscal year ended June 30, 2004. Descriptions and other details pertaining to the projects are included in the Notes to Combined Financial Statements. Please read this discussion and analysis in conjunction with the Authority's Combined Financial Statements, which begin on page 42.

The Authority is a joint powers authority whose primary purpose has been to provide joint financing for its member agencies that consist of eleven municipal electric utilities and one irrigation district in California. On a combined basis, these entities provide electricity to more than 2 million retail electric customers. A Board of Directors (the "Board") governs the Authority, which consists of one representative from each member agency.

The Authority has interests in the following projects:

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, a 5.56% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA") to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS"), which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

Mead-Phoenix and Mead-Adelanto Projects – As of August 4, 1992, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project ("Mead-Phoenix"), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component.

As of August 4, 1992, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project ("Mead-Adelanto"), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund and commercial operations commenced in April 1996. LADWP serves as the operations manager of Mead-Adelanto.

Projects' Stabilization Fund – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits within SCPPA project purposes. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust.

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

Participant Ownership Interests – The Authority's participants may elect to participate in the projects. As of June 30, 2004, the members have the following participation percentages in the Authority's interest in the projects:

Partidpants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project
City of Los Angeles	67.0%	59.5%	–	24.8%	35.7%	–	–
City of Anaheim	–	17.6%	42.6%	24.2%	13.5%	–	38.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%	–	–
Imperial Irrigation District	6.5%	–	–	–	–	51.0%	–
City of Vernon	4.9%	–	–	–	–	–	–
City of Azusa	1.0%	–	4.2%	1.0%	2.2%	14.7%	–
City of Banning	1.0%	–	2.1%	1.0%	1.3%	9.8%	–
City of Colton	1.0%	–	3.2%	1.0%	2.6%	14.7%	4.2%
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%	–	31.0%
City of Glendale	4.4%	2.3%	–	14.8%	11.1%	9.8%	16.5%
City of Cerritos	–	–	–	–	–	–	4.2%
City of Pasadena	4.4%	5.9%	–	13.8%	8.6%	–	6.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The Authority has entered into power sales and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output or transmission service, as applicable. The participants are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner that will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding.

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036

Critical Accounting Policies

Method of Accounting – The accounting records of the Authority are maintained in accordance with accounting principles generally accepted in the United States of America. In prior years, the Authority, as a government-owned utility, applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB) which were not in conflict with statements issued by GASB. Effective July 1, 2002, the Authority changed its election under the guidance in GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, to follow all GASB statements and only FASB statements and interpretations issued before November 30, 1989. See Note 2 to the combined financial statements discussing the results of this change in accounting principle.

Costs Recoverable – The Authority's billing amounts to the participants are determined by its Board of Directors and are subject to review and approval by the participants. Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. The difference between billings and the Authority's expenses calculated in accordance with generally accepted accounting principles are deferred as costs recoverable or payable in future periods and are presented as net assets (deficit). It is intended that the deferred amounts will be recovered through billings for repayment of principal on the related bonds.

Investment Policy and Controls – The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. seq. of the California Government Code, Indentures of Trust, instruments governing financial arrangements entered into by the Authority to finance and operate Projects, and the Authority's Investment Policy. The Indentures of Trust authorize the establishment of specific Project funds and accounts, specify how monies are to be applied, and name third party Trustees.

Funds available for investment include proceeds from bonds and notes sales, payments from the participants, maturities of previous investments, earnings, exchanges of securities and interest from swap agreements. Funds are managed and invested on a separate accounting basis and principal and earnings are credited and allocated to designated funds or accounts as outlined in each Project's Indenture of Trust, or in the Projects' Stabilization Fund which was established by a Board Resolution.

The three fundamental criteria in the investment program, ranked in accordance of importance, are: safety of principal, liquidity and return. An exception to the preceding criteria is made for the Palo Verde Nuclear Decommissioning Trust Funds, as liquidity will not be a factor until 2023. The investment criteria for the Decommissioning Trust Funds, in order of importance, is as follows: safety, return, and liquidity.

Debt Management Program

The Authority's financing goal is to obtain the lowest prudent rates of interest on debt issues and to issue debt in the most cost-effective manner. On a combined basis, SCPPA reduced its cost of capital by 30 basis points to 4.76%, since June 30, 2003. In addition, the Authority will continue to utilize debt management strategies that reduce the overall cost of borrowing for its members. In general, the Authority issues new money debt and refunding debt on either a negotiated or competitive basis as determined by the Board. A minimum net present value savings of 5%, as a percent of the refunded par amount, is the general target when determining the potential to refund existing Authority debt. The Authority may also use interest rate swaps or other derivative products to help meet important financial objectives.

Jointly Owned Utility Plant

The Authority owns interests in several generating stations and transmission systems for which each participant has provided its own financing. Under these arrangements, a participating member has an undivided interest in a utility plant and is responsible for its proportionate share of the costs of construction and operation and it is entitled to its proportionate share of the energy produced. All utility plant of the Authority with the exception of the Magnolia Power Project is jointly owned. The related cost and accumulated depreciation for these jointly-owned projects has been reflected in each project's financial statements in utility plant. Additionally, the Authority's share of expenses for each project is included in the statements of revenues, expenses, and changes in net assets (deficit) as part of operations and maintenance expenses.

Using This Financial Report

This annual financial report consists of a series of financial statements and reflects the self-supporting activities of the Authority that are funded primarily through the sale of energy and transmission services to member agencies under project specific "take or pay" contracts that require each member agency to pay its proportionate share of operating and maintenance expenses and debt service with respect to such projects.

Combined Statements of Net Assets (Deficit), Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit), and Combined Statements of Cash Flows

The Combined Financial Statements provide an indication of the Authority's financial health. The Combined Statements of Net Assets (Deficit) include all of the Authority's assets and liabilities, using an accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes and which assets are restricted as a result of bond covenants and other commitments. The Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit) report all of the revenues and expenses during the time periods indicated. The Combined Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income, cash payments for bond principal payments, and capital additions and betterments.

Palo Verde Project
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 164,943	$ 183,818
Investments	682,699	674,924
Cash and cash equivalents	160,455	105,142
Other	13,955	14,658
	$ 1,022,052	$ 978,542
Liabilities and Net Assets		
Long-term debt	$ 569,050	$ 609,150
Current liabilities	125,057	114,030
	694,107	723,180
Net assets (deficit):		
Invested in capital assets, net of related debt	(451,167)	(469,233)
Restricted net assets	757,558	706,613
Unrestricted net assets	21,554	17,982
Total net assets	327,945	255,362
	$ 1,022,052	$ 978,542
Revenues, Expenses and Changes in Net Assets		
Operating revenues	$ 164,884	$ 180,529
Operating expenses	(63,496)	(73,650)
Net operating income	101,388	106,879
Investment income	14,144	96,885
Debt expenses	(42,949)	(47,941)
Increase in net assets	72,583	155,823
Beginning balance of net assets	255,362	99,539
Ending balance of net assets	$ 327,945	$ 255,362

Net Assets – The Palo Verde Project's Net Assets increased by $72.6 million, mainly due to a $43.5 million increase in Assets and a decrease in Liabilities of $29.1 million. The increase in the Assets of the Project is primarily due to additional Participant contributions to the Deposit Installment Escrow Fund under a debt-restructuring plan adopted by the Board through a resolution in 1998 to increase the competitiveness of the Palo Verde Project by accelerating the repayment of the Project's debt. Under the debt-restructuring plan, the billings to the Palo Verde Project Participants were increased by approximately $65 million each year through June 30, 2004.

During the fiscal year, the Authority restructured the 1992 B & C Escrow Restructuring Account, which resulted in a net gain of $572,000 after expenses, which was deferred and is being amortized over the life of the related bonds (see Note 5 of the Notes to Combined Financial Statements).

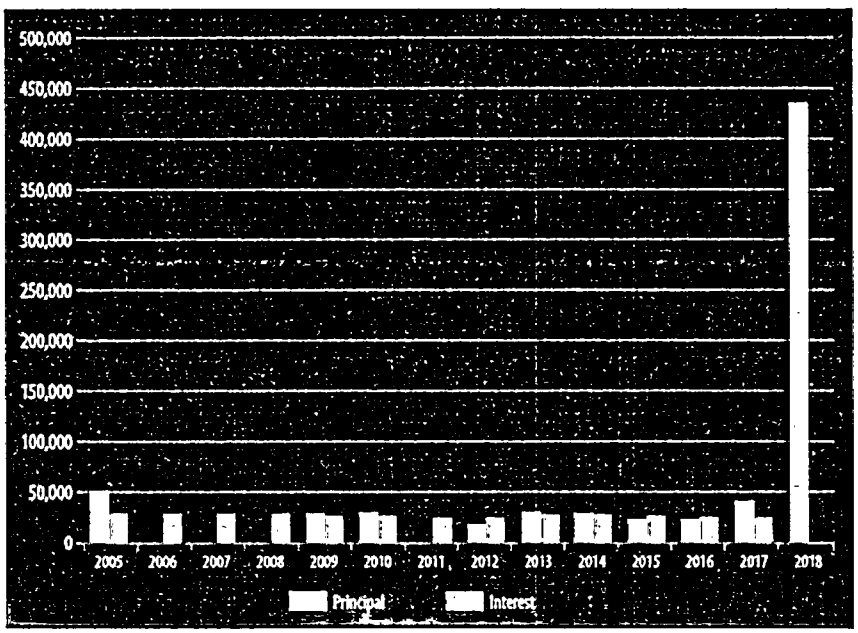
The decrease in Liabilities is primarily due to a decrease in long-term debt of $40.1 million as a result of principal bond maturities and the amortization of the bond discounts, premiums and losses on refunding on the related debt, offset by an $11 million increase in current liabilities mainly due to a $9.7 million increase in payable to Participants resulting from overbilling during the fiscal year.

In September 1998, the Project participants resolved to transfer any overcollection, renewal and replacement excess funds or surplus amounts through June 30, 2004 into the Project's reserve account. On November 20, 2003, the Authority adopted a resolution to utilize amounts on deposit in the reserve account to pay a portion of the operating and maintenance expenses of the Project starting July 1, 2004.

Long-term Debt – The Authority financed the acquisition of the assets of the Palo Verde Project through the issuance of revenue bonds. Currently, capital additions to the Project are financed from revenues received from participants.

The following graph provides an indication of the principal and interest payments on the Palo Verde Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2017-2018. Interest is reflected on an accrual basis.

Palo Verde Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Investment Income – The decrease in the PV investment income of $82.7 million is primarily due to the decline in the market value of Escrow accounts as a result of the upward trend in interest rates during the last quarter of the fiscal year.

Southern Transmission System Project (STS)
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 342,156	$ 361,785
Investments	56,361	58,802
Cash and cash equivalents	41,034	37,936
Other	23,519	23,001
	$ 463,070	$ 481,524
Liabilities and Net Deficit		
Long-term debt	$ 795,222	$ 807,669
Current liabilities	49,524	40,229
	844,746	847,898
Net assets (deficit):		
Invested in capital assets, net of related debt	(473,464)	(466,659)
Restricted net assets	99,459	100,939
Unrestricted net deficit	(7,671)	(654)
Total net deficit	(381,676)	(366,374)
	$ 463,070	$ 481,524
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 72,618	$ 82,229
Operating expenses	(33,371)	(33,433)
Net operating income	39,247	48,796
Investment income	3,044	6,131
Debt expenses	(57,593)	(62,592)
Extraordinary loss on debt refunding	–	(2,484)
Increase in net deficit	(15,302)	(10,149)
Beginning balance of net deficit	(366,374)	(356,225)
Ending balance of net deficit	$ (381,676)	$ (366,374)

Net Deficit – The Net Deficit in STS increased in 2004 by $15.3 million due to an $18.4 million decrease in Total Assets and a decrease in Liabilities of $3.1 million. The decrease in Total Assets consists mainly of the scheduled allowance in accumulated depreciation of $19.6 million.

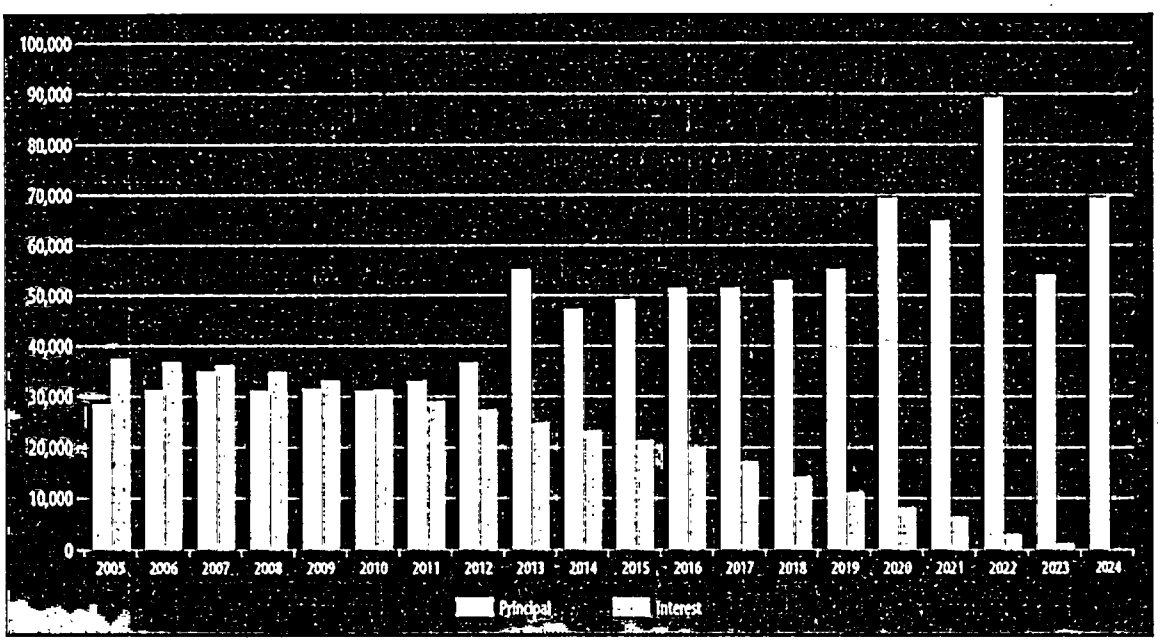
The decrease in Liabilities of $3.1 million is due to the following:

- a decrease of $12.4 million in long-term debt due to maturities net of amortization of bond discounts, premiums and losses on refunding, and
- an increase of $9.3 million in current liabilities mainly due to this fiscal year's overbilling.

The Net Deficit of $382 million at June 30, 2004 consists of non-cash expenses, which are not billed to the participants but are required to be recorded as expenses under generally accepted accounting principles. These non-cash expenses are primarily comprised of depreciation on utility plant, amortization of debt related expenses, amortization of bond premiums and discounts, and losses on refundings. These costs will be recovered at the time the Authority collects revenues to pay the principal portion of debt service costs.

Long-term Debt – The Authority acquired the STS assets through the issuance of revenue bonds. Capital additions are currently financed with revenues received from participants. Principal bond maturities redeemed on July 1, 2003 totaled $29.7 million.

Southern Transmission System Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



The graph above provides an indication of the principal and interest payments on the STS Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2023-2024. Interest is reflected on an accrual basis.

Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Operating Income – The decrease in STS operating income of $9.6 million is due mainly to the decrease in revenues as a result of lower debt service requirements in the current fiscal year.

Debt Expense – The decrease in STS debt expense of $4.9 million is largely due to the decrease in interest expense, amortization of bond discounts, and loss on refunding relating to the refunding of the 1993 A Subordinate Refunding Bonds by the 2003 A Subordinate Refunding Bonds.

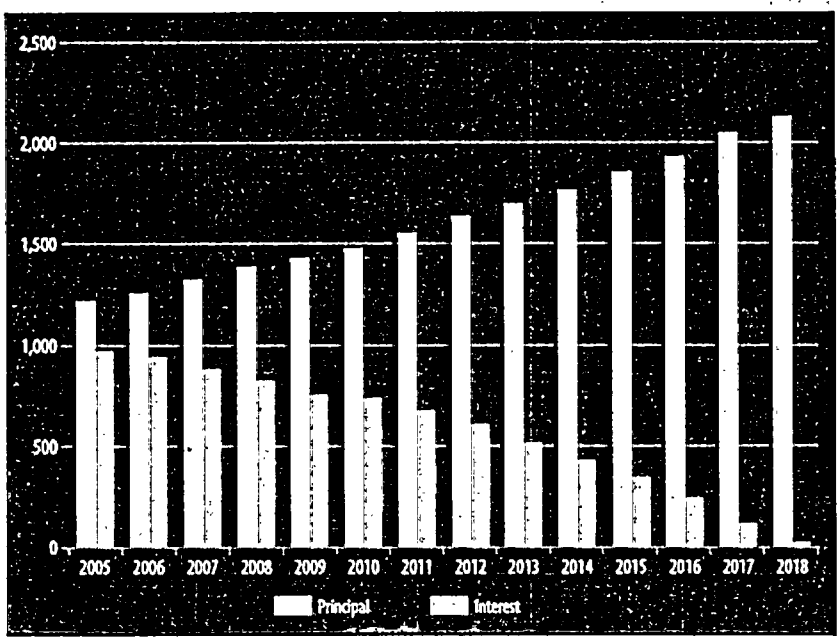
Hoover Uprating Project
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ –	$ –
Investments	2,918	500
Cash and cash equivalents	1,241	3,726
Other	19,400	20,674
	$ 23,559	$ 24,900
Liabilities and Net Assets		
Long-term debt	$ 18,575	$ 19,404
Current liabilities	1,537	1,643
	20,112	21,047
Net assets:		
Invested in capital assets, net of related debt	–	–
Restricted net assets	2,104	2,699
Unrestricted net assets	1,343	1,154
Total net assets	3,447	3,853
	$ 23,559	$ 24,900
Revenues, Expenses and Changes in Net Assets		
Operating revenues	$ 2,554	$ 2,330
Operating expenses	(2,331)	(2,381)
Net operating income	223	(51)
Investment income	18	73
Debt expenses	(647)	(331)
Extraordinary loss on debt refunding	–	–
Decrease in net assets	(406)	(309)
Beginning balance of net assets	3,853	4,162
Ending balance of net assets	$ 3,447	$ 3,853

Net Assets – The Net Assets of the Hoover Uprating Project decreased by $406,000. The net decrease is primarily due to a decrease in the Advances for capacity and energy balance. This balance consists of $19 million in advances provided by the Participants to the Hoover Power Plant, net of credits provided by the plant manager. In accordance with the agreements, these advances are returned to the Authority through an annual amount of energy and capacity credits billed by the plant. Annual billings decrease the Advances for capacity and energy balance up to the amount of principal paid on debt by the Authority. Credits in excess of principal paid on debt decrease the Project's current year interest expense. During the current year, the project billed SCPPA $2.1 million, of which approximately $1.2 million was used to decrease the Advances balance. The remaining credits of $0.9 million were utilized to offset debt expense.

Long-term Debt – The Authority acquired its interest in the Hoover Uprating Project through the issuance of revenue bonds. The following graph provides an indication of the principal and interest payments on the Hoover Uprating Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2017-2018. Interest is reflected on an accrual basis.

Hoover Uprating Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on October 1 and April 1 of each year. Principal maturities of $1.2 million were paid on October 1, 2003.

Mead-Phoenix Project
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 41,394	$ 42,786
Investments	8,709	9,751
Cash and cash equivalents	1,768	1,617
Other	5,638	4,957
	$ 57,509	$ 59,111
Liabilities and Net Deficit		
Long-term debt	$ 65,463	$ 64,224
Current liabilities	1,458	2,841
	66,921	67,065
Net assets (deficit):		
Invested in capital assets, net of related debt	(23,013)	(20,672)
Restricted net assets	13,508	13,495
Unrestricted net assets (deficit)	93	(777)
Total net deficit	(9,412)	(7,954)
	$ 57,509	$ 59,111
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 4,679	$ 3,987
Operating expenses	(2,470)	(1,557)
Net operating income	2,209	2,430
Investment income	573	700
Debt expenses	(4,240)	(4,236)
Increase in net deficit	(1,458)	(1,106)
Beginning balance of net deficit	(7,954)	(6,848)
Ending balance of net deficit	$ (9,412)	$ (7,954)

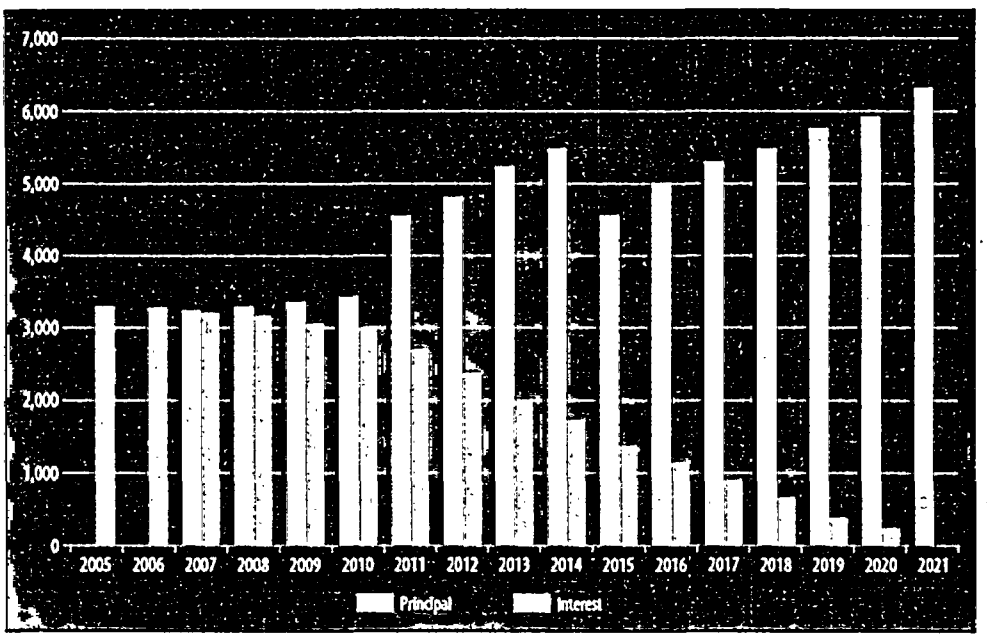
Net Deficit – Net Deficit of the Mead-Phoenix Project increased by $1.5 million mainly due to the scheduled depreciation of utility plant of $1.4 million.

Long-term Debt – The acquisition of the assets of the Mead-Phoenix Project was provided by a transfer of funds from the Multiple Project Fund (See Note 1 of the Notes to Combined Financial Statements). In March 1994, the Authority issued Mead-Phoenix Project Revenue Bonds to advance refund a portion of the Multiple Project Fund Bonds. During the year, the Authority issued new refunding bonds as follows:

Description of Bonds	Par Amount of Refunded Bonds	Par Amount of Refunding Issue	Debt Service Savings	Present Value Savings	Bond Ratings by S&P/Moody's
Mead-Phoenix Project Revenue Bonds 2004 Series A	$ 42,235,000	$ 42,225,000	$ 4,081,649	$ 2,928,381	AAA/Aaa

The following graph provides an indication of the principal and interest payments on the Mead-Phoenix Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2020-2021. Interest is reflected on an accrual basis.

Mead-Phoenix Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Mead-Adelanto Project
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 135,531	$ 140,031
Investments	23,893	27,471
Cash and cash equivalents	3,976	2,791
Other	16,070	14,236
	$ 179,470	$ 184,529
Liabilities and Net Deficit		
Long-term debt	$ 210,861	$ 207,307
Current liabilities	3,522	7,338
	214,383	214,645
Net assets (deficit):		
Invested in capital assets, net of related debt	(71,830)	(64,540)
Restricted net assets	36,073	35,469
Unrestricted net assets (deficit)	844	(1,045)
Total net deficit	(34,913)	(30,116)
	$ 179,470	$ 184,529
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 13,552	$ 11,792
Operating expenses	(6,597)	(4,955)
Net operating income	6,955	6,837
Investment income	1,463	1,860
Debt expenses	(13,215)	(13,432)
Increase in net deficit	(4,797)	(4,735)
Beginning balance of net deficit	(30,116)	(25,381)
Ending balance of net deficit	$ (34,913)	$ (30,116)

Net Deficit – The Net Deficit of the Mead-Adelanto Project increased by $4.8 million mainly due to the scheduled depreciation on utility plant of $4.5 million.

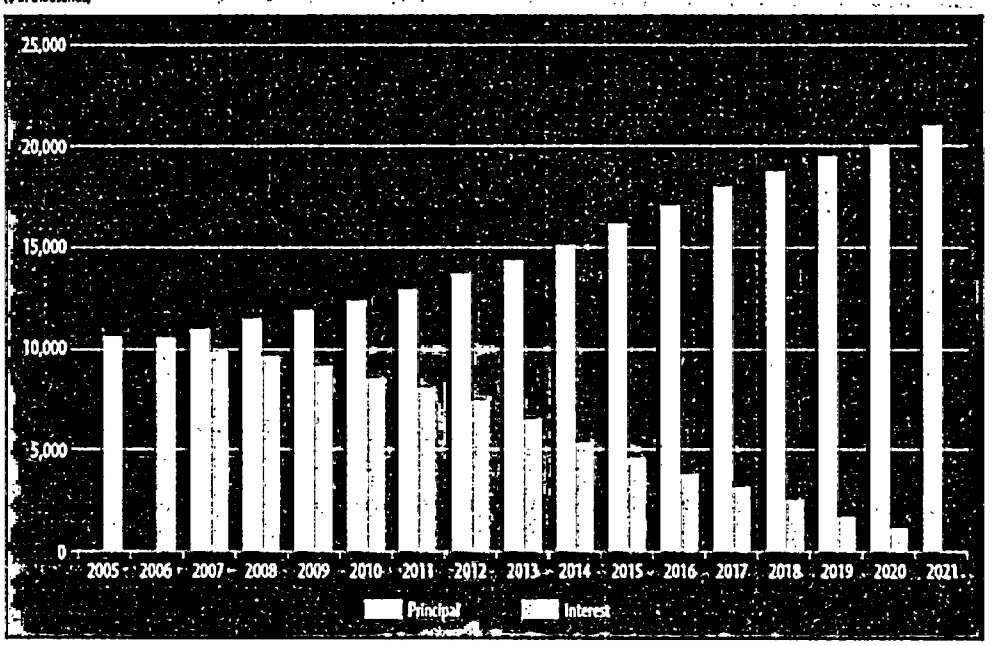
Long-term Debt

Similar to the Mead-Phoenix Project, the interest in the Mead-Adelanto Project was acquired by the Authority through a transfer of funds, and the bonds issued to obtain these funds, from the Multiple Project Fund (See Note 1 of the Notes to Combined Financial Statements). In March 1994, the Authority issued Mead-Adelanto Project Revenue Bonds to advance refund the Multiple Project Fund Bonds. During the year, the Authority issued new refunding bonds as follows:

Description of Bonds	Par Amount of Refunded Bonds	Par Amount of Refunding Issue	Debt Service Savings	Present Value Savings	Bond Ratings by S&P/Moody's
Mead-Adelanto Project Revenue Bonds 2004 Series A	$ 141,155,000	$ 141,150,000	$ 13,645,006	$ 9,798,503	AAA/Aaa

The following graph provides an indication of the principal and interest payments on the Mead-Adelanto Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2020-2021. Interest is reflected on an accrual basis.

Mead-Adelanto Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Multiple Project Fund
Financial Highlights
(In thousands)

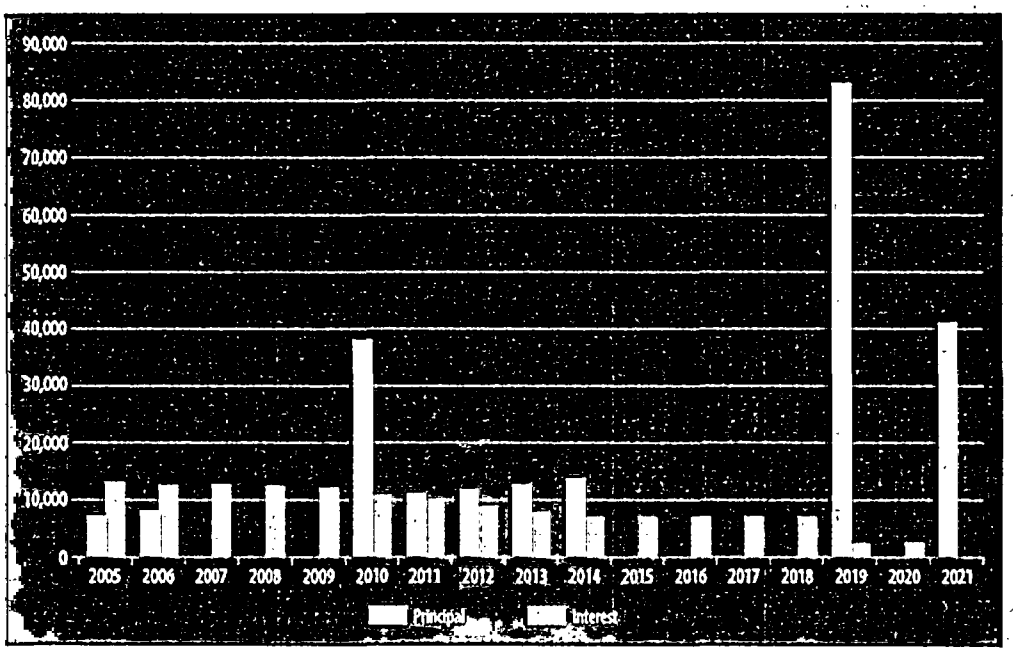
	June 30, 2004	June 30, 2003
Assets		
Investments	$ 238,839	$ 243,437
Cash and cash equivalents	–	–
Other	8,504	8,673
	$ 247,343	$ 252,110
Liabilities and Net Assets		
Long-term debt	$ 209,524	$ 216,445
Current liabilities	30,712	28,973
	240,236	245,418
Net assets:		
Invested in capital assets, net of related debt	–	–
Restricted net assets	7,107	6,692
Unrestricted net assets	–	–
Total net assets	7,107	6,692
	$ 247,343	$ 252,110
Revenues, Expenses and Changes in Net Assets		
Investment income	$ 16,973	$ 17,275
Debt expenses	(16,558)	(16,938)
Increase (decrease) in net assets	415	337
Beginning balance of net assets	6,692	6,355
Ending balance of net assets	$ 7,107	$ 6,692

Net Assets – The increase in Net Assets of $415,000 is due to a $5.2 million decrease in Total Liabilities representing primarily payment of principal maturities during the fiscal year, which is partially offset by a $4.8 million net decrease in investments drawn down to pay for such principal maturities. The increase in net assets represents the difference between investment income earned on bond proceeds deposited in the Multiple Project Fund and the debt expense on such bonds.

Long-term Debt – The Multiple Project Fund was established by the issuance of revenue bonds. The bond proceeds are to be used to finance costs of construction and acquisition of ownership interests or capacity rights in one or more projects that the Authority expects to undertake. Certain of these funds were used to finance the Authority's interest in the Mead-Phoenix and Mead-Adelanto Projects (See Note 1 of the Notes to Combined Financial Statements).

The following graph provides an indication of the principal and interest payments on the Multiple Project Fund that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2020-2021. Interest is reflected on an accrual basis.

Multiple Project Fund
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Par value of bonds that matured and were redeemed on July 1, 2003 was $7.1 million. A total of $50.2 million of the outstanding Multiple Project Revenue Bonds are not subject to redemption prior to maturity.

San Juan Project
Financial Highlights
(In thousands)

	June 30, 2004	June 30, 2003
Assets		
Utility plant, net	$ 70,452	$ 80,989
Investments	26,944	21,602
Cash and cash equivalents	12,671	15,930
Other	10,442	14,859
	$ 120,509	$ 133,380
Liabilities and Net Deficit		
Long-term debt	$ 191,277	$ 200,699
Current liabilities	18,317	16,980
	209,594	217,679
Net assets (deficit):		
Invested in capital assets, net of related debt	(127,557)	(125,669)
Restricted net assets	29,722	27,548
Unrestricted net assets	8,750	13,822
Total net deficit	(89,085)	(84,299)
	$ 120,509	$ 133,380
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 61,735	$ 70,636
Operating expenses	(57,704)	(56,783)
Net operating income (loss)	4,031	13,853
Investment income	1,321	1,289
Debt expenses	(10,138)	(10,771)
Extraordinary loss on debt refunding	–	(74)
Decrease (increase) in net deficit	(4,786)	4,297
Beginning balance of net deficit	(84,299)	(88,596)
Ending balance of net deficit	$ (89,085)	$ (84,299)

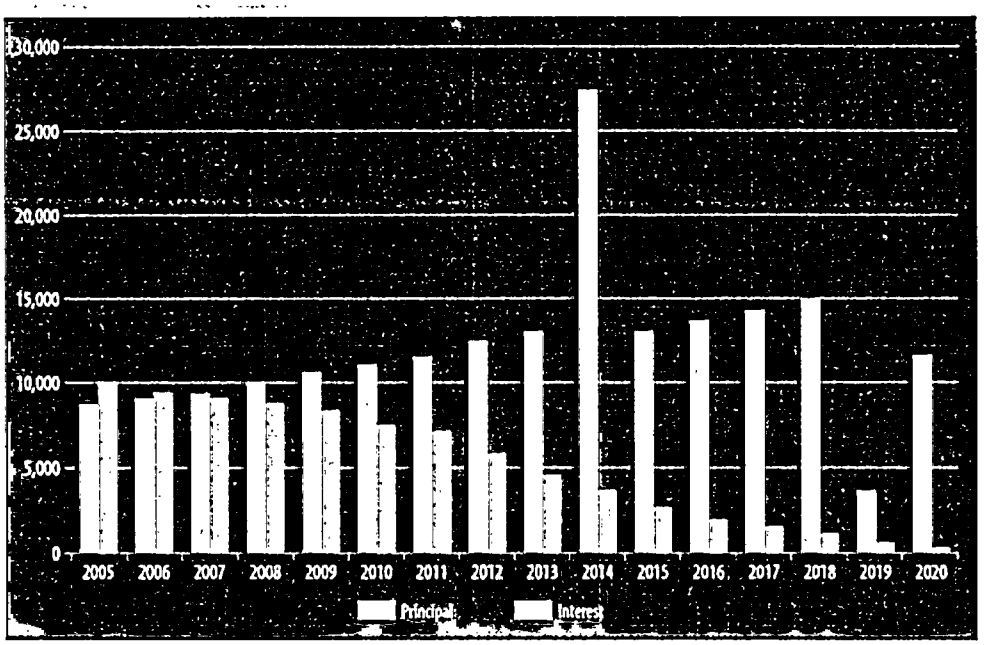
Net Deficit – The Net Deficit of the San Juan Project increased by $4.8 million, primarily due to a decrease of $12.8 million in Total Assets and a decrease in Total Liabilities of $8.1 million. The decrease in Total Assets is largely due to the decrease in utility plant due to $1.9 million plant retirements and the scheduled depreciation allowance of $10.2 million. The decrease in assets was offset mainly by the $8.4 million reduction in long-term debt representing maturity payments during the fiscal year.

Net Operating Income (Loss) – Net Operating Income decreased by $9.8 million when compared to last year. This decrease is primarily due to a decrease in revenues relating to the $9.8 million coal contract buyout from the prior fiscal year. Additionally, there were some offsetting changes in debt service and operational revenue requirements; a $3.2 million decrease in debt service revenue requirement was offset by a similar increase for capital improvements.

Long-term Debt – The Authority financed its acquisition of the assets of the San Juan Project by the issuance of revenue bonds. Currently, capital additions are financed from revenues received from participants. Principal bond maturities that were redeemed on January 1, 2004 totaled $8.4 million.

The following graph provides an indication of the principal and interest payments on the San Juan Project that are due each year following June 30, 2004 until the bonds mature in Fiscal Year 2019-2020. Interest is reflected on an accrual basis.

San Juan Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payment on the bonds are payable semi-annually on July 1 and January 1 of each year.

Magnolia Power Project

Background – In 2000, the City of Burbank (the "City"), an Authority member, initiated a study to determine the requirements for replacing an aging power plant within the city limits. A decision was reached that it would be more economical to build a plant with more capacity than would be required to meet the City's power demands. The City introduced the idea to the Authority and four members, the Cities of Anaheim, Colton, Glendale, and Pasadena (the "Project A Participants"), expressed their interest in joining the City of Burbank in pursuing the Project. The City of Cerritos (the "Project B Participant") also joined in the development of the project when it became a member of the Authority in July 2001.

In March 2003, the California Energy Commission gave its approval for construction of the Magnolia Power Project. The Project is a natural gas-fired generator and is designed to generate 242 megawatts to meet baseload capacity, but will be able to generate more than 300 megawatts for short periods of time during peak demand periods. The plant is the first to be owned by the Authority, and the City of Burbank will manage its construction and operation. To finance the Project, the Authority issued $300 million of Magnolia Power Project A, Revenue Bonds, 2003-1 and $14.1 million of Magnolia Power Project B, Lease Revenue Bonds (City of Cerritos, California) 2003-1 in April 2003 (Refer to Note 5 of the Notes to Combined Financial Statements).

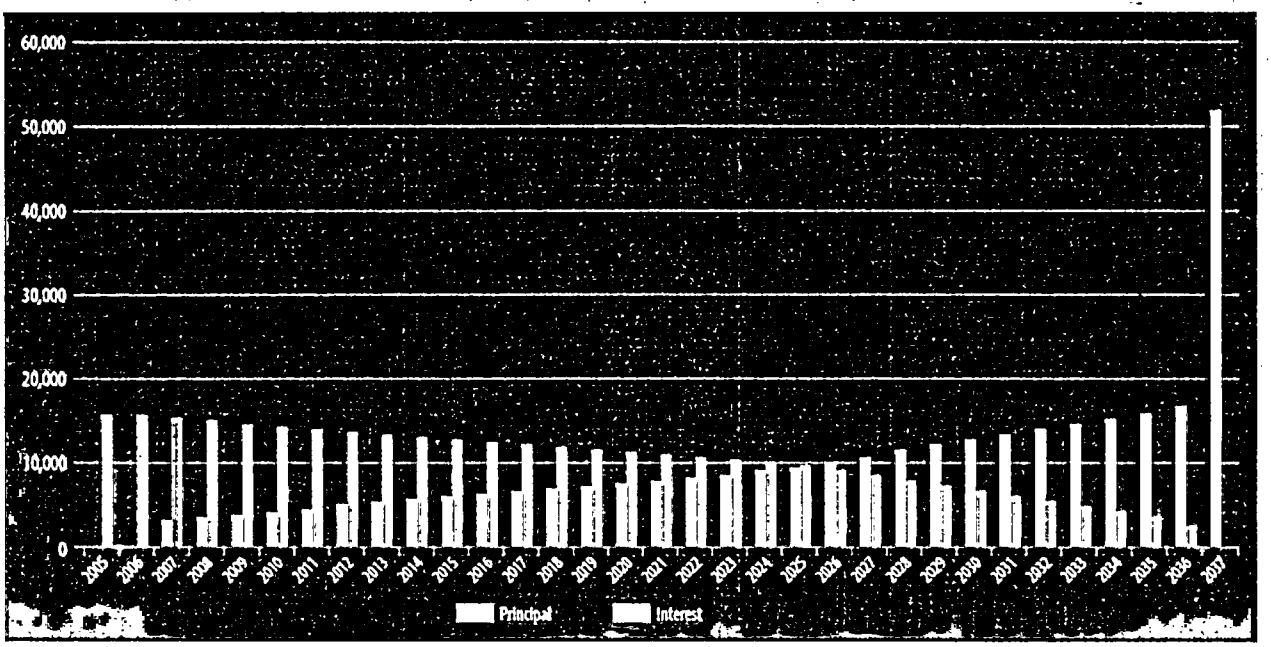
The following table summarizes the financial position of the Project as of June 30, 2004.

	June 30,	
	2004	2003
Assets		
Utility plant, net	$ 203,703	$ 93,610
Investments	128,425	70,426
Cash and cash equivalents	7,883	162,381
Other	6,106	7,234
	$ 346,117	$ 333,651
Liabilities and Net Assets		
Long-term debt	$ 321,327	$ 321,730
Current liabilities	24,790	11,921
	346,117	333,651
Net assets:		
Invested in capital assets, net of related debt	(103,986)	(59,638)
Restricted net assets	103,986	59,638
Unrestricted net assets	–	–
	–	–
Total net assets	$ 346,117	$ 333,651

To date, the Project had no revenues and is not anticipated to have any until the Project becomes operational. During the 2004 fiscal year, additional costs related to the construction of the plant of $97.4 million and debt service costs of $15.1 million offset by investment income of $2.5 million, were capitalized as part of the utility plant balance. Once the plant becomes operational, these costs will be recovered through future billings to participants.

The following graph provides an indication of the principal and interest payments on the Project that are due each year on July 1 until the bonds mature in Fiscal Year 2036-2037. Interest is reflected on an accrual basis.

Magnolia Power Project
Debt Service Requirements
Fiscal Year Ending June 30, 2004
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Projects' Stabilization Fund – In 1996, the Board adopted a resolution to establish the Projects' Stabilization Fund. Monies deposited by the participants to this Fund are used to pay for Authority costs as directed by the Participants (See Note 1 of the Notes to Combined Financial Statements). At June 30, 2004 the Fund had a balance of $51.5 million.

Financial Outlook – The Authority's credit strength is based on:

- The collective credit strengths of each project participant;
- The absence of concentration risk as evidenced by the lack of substantial reliance by one participant on the resources financed;
- The low cost power the Project provides the participants; and,
- Strong legal provisions.

The Authority has take-or-pay power sales and transmission service contracts which unconditionally require the Participants to pay for the cost of operating and maintaining the Projects, including debt service, whether or not the Projects are operating or operable. Although the contracts have not been court-tested, a municipal utility's authority to enter into such contracts is rooted in the State's constitutional provisions for municipal electric utilities.

The Authority continues to play an important role as a legislative advocate and its focused strategic plan continues to provide benefits to member agencies as they prepare for increased competition. The Authority's management continues to focus on lowering the fixed costs of its projects to ensure the flexibility needed to perform in a more competitive marketplace. During the fiscal year, the Authority refunded $183.4 million of the Authority's long-term debt, which generated $17.7 million of debt service savings. In addition, the Authority restructured the Palo Verde 1992 B and C Escrow Funds resulting in a net gain of $572,000, which was deferred and is being amortized over the remaining period of the related bonds. Over the last three years, market opportunities allowed the Authority to save $93.5 million in gross debt service having a present value of $61.0 million by restructuring its debt obligations.

Natural Gas Reserve Acquisition Project

Several SCPPA members, including LADWP, the cities of Anaheim, Burbank, Colton, Glendale, and Pasadena, reached a decision to participate in a project for the potential acquisition of natural gas reserves for their own generating facilities.

SCPPA has also allowed other municipal utilities: Turlock Irrigation District, City of Redding, and the Southern Nevada Water Authority, to participate in the Natural Gas Project. Their participation is limited to project development work only. These three participants will contract directly with each seller as gas properties are identified for acquisition and will not participate in any SCPPA financing.

The SCPPA Board has approved the Natural Gas Project Development Agreement, as well as declared the Natural Gas Acquisition Project as a Study Project. The project participants have signed the Development Agreement, and the LADWP has been appointed the Project Manager responsible for leading the project pursuant to the Agreement. The acquisition program will include several different properties acquired over a period of time. Full participant approval to participate in the entire acquisition program is expected by the end of 2004.

The overall form of financing for the project has been agreed to by the SCPPA participants and will include additional options for the SCPPA members to "bring their own money" or finance through SCPPA. An investment-banking firm was selected to lead the project's financing activities for SCPPA and a natural gas property advisor was hired to advise SCPPA regarding the desirability of potential gas property acquisitions.

Renewable Projects

SCPPA members are committed to the use of renewables in the future.

During the fiscal year, energy from the High Winds Energy Center in Solano County, California, has become a part of the participating members' resource portfolios. SCPPA members including the cities of Anaheim, Azusa, Colton, Glendale, and Pasadena contracted with PPMEnergy (a division of Pacificorp Holdings) for 30 megawatts (MW) of the 150 MW wind facility. PPM also provided a firming service, which guaranteed SCPPA members firm delivery of energy, at predetermined rates, regardless of the wind conditions at the site. Although the purchase contracts under the project were between the individual members and PPM, SCPPA played a key role in bringing this project to a reality through the issuance of the Renewable RFP and coordinating contract negotiations.

SCPPA has entered into a Power Purchase Agreement with Ameresco Chiquita Energy LLC for 100% of the electric generation from a landfill gas to energy facility to be located at the landfill site in Valencia, California (Ameresco Landfill Gas to Energy Project). The SCPPA participants in this project include the cities of Anaheim, Burbank, Glendale, and Pasadena, with their respective shares listed below. This project, which is expected to go on-line in early 2006, will initially be for 13.4 Megawatts with two options to increase the output by an additional 10 Megawatts in the future when additional gas becomes available.

PARTICIPANTS	CONTRACT SHARE
City of Anaheim	33.3333%
City of Burbank	16.6667%
City of Glendale	33.3333%
City of Pasadena	16.6667%

SCPPA continues to look for additional renewable project opportunities on behalf of its members. As projects are identified, expressions of interest from the members will be sought to determine those projects worthy of further consideration and development.

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REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Participants of the
Southern California Public Power Authority:

In our opinion, the accompanying combined statements of net assets (deficit) and the related combined statements of revenues, expenses and changes in net assets (deficit) and cash flows present fairly, in all material respects, the financial position of the Southern California Public Power Authority (the "Authority") at June 30, 2004 and 2003, and the changes in its net assets (deficit) and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the accompanying statements of net assets (deficit) and the related statements of revenues, expenses and changes in net assets (deficit) and cash flows present fairly, in all material respects, the financial position of each of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project, Multiple Project Fund, San Juan Project, Magnolia Power Project, and Projects' Stabilization Fund at June 30, 2004 and 2003, and the changes in their net assets (deficit) and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective July 1, 2002, the Authority changed its election under Governmental Accounting Standards Board Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, and no longer applies Financial Accounting Standards Board statements and interpretations issued after November 30, 1989.

The management's discussion and analysis included on pages 20-39 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we did not audit the information and express no opinion on it.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial information, as listed in the accompanying index, is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

PricewaterhouseCoopers LLP

September 16, 2004

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2004
(Amounts in thousands)

	June 30, 2004											
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total	Eliminations	Total Combined
ASSETS												
Noncurrent Assets												
Utility plant:												
Production	$ 634,940	$ –	$ –	$ –	$ –	$ –	$ 171,781	$ –	$ –	$ 806,721	$ –	$ 806,721
Transmission	14,062	674,606	–	50,770	172,319	–	–	–	–	911,757	–	911,757
General	2,699	18,911	21	2,640	473	–	7,425	–	–	32,169	–	32,169
	651,701	693,517	21	53,410	172,792	–	179,206	–	–	1,750,647	–	1,750,647
Less - Accumulated depreciation	511,017	351,361	21	12,028	37,261	–	111,282	–	–	1,022,970	–	1,022,970
	140,684	342,156	–	41,382	135,531	–	67,924	–	–	727,677	–	727,677
Construction work in progress	9,950	–	–	12	–	–	2,528	203,703	–	216,193	–	216,193
Nuclear fuel, at amortized cost	14,309	–	–	–	–	–	–	–	–	14,309	–	14,309
Net utility plant	164,943	342,156	–	41,394	135,531	–	70,452	203,703	–	958,179	–	958,179
Special funds:												
Restricted investments												
Escrow accounts	481,730	10,354	–	–	–	–	–	–	–	492,084	–	492,084
Decommissioning fund	126,943	–	–	–	–	–	–	–	–	126,943	–	126,943
Other funds	53,524	46,007	2,358	8,709	23,893	238,839	26,944	128,425	49,935	578,634	–	578,634
	662,197	56,361	2,358	8,709	23,893	238,839	26,944	128,425	49,935	1,197,661	–	1,197,661
Unrestricted Investments												
Other funds	20,502	–	560	–	–	–	–	–	–	21,062	–	21,062
Total special funds	682,699	56,361	2,918	8,709	23,893	238,839	26,944	128,425	49,935	1,218,723	–	1,218,723
Other Noncurrent Assets												
Advance to IPA - restricted	–	11,550	–	–	–	–	–	–	–	11,550	–	11,550
Advances for capacity and energy, net - restricted	–	–	18,974	–	–	–	–	–	–	18,974	–	18,974
Unamortized debt expenses	4,854	8,136	399	1,055	3,500	–	2,330	5,755	–	26,029	–	26,029
Total other noncurrent assets	4,854	19,686	19,373	1,055	3,500	–	2,330	5,755	–	56,553	–	56,553
Total noncurrent assets	852,496	418,203	22,291	51,158	162,924	238,839	99,726	337,883	49,935	2,233,455	–	2,233,455
Current Assets												
Special funds:												
Cash and cash equivalents - restricted	155,285	38,048	410	1,247	2,680	–	7,826	7,883	955	214,334	–	214,334
Cash and cash equivalents - unrestricted	5,170	2,986	831	521	1,296	–	4,845	–	–	15,649	–	15,649
Interest receivable	1,387	26	27	339	900	8,504	48	351	565	12,147	–	12,147
Accounts receivable	929	3,807	–	–	–	–	4,798	–	–	9,534	–	9,534
Due from other project - restricted	–	–	–	4,244	11,670	–	–	–	–	15,914	–	–
Materials and supplies	6,785	–	–	–	–	–	3,266	–	–	10,051	–	10,051
Total current assets	169,556	44,867	1,268	6,351	16,546	8,504	20,783	8,234	1,520	277,629	–	261,715
Total assets	1,022,052	463,070	23,559	57,509	179,470	247,343	120,509	346,117	51,455	2,511,084	(15,914)	2,495,170
LIABILITIES												
Noncurrent liabilities												
Long-term debt	569,050	795,222	18,575	65,463	210,861	209,524	191,277	321,327	–	2,381,299	–	2,381,299
Commitments and contingencies (Note 7)	–	–	–	–	–	–	–	–	–	–	–	–
Total noncurrent liabilities	569,050	795,222	18,575	65,463	210,861	209,524	191,277	321,327	–	2,381,299	–	2,381,299
Current liabilities:												
Debt due within one year	51,800	28,535	1,230	–	–	7,600	8,805	–	–	97,970	–	97,970
Accrued interest	5,933	6,525	255	1,030	3,070	7,198	5,095	7,585	–	36,691	–	36,691
Accounts payable and accruals	65,776	14,464	52	428	452	–	4,052	17,205	–	102,429	–	102,429
Accrued property tax	1,548	–	–	–	–	–	365	–	–	1,913	–	1,913
Coal contracts buyout	–	–	–	–	–	–	–	–	–	–	–	–
Due to other projects	–	–	–	–	–	15,914	–	–	–	15,914	–	–
Total current liabilities	125,057	49,524	1,537	1,458	3,522	30,712	18,317	24,790	–	254,917	–	239,033
Total liabilities	694,107	844,746	20,112	66,921	214,383	240,236	209,594	346,117	–	2,636,216	(15,914)	2,620,302
NET ASSETS (DEFICIT)												
Invested in capital assets, net of related debt and deferred credits	(451,167)	(473,464)	–	(23,013)	(71,830)	–	(127,557)	(103,986)	–	(1,251,017)	–	(1,251,017)
Restricted net assets	757,558	99,459	2,104	13,508	36,073	7,107	29,722	103,986	51,455	1,100,972	–	1,100,972
Unrestricted net assets (deficit)	21,554	(7,671)	1,343	93	844	–	8,750	–	–	24,913	–	24,913
Total net assets (deficit)	$ 327,945	$ (381,676)	$ 3,447	$ (9,412)	$ (34,913)	$ 7,107	$ (89,085)	$ –	$ 51,455	$ (125,132)	–	$ (125,132)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2003
(Amounts in thousands)

	June 30, 2003											
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total	Eliminations	Total Combined
ASSETS												
Noncurrent Assets												
Utility plant:												
Production	$ 623,352	$ –	$ –	$ –	$ –	$ –	$ 172,475	$ –	$ –	$ 795,827	$ –	$ 795,827
Transmission	14,062	674,606	–	50,770	172,319	–	–	–	–	911,757	–	911,757
General	2,705	18,911	22	2,640	473	–	8,067	–	–	32,818	–	32,818
	640,119	693,517	22	53,410	172,792	–	180,542	–	–	1,740,402	–	1,740,402
Less - Accumulated depreciation	489,707	331,732	22	10,624	32,761	–	99,826	–	–	964,672	–	964,672
	150,412	361,785	–	42,786	140,031	–	80,716	–	–	775,730	–	775,730
Construction work in progress	18,862	–	–	–	–	–	273	93,610	–	112,745	–	112,745
Nuclear fuel, at amortized cost	14,544	–	–	–	–	–	–	–	–	14,544	–	14,544
Net utility plant	183,818	361,785	–	42,786	140,031	–	80,989	93,610	–	903,019	–	903,019
Special funds:												
Restricted investments												
Escrow accounts	420,766	16,883	–	–	–	–	–	–	–	437,649	–	437,649
Decommissioning fund	116,936	–	–	–	–	–	–	–	–	116,936	–	116,936
Other funds	124,227	41,919	–	9,751	27,471	243,437	21,602	70,426	53,044	591,877	–	591,877
	661,929	58,802	–	9,751	27,471	243,437	21,602	70,426	53,044	1,146,462	–	1,146,462
Unrestricted Investments												
Other funds	12,995	–	500	–	–	–	–	–	–	13,495	–	13,495
Total special funds	674,924	58,802	500	9,751	27,471	243,437	21,602	70,426	53,044	1,159,957	–	1,159,957
Other Noncurrent Assets												
Advance to IPA - restricted	–	11,550	–	–	–	–	–	–	–	11,550	–	11,550
Advances for capacity and energy, net - restricted	–	–	20,197	–	–	–	–	–	–	20,197	–	20,197
Unamortized debt expenses	5,382	8,945	476	766	2,736	–	2,590	6,100	–	26,995	–	26,995
Total other noncurrent assets	5,382	20,495	20,673	766	2,736	–	2,590	6,100	–	58,742	–	58,742
Total noncurrent assets	864,124	441,082	21,173	53,303	170,238	243,437	105,181	170,136	53,044	2,121,718	–	2,121,718
Current Assets												
Special funds:												
Cash and cash equivalents - restricted	96,075	37,372	2,884	1,498	2,616	–	11,236	162,381	42,941	357,003	–	357,003
Cash and cash equivalents - unrestricted	9,067	564	842	119	175	–	4,694	–	–	15,461	–	15,461
Interest receivable	1,405	137	1	343	915	8,673	13	1,061	436	12,984	–	12,984
Accounts receivable	1,043	2,369	–	–	3	–	9,021	73	–	12,509	–	12,509
Due from other project - restricted	–	–	–	3,848	10,582	–	–	–	–	14,430	–	–
Materials and supplies	6,828	–	–	–	–	–	3,235	–	–	10,063	–	10,063
Total current assets	114,418	40,442	3,727	5,808	14,291	8,673	28,199	163,515	43,377	422,450	–	408,020
Total assets	978,542	481,524	24,900	59,111	184,529	252,110	133,380	333,651	96,421	2,544,168	(14,430)	2,529,738
LIABILITIES												
Noncurrent liabilities												
Long-term debt	609,150	807,669	19,404	64,224	207,307	216,445	200,699	321,730	–	2,446,628	–	2,446,628
Commitments and contingencies (Note 7)	–	–	–	–	–	–	–	–	–	–	–	–
Total noncurrent liabilities	609,150	807,669	19,404	64,224	207,307	216,445	200,699	321,730	–	2,446,628	–	2,446,628
Current liabilities:												
Debt due within one year	49,190	29,720	1,190	–	–	7,100	8,390	–	–	95,590	–	95,590
Accrued interest	7,197	6,922	265	1,945	6,116	7,443	5,303	4,467	–	39,658	–	39,658
Accounts payable and accruals	56,095	3,587	188	896	1,222	–	2,887	7,454	–	72,329	–	72,329
Accrued property tax	1,548	–	–	–	–	–	400	–	–	1,948	–	1,948
Coal contracts buyout	–	–	–	–	–	–	–	–	–	–	–	–
Due to other projects	–	–	–	–	–	14,430	–	–	–	14,430	–	–
Total current liabilities	114,030	40,229	1,643	2,841	7,338	28,973	16,980	11,921	–	223,955	–	209,525
Total liabilities	723,180	847,898	21,047	67,065	214,645	245,418	217,679	333,651	–	2,670,583	(14,430)	2,656,153
NET ASSETS (DEFICIT)												
Invested in capital assets, net of related debt and deferred credits	(469,233)	(466,659)	–	(20,672)	(64,540)	–	(125,669)	(59,638)	–	(1,206,411)	–	(1,206,411)
Restricted net assets	706,613	100,939	2,699	13,495	35,469	6,692	27,548	59,638	96,421	1,049,514	–	1,049,514
Unrestricted net assets (deficit)	17,982	(654)	1,154	(777)	(1,045)	–	13,822	–	–	30,482	–	30,482
Total net assets (deficit)	$ 255,362	$ (366,374)	$ 3,853	$ (7,954)	$ (30,116)	$ 6,692	$ (84,299)	$ –	$ 96,421	$ (126,415)	–	$ (126,415)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Year Ended June 30, 2004									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Operating revenues:										
Sales of electric energy	$ 164,884	$ –	$ 2,554	$ –	$ –	$ –	$ 61,735	$ –	$ –	$ 229,173
Sales of transmission services	–	72,618	–	4,679	13,552	–	–	–	–	90,849
Total operating revenues	164,884	72,618	2,554	4,679	13,552	–	61,735	–	–	320,022
Operating expenses:										
Operations and maintenance	26,767	13,743	2,331	1,066	2,097	–	44,382	–	–	90,386
Depreciation	17,946	19,628	–	1,404	4,500	–	10,209	–	–	53,687
Amortization of nuclear fuel	7,883	–	–	–	–	–	–	–	–	7,883
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Total operating expenses	63,496	33,371	2,331	2,470	6,597	–	57,704	–	–	165,969
Operating income (loss)	101,388	39,247	223	2,209	6,955	–	4,031	–	–	154,053
Non operating revenues (expenses)										
Investment income	14,144	3,044	18	700	1,844	16,973	1,321	–	379	38,423
Debt expense	(42,949)	(57,593)	(647)	(4,240)	(13,215)	(16,558)	(10,138)	–	–	(145,340)
Net non operating revenues (expenses)	(28,805)	(54,549)	(629)	(3,540)	(11,371)	415	(8,817)	–	379	(106,917)
Increase (decrease) in net assets (deficit) before extraordinary items	72,583	(15,302)	(406)	(1,331)	(4,416)	415	(4,786)	–	379	47,136
Extraordinary loss on refunding of debt	–	–	–	(127)	(381)	–	–	–	–	(508)
Net increase (decrease) in net assets (deficit)	72,583	(15,302)	(406)	(1,458)	(4,797)	415	(4,786)	–	379	46,628
Net assets (deficit) - beginning of year	255,362	(366,374)	3,853	(7,954)	(30,116)	6,692	(84,299)	–	96,421	(126,415)
Net withdrawals by participants	–	–	–	–	–	–	–	–	(45,345)	(45,345)
Net assets (deficit) - end of year	$ 327,945	$ (381,676)	$ 3,447	$ (9,412)	$ (34,913)	$ 7,107	$ (89,085)	$ –	$ 51,455	$ (125,132)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Year Ended June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Operating revenues:										
Sales of electric energy	$ 180,529	$ –	$ 2,330	$ –	$ –	$ –	$ 70,636	$ –	$ –	$ 253,495
Sales of transmission services	–	82,229	–	3,987	11,792	–	–	–	–	98,008
Total operating revenues	180,529	82,229	2,330	3,987	11,792	–	70,636	–	–	351,503
Operating expenses:										
Operations and maintenance	27,462	13,804	2,377	152	454	–	43,586	–	–	87,835
Depreciation	26,702	19,629	4	1,405	4,501	–	10,084	–	–	62,325
Amortization of nuclear fuel	8,586	–	–	–	–	–	–	–	–	8,586
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Total operating expenses	73,650	33,433	2,381	1,557	4,955	–	56,783	–	–	172,759
Operating income (loss)	106,879	48,796	(51)	2,430	6,837	–	13,853	–	–	178,744
Non operating revenues (expenses)										
Investment income	96,885	6,131	73	700	1,860	17,275	1,289	–	2,372	126,585
Debt expense	(47,941)	(62,592)	(331)	(4,236)	(13,432)	(16,938)	(10,771)	–	–	(156,241)
Net non operating revenues (expenses)	48,944	(56,461)	(258)	(3,536)	(11,572)	337	(9,482)	–	2,372	(29,656)
Increase (decrease) in net assets (deficit) before extraordinary items	155,823	(7,665)	(309)	(1,106)	(4,735)	337	4,371	–	2,372	149,088
Extraordinary loss on refunding of debt	–	(2,484)	–	–	–	–	(74)	–	–	(2,558)
Net increase (decrease) in net assets (deficit)	155,823	(10,149)	(309)	(1,106)	(4,735)	337	4,297	–	2,372	146,530
Net assets (deficit) - beginning of year as restated (note 2)	99,539	(356,225)	4,162	(6,848)	(25,381)	6,355	(88,596)	–	173,785	(193,209)
Net withdrawals by participants	–	–	–	–	–	–	–	–	(79,736)	(79,736)
Net assets (deficit) - end of year	$ 255,362	$ (366,374)	$ 3,853	$ (7,954)	$ (30,116)	$ 6,692	$ (84,299)	$ –	$ 96,421	$ (126,415)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Year Ended June 30, 2004									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:										
Receipts from participants	$ 174,793	$ 87,653	$ 2,428	$ 4,515	$ 13,747	$ –	$ 65,055	$ –	$ –	$ 348,191
Payments to operating managers	(28,055)	(18,976)	(254)	(1,275)	(2,320)	–	(43,104)	–	–	(93,984)
Other receipts	153	–	–	159	–	–	–	–	–	312
Net cash flow from operating activities	146,891	68,677	2,174	3,399	11,427	–	21,951	–	–	254,519
Cash flows from noncapital financing activities:										
Withdrawals by participants, net	–	–	–	–	–	–	–	16	(45,345)	(45,329)
Cash flows from capital and related financing activities:										
Additions to plant, net	(16,681)	–	–	(12)	–	–	(2,154)	(87,669)	–	(106,516)
Debt interest payments	(32,649)	(41,230)	(1,041)	(4,351)	(13,570)	(14,641)	(10,606)	(12,052)	–	(130,140)
Proceeds from sale of bonds	–	–	–	44,004	147,064	–	–	–	–	191,068
Proceeds from escrow restructuring	628	–	–	–	–	–	–	–	–	628
Payment for escrow restructuring costs	(56)	–	–	–	–	–	–	–	–	(56)
Payment for defeasance of revenue bonds	–	–	–	(44,061)	(147,259)	–	–	–	–	(191,320)
Principal payments on debt	(49,190)	(29,720)	(1,190)	–	–	(7,100)	(8,390)	–	–	(95,590)
Transfer of funds from escrow	–	6,545	–	–	–	–	–	–	–	6,545
Payment for bond issue costs	–	(220)	–	(572)	(1,913)	–	–	(12)	–	(2,717)
Net cash provided by (used for) capital and related financing activities	(97,948)	(64,625)	(2,231)	(4,992)	(15,678)	(21,741)	(21,150)	(99,733)	–	(328,098)
Cash flows from investing activities:										
Interest received on investments	7,469	2,949	49	701	1,853	17,142	1,284	4,076	1,594	37,117
Purchases of investments	(360,555)	(42,473)	(2,977)	(784)	(1,877)	(1,271)	(13,264)	(105,005)	(62,942)	(591,148)
Proceeds from sale/maturity of investments	359,456	38,570	500	1,827	5,460	5,870	7,920	46,148	64,707	530,458
Net cash provided by (used for) investing activities	6,370	(954)	(2,428)	1,744	5,436	21,741	(4,060)	(54,781)	3,359	(23,573)
Net increase (decrease) in cash and cash equivalents	55,313	3,098	(2,485)	151	1,185	–	(3,259)	(154,498)	(41,986)	(142,481)
Cash and cash equivalents at beginning of year	105,142	37,936	3,726	1,617	2,791	–	15,930	162,381	42,941	372,464
Cash and cash equivalents at end of year	$ 160,455	$ 41,034	$ 1,241	$ 1,768	$ 3,976	$ –	$ 12,671	$ 7,883	$ 955	$ 229,983
Reconciliation of operating income to net cash provided by operating activities:										
Operating income	$ 101,388	$ 39,247	$ 223	$ 2,209	$ 6,955	$ –	$ 4,031	$ –	$ –	$ 154,053
Adjustments to reconcile operating income to net cash provided (used) by operating activities:										
Depreciation	17,946	19,628	–	1,404	4,500	–	10,209	–	–	53,687
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Advances for capacity and energy	–	–	2,085	–	–	–	–	–	–	2,085
Amortization of nuclear fuel	7,883	–	–	–	–	–	–	–	–	7,883
Changes in assets and liabilities:										
Accounts receivable	174	(1,438)	–	–	3	–	4,223	–	–	2,962
Accounts payable and accruals	8,577	11,240	(134)	(214)	(31)	–	503	–	–	19,941
Other	23	–	–	–	–	–	(128)	–	–	(105)
Net cash provided by operating activities	$ 146,891	$ 68,677	$ 2,174	$ 3,399	$ 11,427	$ –	$ 21,951	$ –	$ –	$ 254,519

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Year Ended June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:										
Receipts from participants	$ 191,357	$ 72,665	$ 2,289	$ 4,179	$ 11,407	$ –	$ 61,123	$ –	$ –	$ 343,020
Payments to operating managers	(29,317)	(13,475)	(261)	(1,009)	(1,125)	–	(53,811)	–	–	(98,998)
Other receipts	166	3	3	100	4	–	–	–	–	276
Net cash flow from operating activities	162,206	59,193	2,031	3,270	10,286	–	7,312	–	–	244,298
Cash flows from noncapital financing activities:										
Withdrawals by participants, net	–	–	–	–	–	–	–	–	(79,736)	(79,736)
Cash flows from capital and related financing activities:										
Additions to plant, net	(15,996)	–	–	–	–	–	(290)	(84,119)	–	(100,405)
Debt interest payments	(35,192)	(42,149)	(1,077)	(3,889)	(12,232)	(15,111)	(7,485)	–	–	(117,135)
Proceeds from sale of bonds	–	93,658	–	–	–	–	80,750	322,582	–	496,990
Proceeds from bond escrow restructuring	17,292	–	–	–	–	–	–	–	–	17,292
Payment for defeasance of revenue bonds	–	(108,945)	–	–	–	–	(72,344)	–	–	(181,289)
Principal payments on debt	(47,395)	(26,695)	(905)	–	–	(6,600)	(1,600)	–	–	(83,195)
Transfer of funds from escrow	–	–	–	–	–	–	–	–	–	–
Payment for bond issue costs	(580)	(1,605)	–	–	–	–	(1,218)	(6,270)	–	(9,673)
Net cash provided by (used for) capital and related financing activities	(81,871)	(85,736)	(1,982)	(3,889)	(12,232)	(21,711)	(2,187)	232,193	–	22,585
Cash flows from investing activities:										
Interest received on investments	9,017	4,217	77	689	1,832	17,564	1,270	199	2,421	37,286
Purchases of investments	(550,977)	(47,544)	(4,122)	(609)	(4,894)	(1,188)	(15,553)	(75,783)	(92,323)	(792,993)
Proceeds from sale/maturity of investments	506,618	74,274	7,595	75	3,905	5,334	10,025	5,772	197,609	811,207
Net cash provided by (used for) investing activities	(35,342)	30,947	3,550	155	843	21,710	(4,258)	(69,812)	107,707	55,500
Net increase (decrease) in cash and cash equivalents	44,993	4,404	3,599	(464)	(1,103)	(1)	867	162,381	27,971	242,647
Cash and cash equivalents at beginning of year	60,149	33,532	127	2,081	3,894	1	15,063	–	14,970	129,817
Cash and cash equivalents at end of year	$ 105,142	$ 37,936	$ 3,726	$ 1,617	$ 2,791	$ –	$ 15,930	$ 162,381	$ 42,941	$ 372,464
Reconciliation of operating income to net cash provided by operating activities:										
Operating income (loss)	$ 106,879	$ 48,796	$ (51)	$ 2,430	$ 6,838	$ –	$ 13,853	$ –	$ –	$ 178,745
Adjustments to reconcile operating income to net cash provided (used) by operating activities:										
Depreciation	26,702	19,629	4	1,405	4,501	–	10,084	–	–	62,325
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Advances for capacity and energy	–	–	2,124	–	–	–	–	–	–	2,124
Amortization of nuclear fuel	8,586	–	–	–	–	–	–	–	–	8,586
Changes in assets and liabilities:										
Accounts receivable	201	(2,369)	–	–	(3)	–	(8,812)	–	–	(10,983)
Accounts payable and accruals	8,888	(5,829)	(56)	(565)	(1,058)	–	(10,855)	–	–	(9,475)
Other	50	(1,034)	10	–	8	–	(71)	–	–	(1,037)
Net cash provided by operating activities	$ 162,206	$ 59,193	$ 2,031	$ 3,270	$ 10,286	$ –	$ 7,312	$ –	$ –	$ 244,298

The accompanying notes are an integral part of the combined financial statements.

1. Organization and Purpose

The Southern California Public Power Authority (the "Authority"), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participants consist of eleven Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

The Authority has interests in the following projects:

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, a 5.56% ownership interest in the Arizona Nuclear Power Project High Voltage Switchyard, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA"), to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS"), which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

Mead-Phoenix and Mead-Adelanto Projects – As of August 4, 1992, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project ("Mead-Phoenix"), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component.

As of August 4, 1992, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project ("Mead-Adelanto"), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund and commercial operations commenced in April 1996. LADWP serves as the operations manager of Mead-Adelanto

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3 and related common facilities, of the San Juan Generating Station ("SJGS") from Century Power Corporation. Unit 3, a 497-megawatt unit, is one unit of a four-unit coal-fired power generating station in New Mexico.

Magnolia Power Project (the "Project") – In March 2003, the Authority received approval from the California Energy Commission for construction of the Magnolia Power Project. The Project will consist of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts and is currently being built on a site in the City of Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members. The City of Burbank, a Project participant, is managing its construction and operation. Construction is under way and commercial operation is expected to begin in mid-2005. During the current year, the Project had no revenues and is not anticipated to have any until the Project becomes operational. Costs related to the construction of the plant of $97.5 million and debt service costs of $15.1 million offset by investment income of $2.5 million, were capitalized as part of the utility plant balance. Once the plant becomes operational, these costs will be recovered through future billings to participants.

Projects' Stabilization Fund – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits within SCPPA project purposes. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust.

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

Participant Ownership Interests – The Authority's participants may elect to participate in the projects. As of June 30, 2004, the members have the following participation percentages in the Authority's interest in the projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power
City of Los Angeles	67.0%	59.5%		24.8%	35.7%		
City of Anaheim		17.6%	42.6%	24.2%	13.5%		38.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%		
Imperial Irrigation District	6.5%					51.0%	
City of Vernon	4.9%						
City of Azusa	1.0%		4.2%	1.0%	2.2%	14.7%	
City of Banning	1.0%		2.1%	1.0%	1.3%	9.8%	
City of Colton	1.0%		3.2%	1.0%	2.6%	14.7%	4.2%
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%		31.0%
City of Glendale	4.4%	2.3%		14.8%	11.1%	9.8%	16.5%
City of Cerritos							4.2%
City of Pasadena	4.4%	5.9%		13.8%	8.6%		6.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100%

The Authority has entered into power sales and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output or transmission service, as applicable. The participants are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner that will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding.

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036

The Authority's interests in generation and transmission projects are jointly owned with other utilities, except for the Magnolia Project, which is wholly owned by the Authority. Under these arrangements, a participating member has an undivided interest in a utility plant and is responsible for its proportionate share of the costs of construction and operation and it is entitled to its proportionate share of the energy produced. Each joint plant participant, including the Authority, is responsible for financing its share of construction and operating costs. The financial statements reflect the Authority's interest in each jointly owned project as well as the project that it owns. Additionally, the Authority's share of expenses for each project is included in the statements of revenues, expenses, and changes in net assets (deficit) as part of operations and maintenances expenses.

2. Summary of Significant Accounting Policies

The accounting records of the Authority are maintained in accordance with accounting principles generally accepted in the United States of America. In prior years, the Authority, as a government-owned utility, applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which were not in conflict with statements issued by the GASB. Effective July 1, 2002, the Authority changed its election under the guidance in GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, to follow all GASB statements and only FASB statements and interpretations issued before November 30, 1989.

Accounting Changes

Change in Election of Application of GASB 20 – Effective July 1, 2002, the Authority changed its election under the guidance in GASB 20 and no longer follows FASB statements issued after November 30, 1989. The impact on the Authority's financial statements as a result of this change was the discontinuation of the application of FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FASB 133). The Authority adopted FASB 133 in fiscal year 2001 and consequently began reporting its derivative instruments at fair value. With this accounting change, the Authority is no longer required to report its derivative instruments at fair value under the guidance applicable to state and local governments. The Authority believes that this was a change to a preferable method of accounting.

Adoption of GASB Statements Nos. 34, 37, and 38 – On July 1, 2001, the Authority adopted GASB Statement No. 34 (GASB 34), *"Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments"*; GASB Statement No. 37 (GASB 37), *"Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments: Omnibus – an Amendment of GASB Statements No. 21 and No. 34"* and GASB Statement No. 38 *"Certain Financial Statement Note Disclosures"* (GASB 38). GASB 34, as amended, and GASB 38 establish specific standards for external financial reporting for all state and local governments. As a result of adopting these Standards, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing and financing activities. GASB 34 also requires the classification of net assets (deficit) into three components – invested in capital assets, net of related debt; restricted; and unrestricted. These classifications are defined as follows:

- **Invested in capital assets, net of related debt** – This component of net assets consists of (a) capital assets, (b) net of accumulated depreciation and (c) unamortized debt expenses, reduced by the outstanding balances of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of those assets. If there are significant unspent related debt proceeds at year-end, the portion of the debt attributable to the unspent proceeds is not included in the calculation of Invested in capital assets, net of related debt. Rather, that portion of the debt is included in the same net assets component as the unspent proceeds.

- **Restricted** – This component consists of net assets on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

- **Unrestricted net assets** – This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt."

Under GASB 34, the statements of equity and of other comprehensive income were eliminated; the statement of income was renamed the statement of revenues, expenses and changes in net assets (deficit); and the statement of cash flows presentation was changed to the direct method (including a reconciliation of operating cash flows to operating income). The adoption of GASB 34 had no significant effect

on the basic combined financial statements, except for the change from the indirect method to the direct method of reporting cash flows and the reclassification of cost recoverable, deferred credits and funds due to participants to net assets (deficit) in accordance with the Statement.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant – The Authority's share of construction and betterment costs associated with PVNGS, STS, Mead-Phoenix, Mead-Adelanto, SJGS and Magnolia Power Projects are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years for PVNGS, STS, Mead-Phoenix and Mead-Adelanto and twenty-one years for SJGS.

Nuclear Fuel – Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each entity with nuclear operations, including the participants in PVNGS, $1 per megawatt hour of nuclear generation. The Authority records this charge as a current year expense. See Note 7 for information about spent nuclear fuel disposal.

Nuclear Decommissioning – Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Authority's interest in PVNGS is estimated to be $116.6 million in 2002 dollars ($375.0 million in 2022 dollars, assuming a 6% estimated annual inflation rate). This estimate is based on an updated site specific study prepared by an independent consultant in 2001. The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant through annual charges to expense, which amounted to $10.9 million in fiscal years 2004 and 2003. The decommissioning liability is included as a component of accumulated depreciation and was $181.6 and $170.8 million at June 30, 2004 and 2003, respectively.

A summary of changes in Utility plant follows (amounts in thousands):

	Balance June 30, 2003	Additions	Disposals	Transfers	Balance June 30, 2004
Nondepreciable Utility Plant					
Land	$ 36,187	$ –	$ –	$ 6,264	$ 42,451
Construction work in progress	112,745	123,101	–	(19,653)	216,193
Nuclear fuel*	14,544	5,561	(5,796)	–	14,309
Total nondepreciable utility plant	163,476	128,662	(5,796)	(13,389)	272,953
Depreciable Utility Plant					
Production					
Nuclear generation (Palo Verde Project)	622,636	19,100	(7,512)	–	634,224
Coal-fired plant (San Juan Unit 3 Project)	172,475	529	(1,223)	–	171,781
Transmission	876,286	–	–	(6,264)	870,022
General	32,818	24	(673)	–	32,169
Total depreciable utility plant	1,704,215	19,653	(9,408)	(6,264)	1,708,196
Less accumulated depreciation	(964,672)	(67,700)	9,402	–	(1,022,970)
Total utility plant, net	$ 903,019	$ 80,615	$ (5,802)	$ (19,653)	$ 958,179

*Nuclear fuel disposals represent amortization.

The Authority contributes to external trusts set up in accordance with the Arizona Nuclear Power Plant participation agreement and Nuclear Regulatory Commission requirements. As of June 30, 2004, decommissioning funds totaled approximately $128.1 million, including approximately $1.16 million of interest receivable.

Demolition and Site Reclamation – Demolition and site reclamation of SJGS, which involves restoring the site to a "green" condition, is projected to commence subsequent to the year 2014. Based upon the study performed by an independent engineering firm, the Authority's share of the estimated demolition and site reclamation costs is $30.8 million in 2003 dollars. The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant through annual charges to expense of $3.1 million. The demolition liability is included as a component of accumulated depreciation and totaled $34.2 million and $31.1 million at June 30, 2004 and 2003, respectively.

As of June 30, 2004, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

Investments – Investments include United States government and governmental agency securities, guaranteed investment contracts, medium term notes and money market accounts. These investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenues, expenses and changes in net assets (deficit) with the exception of the guaranteed investment contracts which are recorded at amortized cost. Gains and losses realized on the sale of investments are generally determined using the specific identification method.

The Bond Indentures for the seven Projects and the Multiple Project Fund require the use of trust funds to account for the Authority's receipts and disbursements. Cash and investments held in these funds are restricted to specific purposes as stipulated in the Bond Indentures.

Advances for Capacity and Energy – Advance payments to the United States Bureau of Reclamation for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity.

Cash and Cash Equivalents – Cash and cash equivalents include cash and investments with original maturities of 90 days or less.

Unamortized Debt Expenses – Debt premiums, discounts and issue expenses are deferred and amortized to expense over the lives of the related debt issues. Losses on refunding related to bonds redeemed by refunding bonds are amortized over the shorter of the life of the refunding bonds or the remaining term of bonds refunded. Losses on early extinguishment of debt are recognized immediately.

Arbitrage Rebate and Yield Restrictions – The unused proceeds from the issuance of tax-exempt debt have been invested in taxable financial instruments. The excess of earnings on investments, if any, over the amount that would have been earned if the investments had a yield equal to the bond yield or yield restricted rate, is payable to the IRS within five years of the date of the bond offering and each consecutive five years thereafter until final maturity of the related bonds.

The recorded liability of the Multiple Project Fund of $15.9 million ($4.2 million payable to the Mead-Phoenix Project and $11.7 million payable to the Mead-Adelanto Project) is a result of the cumulative savings from the 1994 refunding of the 1989 Multiple Project Bonds. The partial refunding within five years of the original issuance triggered a recalculation of the arbitrage yield, reducing the Multiple Project Fund's rebate liability.

During the fiscal year ended June 30, 2004, the Authority made rebate payments to the IRS of $0.6 million for the STS bonds, $0.4 million for Mead-Phoenix bonds, and $1.2 million for the Mead-Adelanto bonds.

Recorded arbitrage rebate and yield restriction liabilities as of June 30, 2004, were $1.1 million for Palo Verde, $1.3 million for STS, $0.1 million for Mead-Phoenix, and $0.2 million for Mead-Adelanto.

Revenues – Revenues consist of billings to participants for the sales of electric energy and transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the property.

In September 1998, the Palo Verde participants approved a resolution authorizing the Authority to bill the participants an additional $65 million annually through June 30, 2004 to pay for increased debt service costs as a result of a refunding completed in October 1997. In addition, the participants resolved to transfer any overbillings, renewal and replacement excess funds or surplus amounts through June 30, 2004 into the Palo Verde reserve account. On November 20, 2003, the Authority adopted a resolution to utilize the amounts on deposit in the reserve accounts to pay a portion of the operating and maintenance expenses of the Palo Verde Project starting July 1, 2004. Funds held in the reserve account as a result of this resolution totaled $55.3 million and $45.5 million as of June 30, 2004 and 2003, respectively.

3. Investments

The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. seq. of the California Government Code, Indentures of Trust, instruments governing financial arrangements entered into by the Authority to finance and operate Projects and the Authority's Investment Policy.

Eligible securities and general limitations are derived from each Project's Indenture of Trust for the issuance of senior and subordinate lien bonds. Additional limitations are derived from the Government Code and the Authority's evolving investment practices.

The operative Indentures of Trust in which securities are authorized for investment purposes relate to the Hoover Uprating Project Bonds, the San Juan Project Bonds, the Palo Verde Project Bonds, the Southern Transmission System Project Bonds, the Mead-Phoenix Project Bonds, the Mead-Adelanto Project Bonds, the Multiple Project Fund Bonds, and the Magnolia Power Project Bonds. Authorized investments for the Projects' Stabilization Fund are set forth in a resolution approved by the Board in 1996.

Eligible securities include:

- United States Treasury Securities, which are bonds or other obligations secured by the full faith and credit of the United States of America;
- Federal Agency Obligations, which have the full financial backing of the U.S. Government;
- Government Sponsored Enterprise Obligations, which are created by acts of Congress to provide liquidity for selected lending programs targeted by Congress;

- Repurchase Agreements, which are collateralized loan contracts where the seller includes a written agreement to repurchase the securities at a later date for a specified amount;
- Negotiable Certificates of Deposit, which are deposit liabilities issued by a nationally or state-chartered bank, a savings or a federal association or by a state-licensed branch of a foreign bank which has a short-term ratings of at least "A-1" by S&P and at least "P-1" by Moody's;
- Banker's Acceptances, a short term draft or bill of exchange guaranteed for payment at face value to the holder of the instrument on its maturity date, which has a short-term rating of at least "A-1" by S&P and at least "P-1" by Moody's;
- Commercial Paper, a short-term unsecured promissory note issued by non-financial or financial firms with a rating of "A-1" by S&P and "P-1" by Moody's;
- Medium Term Notes rated "A" or better and only those issued by corporations organized and operating within the United States, or by depository institutions licensed by the United States or any state and operating within the United States;
- Equity-Linked Notes, which are categorized as medium-term corporate notes and are subject to the constraints set forth in the Government code.

Investments at June 30, 2004 and 2003 are as follows:

	June 30, 2004									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Federal agencies	$ 338,770	$ 49,116	$ 3,922	$ 1,075	$ 2,970	$ –	$ 17,999	$ 42,154	$ 49,935	$ 505,941
U.S. government securities	481,729	10,354	–	–	–	7,435	–	–	–	499,518
Guaranteed investment contracts	–	36,465	–	8,709	23,893	231,404	21,599	93,536	–	415,606
Money market investment account	18,107	1,422	221	681	996	–	(3)	602	548	22,574
Medium term notes	4,460	–	–	–	–	–	–	–	–	4,460
Cash	88	38	16	12	10	–	20	16	407	607
Total	$ 843,154	$ 97,395	$ 4,159	$ 10,477	$ 27,869	$ 238,839	$ 39,615	$ 136,308	$ 50,890	$ 1,448,706
Restricted investments	$ 662,197	$ 56,361	$ 2,358	$ 8,709	$ 23,893	$ 238,839	$ 26,944	$ 128,425	$ 49,935	$ 1,197,661
Non-restricted investments	20,502	–	560	–	–	–	–	–	–	21,062
Cash and cash equivalents	160,455	41,034	1,241	1,768	3,976	–	12,671	7,883	955	229,983
Total	$ 843,154	$ 97,395	$ 4,159	$ 10,477	$ 27,869	$ 238,839	$ 39,615	$ 136,308	$ 50,890	$ 1,448,706

	June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Federal agencies	$ 351,717	$ 40,265	$ 2,955	$ 437	$ 3,283	$ 7,435	$ 15,514	$ 46,945	$ 89,239	$ 557,790
U.S. government securities	420,763	10,337	–	–	–	–	–	–	5,711	436,811
Guaranteed investment contracts	–	36,423	–	9,314	24,898	236,002	21,599	35,397	–	363,633
Money market investment accounts	3,123	9,673	1,253	1,605	2,069	–	397	150,465	1,035	169,620
Medium term notes	4,367	–	–	–	–	–	–	–	–	4,367
Cash	96	40	18	12	12	–	22	–	–	200
Total	$ 780,066	$ 96,738	$ 4,226	$ 11,368	$ 30,262	$ 243,437	$ 37,532	$ 232,807	$ 95,985	$ 1,532,421
Restricted investments	$ 661,929	$ 58,802	$ –	$ 9,751	$ 27,471	$ 243,437	$ 21,602	$ 70,426	$ 53,044	$ 1,146,462
Non-restricted investments	12,995	–	500	–	–	–	–	–	–	13,495
Cash and cash equivalents	105,142	37,936	3,726	1,617	2,791	–	15,930	162,381	42,941	372,464
Total	$ 780,066	$ 96,738	$ 4,226	$ 11,368	$ 30,262	$ 243,437	$ 37,532	$ 232,807	$ 95,985	$ 1,532,421

4. Derivative Instruments

Objective of the swaps. In order to protect against the potential of rising interest rates, the Authority has entered into six separate pay-fixed, receive-variable interest rate swaps at a cost less than what the Authority would have paid to issue fixed-rate debt.

Terms, fair values, and credit risk. The terms, including the fair values and credit ratings of the counterparties under the outstanding swaps as of June 30, 2004, are included below. In most cases, the notional amounts of any swaps match the principal amounts of the associated debt. Except as discussed under the rollover risk, the Authority's swap agreements contain scheduled reductions to outstanding notional amounts that are expected to approximately follow scheduled or anticipated reductions in the associated "bonds payable" category.

- *MP 2004 Swap* - In connection with the issuance of the 2004 Mead-Phoenix Project Revenue Bonds Series A auction-rate security in May 2004, the Authority entered into an interest rate swap on March 3, 2004. The floating-to-fixed rate swap created synthetic fixed-rate debt for the Authority. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 3.894% and in exchange the Authority receives a floating rate index equal to 65% of one-month LIBOR. The swap agreement expires July 1, 2020. The Authority received approximately $1.8 million in an upfront payment in connection with the execution of the swap, which has been deferred and is being amortized as an interest yield adjustment over the life of the option. Approximately $13.5 million in Mead-Phoenix 2004 Project Revenue Bonds Series A are not swapped and remain floating-rate bonds. The floating rate on the related bonds as of June 30, 2004 was 1.00%.

- *MA 2004 Swap* - In connection with the issuance of the 2004 Mead-Adelanto Revenue Bonds Series A auction-rate security in May 2004, the Authority entered into an interest rate swap on March 3, 2004. The floating-to-fixed rate swap created synthetic fixed-rate debt for the Authority. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 3.89% for the swap and in exchange the Authority receives a floating rate index equal to 65% of one-month LIBOR. The swap agreement expires July 1, 2020. The Authority received approximately $5.9 million in an upfront payment in connection with the execution of the swap, which has been deferred and is being amortized as an interest yield adjustment over the life of the option. Approximately $45.1 million in Mead-Adelanto 2004 Project Revenue Bonds Series A are not swapped and remain floating-rate bonds. The average floating rate on the related bonds as of June 30, 2004 was 1.01%.

- *STS 2003 Swap* - In April 2003, the Authority entered into an Interest Rate Swap agreement with a third party for the purpose of hedging against interest rate variations arising from the issuance of the 2003 Subordinate Refunding Series A Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the counterparty on a fixed rate basis of 3.266%, and for the counterparty to make reciprocal payments based on a floating rate of 65% of one-month LIBOR. The floating rate on the related bonds at June 30, 2004 and 2003 was 1.08% and 0.857%, respectively. The agreement expires on July 1, 2022.

- *STS Swaption/Swap* - In February 2001, the Authority entered into a transaction whereby it sold an option (the "Swaption") on a floating-to-fixed interest rate swap. The Swaption was exercised on April 1, 2002. The floating rate on the swap paid by the counterparty is 60% of one-month LIBOR; the annual fixed rate on the swap paid by the Authority is 4.25%. In exchange for the right to exercise the Swaption, the counterparty paid the Authority a one-time up front option premium amount of $7.9 million which has been deferred and is being amortized as an interest yield adjustment over the life of the option. The swap expires on July 1, 2022.

- *STS 2001 Swap* - In June 2001, the Authority entered into an interest rate swap agreement with a counterparty for the purpose of hedging against interest rate variations arising from the issuance of the 2001 Subordinate Refunding Series A Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the counterparty at a fixed rate of 4.24%, and for the counterparty to make reciprocal payments based on a variable rate. The reset dates of the variable rate occur weekly and the rate for a reset date will be the rate determined by the Bond Market Association Municipal Swap Index ("BMA") minus 40 basis points. The counterparty has the option to terminate the agreement on July 5, 2006 and on every Fixed Rate Payer Payment Date, thereafter, should the BMA Index average more than 7% over a consecutive 180-day period. The floating rates on the bonds were 1.00% and .95% at June 30, 2004 and 2003, respectively. The swap expires on July 1, 2021.

(Amounts in thousands)

	Notional Amount	Effective Date	Fixed Rate Paid	Variable Rate Received	Fair Values	Swap Termination Date	Counterparty Credit Rating
MP 2004 Revenue Series A Bonds	28,700	5/27/2004	3.894%	65% of LIBOR	(4,313)	7/1/2020	AA+/Aa2
MA 2004 Revenue Series A Bonds	96,025	5/27/2004	3.890%	65% of LIBOR	(1,301)	7/1/2020	AA+/Aa2
STS 2003 Subordinate Refunding Series A Bonds	51,750	4/24/2003	3.266%	65% of LIBOR	1,351	7/1/2022	AA-/Aa1
STS 2001 Subordinate Refunding Series A Bonds	79,795	6/14/2001	4.240%	BMA less 40 basis points	(7,673)	7/1/2021	AA+/Aa2
STS Swaption/Swap	125,000	2/1/2001	4.250%	60% of LIBOR	(17,734)	7/1/2022	AA-/Aa1
STS 1991 Revenue Bonds Series A	$ 284,200	4/17/1991	6.380%	Bond variable coupon rate	$ (74,940)	6/30/2019	AAA/Aaa
	$ 665,470				$ (104,610)		

- *STS 1991 Swap* - In fiscal year 1991, the Authority entered into an interest rate swap Agreement with a counterparty for the purpose of hedging against interest rate fluctuations arising from the issuance of the 1991 Subordinate Refunding Series Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. Under the Swap Agreement, the Authority pays the counterparty a fixed rate of 6.38%; in exchange, the Authority receives payments mirroring the bond variable coupon rate (1.04% and 0.85% at June 30, 2004 and 2003, respectively). The swap expires on June 30, 2019.

Fair value. All but the 2003 Swap had a negative fair value as of June 30, 2004. These fair values take into consideration the prevailing interest rate environment, the specific terms and conditions of a given transaction and any upfront payments that were received. All fair values were estimated using the zero-coupon discounting method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve are the market's best estimate of future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for a hypothetical zero-coupon rate bond due on the date of each future net settlement on the swaps.

Credit risk. As of June 30, 2004, the Authority was not exposed to counterparty credit risk on its outstanding swaps. For each counterparty, the net fair values of the Authority's applicable swaps were negative. However, should interest rates change and the fair values of the swaps become positive, the Authority would be exposed to credit risk in the amount of the derivatives' fair value.

The swap agreements contain varying collateral agreements with the counterparties. The swaps require full collateralization of the fair value of the swap should the counterparty's (or guarantors of the counterparty, as applicable) credit rating fall below AA- as issued by Standard & Poor's or Aa3 as issued by Moody's Investors Service for the 1991 Swap; A-/A3 for the 2001, the 2003 and the 2004 Swaps; and Baa1/BBB+ for the Swaption/Swap. Collateral on all swaps is to be in the form of US government securities held by a third-party custodian.

The swap agreements provide that when the Authority has more than one derivative transaction with a given counterparty involving the same Authority project (and having the same swap/bond insurer), should one party become insolvent or otherwise default on its obligations, close-out netting provisions permit the nondefaulting party to accelerate and terminate all such related transactions and net the transactions' fair values so that a single sum will be owed by, or owed to, the nondefaulting party.

Basis risk. Basis risk is the risk that the interest rate paid by the Authority on underlying variable rate bonds to bondholders exceeds the variable swap rate received from a counterparty. With the exception of the 1991 Swap, the Authority bears basis risk on each of its swaps. The 1991 Swap is perfectly hedged since the counterparty pays the Authority its actual variable bond rate on the 1991 bonds. All the other Swaps have a basis risk since under each of those swaps the Authority received a percentage of LIBOR (or BMA less 40 basis points) to offset the actual variable bond rate the Authority pays on any related bonds. The Authority is exposed to basis risk should the floating rate that it receives on a swap be less than the actual variable rate the Authority pays on any related bonds. Depending on the magnitude and duration of any basis risk shortfall, the expected cost savings from a swap may not be realized. The 2001 swap is based on BMA rate minus 40 basis points; similar to the LIBOR-based swaps, BMA minus 40 bps may not exactly hedge the underlying variable rate. As of June 30, 2004, the BMA rate was 0.670%, whereas 60% of LIBOR was 0.666%, and 65% of LIBOR was 0.724%. The following is a summary of interest rates paid to and received from the counterparties as of June 30, 2004:

	Type of Derivative					
	1991 Swap	Swaption/ Swap	2001 Swap	2003 Swap	MA 2004 Swap	MP 2004 Swap
Fixed payments to counterparty	6.380%	4.250%	4.240%	3.266%	3.890%	3.894%
Less, variable payments from counterparty	1.040%	0.666%	0.670%	0.724%	0.715%	0.715%
Net interest rate swap payments	5.340%	3.584%	3.570%	2.542%	3.175%	3.179%
Add, variable-rate bond coupon payments	1.040%	1.000%	1.000%	1.080%	1.010%	1.000%
Synthetic interest rate on bonds	6.380%	4.584%	4.570%	3.622%	4.185%	4.179%

Termination risk. The Authority or the counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In addition, the 2001 Swap provides the counterparty with an option to terminate the swap agreement if the consecutive 180-day averaged rate of the BMA index exceeds 7.0%. However, the termination option has a 5-year lockout preventing the swap's termination prior to July 5, 2006. If any of the swaps were terminated, any associated variable rate bonds would no longer be hedged to a fixed rate. If at the time of termination the swap has a negative fair value, the Authority would be liable to the counterparty for a payment equal to the swap's fair value.

Rollover risk. Rollover risk is the risk that the swap contract is not co-terminus with the related bonds. The Authority is exposed to rollover risk on the 2001 swap because the counterparty has the option to terminate the agreement prior to the maturity of the associated debt. In the event that this swap terminates, the Authority would be exposed to variable interest rates on the underlying bonds. The following debt is exposed to rollover risk:

Associated Debt Issuance	Debt Maturity Date	Optional Swap Termination Date
STS 2001 Subordinate Refunding Series A	July 1, 2021	July 5, 2006

Swap payments and associated debt. Using rates as of June 30, 2004, debt service requirements of the Authority's outstanding variable rate debt and net swap payments are as follows. As rates vary, variable rate bond interest payments and net swap payments will vary.

Fiscal Year Ending June 30	Variable-Rate Bonds Principal	Variable-Rate Bonds Interest	Interest Rate Swaps, Net	Total
2005	$ 1,725	$ 6,918	$ 28,122	$ 35,040
2006	5,100	6,866	27,933	34,799
2007	5,300	6,812	27,735	34,547
2008	18,300	6,623	26,845	33,468
2009-2013	138,400	29,557	117,599	147,156
2014-2018	319,095	16,326	62,517	78,843
2019-2022	190,700	2,206	6,983	9,189
	$ 678,620	$ 75,308	$ 297,734	$ 373,042

5. Long-Term Debt

Long-term debt outstanding at June 30, 2004 consisted of "new money" bonds and refunding bonds due in varying annual amounts through 2036. The new money bonds were issued to finance the purchase and construction or acquisition of the Authority's interest in each of the Projects. The subordinate refunding bonds were issued to refund specified new money bonds. The Multiple Project Revenue Bonds were issued on January 4, 1990 to finance acquisition of ownership interests in one or more Projects expected to be undertaken within five years after issuance. In October 1992, $103.6 million and $285.0 million of these bonds were transferred to the Mead-Phoenix Project accounts and the Mead-Adelanto Project accounts, respectively.

In accordance with the bond indentures, the new money bonds and refunding bonds are special, limited obligations of the Authority. With the exception of the Magnolia Power Project B, Lease Revenue bonds (City of Cerritos, California) 2003-1 ("Project B Bonds"), the bonds issued by each project are payable solely from and secured solely by interests in that project as follows:

- Proceeds from the sale of bonds;
- All revenues, incomes, rents and receipts attributable to that project and interest earned on securities held under the bond indenture or indentures; and
- All funds established by the indenture or indentures.

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the power and transmission sales agreements with the participants. At the option of the Authority, all outstanding new money bonds and refunding bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A and portions of the 1989A, 1992B and 1993A Refunding Series bonds issued for the Palo Verde Project; the 1996 Subordinate Refunding Series A bonds, the 2002 Subordinate Refunding Series B bonds, and portions of the 1988A Refunding and 1992 Subordinate Refunding bonds issued for the Southern Transmission System; and a total of $125.5 million of the Multiple Project Revenue Bonds.

Revenue Bonds

Magnolia Power Project Revenue Bonds – To finance the acquisition and construction of the Magnolia Power Project, the Authority, in April 2003, issued $300.0 million Magnolia Power Project A, Revenue Bonds, 2003-1 ("Project A Bonds"). Simultaneously with the issuance of the Project A Bonds, the Authority issued $14.1 million Project B Bonds. The Project Manager expects that proceeds of both the Project A and Project B Bonds, together with applicable interest earnings, will be sufficient to pay all costs necessary to construct and acquire the Project.

The Project B Bonds will be secured by lease rental payments to be made by the City of Cerritos (the "City") in connection with the lease of certain facilities and premises owned by the City to the Authority and the leaseback of such facilities and premises to the City. The Base Rental Payments will be equal to the principal and interest on the Project B Bonds. In accordance with the Assignment Agreement between the Authority and the Trustee, the Authority will assign certain of its rights under the Lease, including its right to receive the Base Rental Payments, to the Trustee for the benefit of the Owners of the Project B Bonds.

The City has covenanted to budget and appropriate sufficient funds to make all payments required to be made under the Lease. The Lease has a term of 55 years.

The bonds mature on July 1, 2036.

Refunding Bonds

Mead-Adelanto/Mead-Phoenix Project Refunding Bonds – On May 27, 2004, the Authority issued $141.2 million of the 2004 Mead-Adelanto refunding bonds and $42.2 million of the Mead-Phoenix refunding bonds (the "2004 Refunding Bonds") to refund $141.2 million of Mead-Adelanto 1994 Series A Bonds and $42.2 million of Mead-Phoenix 1994 Series A Bonds (collectively, the "Refunded Bonds"). Funds released from the debt service accounts related to the Refunded Bonds were approximately $2.8 million and $850,000 for the Mead-Adelanto and Mead-Phoenix bonds, respectively. The Refunded Bonds were redeemed on July 1, 2004.

The 2004 Bonds were issued as Auction Rate Certificates ("ARCs"). They will bear interest from the date of delivery of the bonds to July 1, 2020. These bonds bear interest at the applicable auction rate and will generally reset every seven (7) days. In addition, approximately $96.0 million of Mead-Adelanto bonds and $28.7 million of Mead-Phoenix bonds are swapped to create synthetic fixed rate obligations. The swap agreements obligate the Authority to pay to the counterparty an annual interest rate of 3.89% and 3.894% under the Mead-Adelanto and the Mead-Phoenix swap agreements, respectively. In exchange, the Authority receives 65% of one-month LIBOR under each of the swap agreements (See Note 4). Approximately $45.1 million of Mead-Adelanto and $13.5 million of Mead-Phoenix 2004 Bonds are not swapped and remain floating-rate bonds.

This transaction resulted in a net loss for accounting purposes of $26.4 million, consisting primarily of the write-off of unamortized debt expense and the discount associated with the Refunded Bonds. The Authority has proportionally allocated this loss between bonds refunded through funds released from debt service accounts and through the issuance of refunding bonds. The loss allocated to the new bonds of $25.9 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $508,000 extraordinary loss in fiscal year 2004.

San Juan Unit 3 Project Refunding – In October 2002, the Authority issued $71.85 million par value SJ 2002 Refunding Series B Bonds ("refunding bonds") to refund $70.8 million of SJGS 1993 Series A Bonds ("refunded bonds"). The refunding bonds are being issued as Auction Rate Certificates ("ARCs"). The initial interest period of the refunding bonds commenced from the date of delivery of the bonds and ends on January 1, 2012. During this period the interest payable on the bonds will accrue at 5.25% per annum. After the initial interest period, the refunding bonds will bear interest at the applicable Auction Rate. The Auction Dates for the 2002 Series B Bonds will generally occur every thirty-five (35) days.

This transaction resulted in a net loss for accounting purposes of $6.0 million, consisting primarily of the write-off of unamortized debt expense and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of refunding bonds. The loss allocated to the new bonds of $6.0 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $74,000 extraordinary loss in fiscal year 2003.

Subordinate Refunding Bonds

Southern Transmission Project Refunding – In May 2003, the Authority issued $51.75 par value STS 2003 Subordinate Refunding Series A ("refunding bonds") to refund $58.5 million of STS 1993 Subordinate Refunding Series A Bonds ("refunded bonds"). Funds released from the debt service accounts related to the refunded bonds were $9.8 million. The refunded bonds were redeemed on July 1, 2003. The refunding was expected to reduce total debt service payments over the life of the refunding issue by approximately $13.3 million and was expected to result in present value savings of approximately $9.9 million based on an average cost of 3.27% on the new bonds.

The refunding bonds are issued as Auction Rate Securities bearing interest at a weekly Auction Rate (0.85% at June 24, 2003) as determined by the Auction Agent. The Authority entered into an interest rate swap agreement to fix the interest rate at 3.266% (see Note 4).

This transaction resulted in a net loss for accounting purposes of $9.8 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refundings and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds of $8.2 million was deferred and will be amortized over the life of the new bonds. The por-

tion refunded with cash resulted in immediate recognition of a $1.6 million extraordinary loss in fiscal year 2003.

In October 2002, the Authority issued $38.8 million par value STS 2002 Subordinate Refunding Series B Bonds ("refunding bonds") to refund $46.4 million of STS 1992 Subordinate Refunding Series A Bonds ("refunded bonds"). The remaining $5.2 million was funded from debt service accounts related to the refunded bonds and $2.1 million from the General Reserve Fund. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $8.7 million and is expected to result in present value savings of approximately $7.3 million based on an average cost of 4.57% on the new bonds. The refunded bonds were redeemed in December 2002.

This transaction resulted in a net loss for accounting purposes of $5.93 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refundings and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds of $5.03 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of an $892,000 extraordinary loss in fiscal year 2003.

Advance Refundings – In prior years, the Authority established irrevocable escrow trusts with the proceeds from issuance of subordinate refunding bonds. These investments will be used to pay specified revenue bonds called at scheduled redemption dates.

Prior Year Defeasance of Debt – In prior years, the Authority defeased specified revenue bonds by placing the proceeds from the issuance of subordinate refunding bonds in irrevocable trusts to provide for all future debt service payments on the refunded bonds. The trust investments and related liability for bonds that are considered legally defeased are not included in the Authority's financial statements. At June 30, 2004 and 2003, $334.4 million and $555.9 million, respectively, of revenue bonds outstanding are considered legally defeased.

Palo Verde Nuclear Generating Station (PVNGS) – In 1997, the Authority began taking steps designed to accelerate the payment schedule of all fixed rate subordinate bonds relating to PVNGS so that they would be paid off by July 1, 2004 (the "Restructuring Plan"). Certain outstanding bonds were refunded for savings and the project participants accelerated payments on the bonds issued by the Authority for PVNGS. The Restructuring Plan is expected to result in substantial savings to the PVNGS project participants once the principal and interest on these fixed rate subordinate bonds have been paid. The Restructuring Plan is substantially completed and has resulted in increased payments (approximately $65 million per year) since 1997. Nearly all of these payments have already been made. Final payment in fulfillment of the Restructuring Plan was made on July 1, 2004.

In March 2003, the Palo Verde 1993 Escrow Funds, which were created to defease to maturity certain of the Palo Verde 1993 Refunding Series A and 1993 Subordinate Refunding Series Bonds (together the "1993 Defeased Bonds") were restructured for the purpose of redeeming the 1993 Defeased Bonds on July 1, 2003. This was Phase 1 of the Authority's Palo Verde Escrow Restructuring Plan (the "Escrow Restructuring").

On August 25, 2003, Phase II of the Escrow Restructuring was completed. Previously, proceeds from the Palo Verde 1997 Series B Bonds were used to create the Palo Verde 1992 Series B Bonds and 1992 Series C Bonds – Escrow Securities Fund (the "1992 B and C Escrow Fund"), to defease to maturity portions of the 1992 Refunding Series B (the "1992 Series B Defeased Bonds") and the 1992 Refunding Series C Bonds (the "1992 Series C Defeased Bonds"). Phase II of the Escrow Restructuring allowed for the restructuring of these securities and in August 2003, the Escrow Securities comprising the 1992 B and C Escrow Fund were sold. Proceeds from the sale were used to purchase new securities that were deposited into the 1992 Series B and C Escrow Fund. The new 1992 Escrow Securities were used to redeem the 1992 Series B Defeased Bonds on September 25, 2003, and subsequently to pay to maturity the 1992 Series C Defeased Bonds.

In total, Phase I and Phase II of the transaction resulted in a gain of nearly $17.3 million, net of related expenses of $636,000.

For accounting purposes, this gain is being deferred and amortized as downward yield adjustment over the life of the debt used to defease the 1992 Series B Defeased Bonds and the 1992 Series C Defeased Bonds. The funds were used to pay a portion of the 2004 fiscal year debt service and capital improvements in the amounts of $7.6 and $8.9 million, respectively.

A summary of changes in long-term debt follows:

	(Amounts in thousands)								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Total
Total Long-term debt at June 30, 2003	$ 609,150	$ 807,669	$ 19,404	$ 64,224	$ 207,307	$ 216,445	$ 200,699	$ 321,730	$ 2,446,628
Total Debt due within one year at June 30, 2003	49,190	29,720	1,190	–	–	7,100	8,390	–	95,590
Total Debt at June 30, 2003	658,340	837,389	20,594	64,224	207,307	223,545	209,089	321,730	2,542,218
Principal payments	(49,190)	(29,720)	(1,190)	–	–	(7,100)	(8,390)	–	(95,590)
Revenue bonds issued	–	–	–	42,225	141,150	–	–	–	183,375
Bonds refunded	–	–	–	(42,235)	(141,155)	–	–	–	(183,390)
Refunding bonds issued	–	–	–	–	–	–	–	–	–
Decrease in Unamortized debt-related costs, net	11,700	16,088	401	1,249	3,559	679	(617)	(403)	32,656
Total Debt at June 30, 2004	$ 620,850	$ 823,757	$ 19,805	$ 65,463	$ 210,861	$ 217,124	$ 200,082	$ 321,327	$ 2,479,269
Total Debt due within one year at June 30, 2004	(51,800)	(28,535)	(1,230)	–	–	(7,600)	(8,805)	–	(97,970)
Total Long-term debt at June 30, 2004	$ 569,050	$ 795,222	$ 18,575	$ 65,463	$ 210,861	$ 209,524	$ 191,277	$ 321,327	$ 2,381,299

Unamortized debt-related costs, net are as follows as of June 30,2004 (amounts in thousands):

Unamortized debt-related costs, net:	Loss on Refunding	(Premium) Discount	Total
Palo Verde Project	$ 34,871	$ 56,544	$ 91,415
Southern Transmission System Project	116,452	28,146	144,598
Hoover Uprating Project	3,163	(378)	2,785
Mead-Phoenix Project	7,204	(763)	6,441
Mead-Adelanto Project	21,428	(3,119)	18,309
Multiple Project Fund	–	10,876	10,876
San Juan Project	10,148	(14,810)	(4,662)
Magnolia Power Project	–	(7,247)	(7,247)
	$ 193,266	$ 69,249	$ 262,515

The scheduled debt service payments for future years ending June 30, are included in the table below. The variable rates used for the PV 1996 Subordinate Refunding Series B and C, and the STS 1996 Subordinate Refunding Series B were the rates at June 30,2004 of 1.04% and 0.85%, respectively. The variable rates are set by the bond remarketing agent on a weekly basis based on economic conditions and bond ratings. The variable rate used for the SJ 2002 Revenue Refunding Series B was assumed at 4% per annum starting in January 1,2012.

Fair Value – The fair value of the Authority's long-term debt (including the current portion) is approximately $2.8 billion and $3.0 billion at June 30, 2004 and 2003, respectively. Management has estimated fair value based on the quoted market prices for the same or similar issues or on the current average rates offered to the Authority for debt of approximately the same remaining maturities, excluding the effect of a related interest rate swap agreement.

		(Amounts in thousands)								
		Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Total
2005	Principal	51,800	28,535	1,230	–	–	7,600	8,805	–	97,970
	Interest	28,537	37,381	987	3,306	10,280	13,864	10,013	15,170	119,538
2006	Principal	–	31,470	1,275	–	–	8,100	9,160	–	50,005
	Interest	28,537	36,844	943	3,306	10,280	13,297	9,631	15,170	118,008
2007	Principal	–	34,230	1,315	3,250	10,850	–	9,570	3,735	62,950
	Interest	28,537	36,279	893	3,224	10,009	13,297	9,186	15,096	116,521
2008	Principal	–	30,950	1,370	3,350	11,150	–	10,050	4,520	61,390
	Interest	28,537	34,668	838	3,141	9,730	13,297	8,695	15,005	113,911
2009	Principal	28,815	31,550	1,425	3,425	11,400	–	10,550	4,610	91,775
	Interest	28,238	32,909	782	3,055	9,445	13,297	8,161	14,896	110,783
2010-2014	Principal	108,195	202,015	8,045	23,580	66,945	88,700	75,435	25,535	598,450
	Interest	139,630	135,144	2,932	11,557	36,738	44,809	28,767	71,478	471,055
2015-2019	Principal	523,455	261,990	7,930	26,150	88,125	83,100	59,975	32,010	1,082,735
	Interest	81,001	83,655	755	4,573	15,293	31,082	7,655	64,413	288,427
2020-2024	Principal	–	347,615	–	12,150	40,700	40,500	11,875	41,075	493,915
	Interest	–	17,769	–	241	808	2,227	237	54,937	76,219
2025-2029	Principal	–	–	–	–	–	–	–	52,400	52,400
	Interest	–	–	–	–	–	–	–	43,044	43,044
2030-2034	Principal	–	–	–	–	–	–	–	66,880	66,880
	Interest	–	–	–	–	–	–	–	27,842	27,842
2035-2037	Principal	–	–	–	–	–	–	–	83,315	83,315
	Interest	–	–	–	–	–	–	–	5,977	5,977
	Principal	$ 712,265	$ 968,355	$ 22,590	$ 71,905	$ 229,170	$ 228,000	$ 195,420	$ 314,080	$ 2,741,785
	Interest	$ 363,017	$ 414,649	$ 8,130	$ 32,403	$ 102,583	$ 145,170	$ 82,345	$ 343,028	$ 1,491,325
Effective costs of capital		5.90%	4.34%	4.28%	4.26%	4.13%	6.56%	3.76%	4.71%	

6. Net Assets (Deficit)

As a result of the adoption of GASB 34, costs recoverable, deferred credits and funds due to participants were reclassified to net assets (deficit) in accordance with this statement.

Costs Recoverable – Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. The difference between billings and the Authority's expenses calculated in accordance with generally accepted accounting principles are deferred as costs recoverable in future periods and are presented as net assets (deficit). It is intended that the deferred amounts will be recovered through billings for repayment of principal on the related bonds.

Deferred Credits – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto. The remaining funds are held in the Multiple Project Fund. Deferred credits represent the accumulated net earnings of the fund.

Funds Due to Participants – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Monies deposited by the participants to this Fund are used to pay for Authority costs as directed by the participants. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust. Funds due to Participants represent the net amount of contributions and net earnings on the invested contributed funds.

Net assets (deficit) are comprised of the following (in thousands):

	(Amounts in thousands)				
	June 30, 2002	Fiscal Year 2003 Activity	June 30, 2003	Fiscal Year 2004 Activity	June 30, 2004
GAAP items not included in billings to participants:					
Depreciation of plant	$ (752,061)	$ (62,325)	$ (814,386)	$ (53,687)	$ (868,073)
Nuclear fuel amortization	(19,548)	–	(19,548)	–	(19,548)
Decommissioning expense	(125,246)	(6,009)	(131,255)	(6,009)	(137,264)
Amortization of bond discount, debt issue costs, and loss on refundings	(549,360)	(35,096)	(548,456)	(31,294)	(615,750)
Interest expense	(63,931)	1,654	(62,277)	(7,371)	(69,648)
Bond requirements included in billings to participants:					
Operations and maintenance, net of investment income	175,575	99,330	274,905	9,227	284,132
Costs of acquisition of capacity	18,769	1,153	19,922	(1,224)	18,698
Billings to amortize costs recoverable	281,230	50,410	331,640	50,410	382,050
Reduction in debt service billings due to transfer of excess funds	(90,020)	–	(90,020)	–	(90,020)
Principal repayments	693,447	86,871	780,318	82,203	862,521
Other	57,796	7,833	65,629	3,579	69,208
	(373,349)	143,821	(229,528)	45,834	(183,694)
Multiple Project Fund Net Assets	6,355	337	6,692	415	7,107
Projects' Stabilization Fund Net Assets	173,785	(77,364)	96,421	(44,966)	51,455
	$ (193,209)	$ 66,794	$ (126,415)	$ 1,283	$ (125,132)

7. Commitments and Contingencies

Deregulation – When Assembly Bill 1890 (the "Bill") passed in September 1996, the electric industry became chaotic. The investor owned utilities' (IOUs) creditworthiness deteriorated to a point where one went bankrupt as a result of compliance with the Bill. The deregulation experiment has, for the most part, been abandoned and the IOU situation is improving. The public power systems in the Authority were not required to comply with the Bill's provisions and continued to plan for the needs of their customers and were not faced with customers choosing direct access and leaving the system. Most of the Authority's members have made investment in new gas-fired peaking or base-load generation located in Southern California. The members continue to collect the public benefit charge, and to date have instituted in excess of $500 million of programs to benefit their customers. The local governing authority makes the decisions on how these funds are allocated. Funds (approximately 2.95% of gross revenues) have been spent on renewable resources, conservation, research and development, and low-income rate subsidies. The Authority cannot predict the impact of any future direct access or deregulation programs on energy markets or its participants.

Nuclear Spent Fuel and Waste Disposal – Under the Nuclear Waste Policy Act, the Department of Energy ("DOE") was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but the DOE has announced that such a repository now cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

In July 2002, a measure was signed into law designating the Yucca Mountain in the state of Nevada as the nation's high-level nuclear waste repository. This means the DOE can now file a construction and operation plan for Yucca Mountain with the Nuclear Regulatory Commission ("NRC"). The DOE expects that the Yucca Mountain site will be open by 2010. The State of Nevada and its congressional delegation are determined to halt the project through the NRC process or through legal challenges.

Feud over funding of the repository, however, ensues. The Administration and Congressional leaders continue to push for full and adequate funding, in order for the DOE to meet the application deadline of 2004. The Nevada delegation has been working diligently to try to delay the DOE's work on the license application for the Yucca site, in hopes of halting the transfer of nuclear waste to the Nevada facility.

The spent fuel storage in the wet pool at PVNGS exhausted its capacity in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $2 million for the Authority). In addition to the facility, the costs also account for heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The facility has the capacity to store all the spent fuel generated by the plant until 2026, the end of its lifetime. To date, 18 casks, each containing 24 spent fuel assemblies, were placed in the Storage Facility. The current plan calls for the removal of between 240 and 288 fuel assemblies from the units to the Storage Facility every year. The costs incurred by the procurement, packing, preparation and transportation of the casks are included as part of the fuel expenses, and would cost approximately $12 million a year (about $700,000 for the Authority). If the permanent repository in Yucca Mountain is opened as scheduled in 2010, the spent fuel from PVNGS will be shipped to the repository starting in 2031.

Nuclear Insurance – The Price-Anderson Act (the "Act") requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to approximately $10.8 billion per incident. Participants in the Palo Verde Nuclear Generating Station currently insure potential claims and liability through commercial insurance with a $300 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to $101 million per reactor for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million per reactor, per incident, per year. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $17.8 million, limited to payments of $1.8 million per incident, per year.

Other Legal Matters – With respect to the San Juan Generating Station (including the Authority's ownership interest in Unit 3 thereof), the Sierra Club and the Grand Canyon Trust have filed suit against Public Service Company of New Mexico ("PNM") in federal court alleging violations of the Clean Air Act and of the conditions of the San Juan Generating Station's operating permit. PNM is a co-owner of the San Juan Generating Station and is the operating agent of the station. The lawsuit seeks penalties as well as injunctive and declaratory relief. The Authority is not a defendant in the litigation. However, if the plaintiffs prevail in the litigation, the Authority may be required to pay a portion of any damages resulting from the litigation.

PNM has informed the Authority that it is vigorously defending against the plaintiffs' claims. If the matter goes to trial, PNM will present its case that the violations were not of such a nature as to require large penalties or injunctive relief. The Authority is unable to predict the outcome of this litigation.

Claims and a lawsuit for damages have been filed with the Authority, Intermountain Power Authority (the "IPA") and the LADWP seeking $100 million in special damages and a like amount in general damages. The claimants allege, among other things, that due to improper grounding of the transmission line of STS, their dairy herds were damaged and the value of their land was diminished. The claimants also seek injunctive relief. The Authority, IPA and the LADWP intend to vigorously defend the claims.

The Authority is also involved in various other legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position or the results of operations of the Authority or the respective separate Projects.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Debt Service Fund	Debt Service Reserve Fund	Decom-missioning Trust Fund	Deposit Installment	Deposit Reserve Installment	Escrow Account	General Reserve Account	Issue Account	Operating Account	Reserve & Contingency	Revenue Fund	Total
Balance at June 30, 2003	$ 30,701	$ 34,651	$ 116,305	$ 6,161	$ 1,000	$ 709,471	$ 1,879	$ 53,459	$ 22,051	$ 91,412	$ 244	$1,067,334
Additions:												
Investment earnings	–	780	3,992	–	19	500	–	61	233	593	1	6,179
Discount on investment purchases	235	29	75	34	2	5,827	–	360	43	874	7	7,486
Distribution of investment earnings	(285)	(947)	–	(27)	(22)	–	3	(466)	(526)	(2,197)	4,474	7
Revenue from power sales	–	–	–	–	–	–	–	–	–	–	174,793	174,793
Distribution of revenue	22,295	–	8,004	–	–	–	108,860	–	40,041	–	(179,200)	–
Transfer from escrow fund for principal and interest payments	259,743	–	–	–	–	(366,796)	–	107,053	–	–	–	–
Transfer from escrow restructuring	571	–	–	–	–	(627)	–	–	56	–	–	–
Other	(6,212)	–	–	–	(2)	50,373	(110,742)	55,874	388	10,213	223	115
Total	276,347	(138)	12,071	7	(3)	(310,723)	(1,879)	162,882	40,235	9,483	298	188,580
Deductions:												
Construction expenditures	–	–	–	–	–	–	–	–	–	8,670	–	8,670
Operating expenditures	–	–	3	–	–	–	–	–	28,108	–	–	28,111
Debt issue cost	–	–	–	–	–	125	–	–	–	–	–	125
Remarketing/Commitment Fees	–	–	–	–	–	–	–	458	–	–	–	458
Fuel costs	–	–	–	–	–	–	–	–	8,011	–	–	8,011
Payment of principal	12,595	–	–	–	–	–	–	36,595	–	–	–	49,190
Interest paid - non-escrow	4,456	–	–	–	–	–	–	27,735	–	–	–	32,191
Payment of principal and interest paid - escrow	259,743	–	–	–	–	–	–	107,053	–	–	–	366,796
Total	276,794	–	3	–	–	125	–	171,841	36,119	8,670	–	493,552
Balance at June 30, 2004	$ 30,254	$ 34,513	$ 128,373	$ 6,168	$ 997	$ 398,623	$ –	$ 44,500	$ 26,167	$ 92,225	$ 542	$ 762,362

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost for both on balance sheet funds and off balance sheet escrows for legally defeased debt. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, $88 and $96 held in the revolving fund at June 30, 2004 and 2003, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Debt Service Fund	Escrow Fund	General Reserve Fund	Issue Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2003	$ 4,537	$ 81,680	$ 2	$ 74,236	$ 524	$ –	$ 160,979
Additions:							
Investment earnings	1	–	–	2,818	1	5	2,825
Discount on investment purchases	57	–	–	217	3	9	286
Distribution of investment earnings	(58)	–	–	(3,035)	(4)	3,097	–
Revenue from transmission sales	–	–	–	–	–	87,653	87,653
Distribution of revenue	11,161	–	(2)	57,706	21,899	(90,764)	–
Transfer from/to escrow fund required by refunding bonds issuance	6,545	(66,993)	–	60,448	–	–	–
Total	17,706	(66,993)	(2)	118,154	21,899	–	90,764
Deductions:							
Operating expenses	–	–	–	73	18,903	–	18,976
Debt issue cost	–	–	–	220	–	–	220
Payment of principal	11,095	–	–	18,625	–	–	29,720
Interest and arbitrage paid	–	–	–	40,657	573	–	41,230
Principal and interest paid on escrow bonds	–	–	–	60,448	–	–	60,448
Total	11,095	–	–	120,023	19,476	–	150,594
Balance at June 30, 2004	$ 11,148	$ 14,687	$ –	$ 72,367	$ 2,947	$ –	$ 101,149

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $38 and $40 held in the revolving fund at June 30, 2004 and 2003, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Escrow Fund	General Reserve Fund	Advance Payment Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2003	$ 1,181	$ –	$ –	$ 1,701	$ 3	$ 1,322	$ –	$ 4,207
Additions:								
Investment earnings	–	–	–	–	–	10	1	11
Discount on investment purchases	5	–	–	26	–	9	–	40
Distribution of investment earnings	(5)	–	–	(27)	–	(19)	50	(1)
Revenue from power sales	–	–	–	–	–	–	2,428	2,428
Distribution of revenues	1,973	–	–	–	–	300	(2,273)	–
Total	1,973	–	–	(1)	–	300	206	2,478
Deductions:								
Operating expenses	–	–	–	–	–	254	–	254
Payment of principal	1,190	–	–	–	–	–	–	1,190
Interest paid	1,040	–	–	–	–	–	–	1,040
Total	2,230	–	–	–	–	254	–	2,484
Balance at June 30, 2004	$ 924	$ –	$ –	$ 1,700	$ 3	$ 1,368	$ 206	$ 4,201

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $16 and $18 held in the revolving fund at June 30, 2004 and 2003, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Revenue Fund	Cost of Issuance	Escrow Account	Total
Balance at June 30, 2003	$ –	$ 3,513	$ 5,911	$ 107	$ 1,818	$ –	$ –	$ –	$ 11,349
Additions:									
Investment earnings	–	141	435	–	128	–	–	–	704
Distribution of investment earnings	–	431	(435)	–	(627)	631	–	–	–
Transmission revenue	–	–	–	–	–	4,515	–	–	4,515
Refunds from operating manager	–	–	–	8	–	–	–	–	8
Transfer of revenues	–	3,701	–	1,569	35	(5,305)	–	–	–
Payments from Western Area Power Administration	–	–	–	–	–	159	–	–	159
Balance transfer to/from escrow account	–	(688)	–	–	–	–	630	58	–
Bond proceeds	–	–	–	–	–	–	–	44,003	44,003
Other transfers	–	(405)	4	476	(71)	–	–	–	4
Total	–	3,180	4	2,053	(535)	–	630	44,061	49,393
Deductions:									
Operating expenses		–	–	1,281	12	–	–	–	1,293
Arbitrage paid	–	–	–	428	–	–	–	–	428
Debt issuance costs	–	–	–	–	–	–	572	–	572
Interest paid		3,924	–	–	–	–	–	–	3,924
Total	–	3,924	–	1,709	12	–	572	–	6,217
Balance at June 30, 2004	$ –	$ 2,769	$ 5,915	$ 451	$ 1,271	$ –	$ 58	$ 44,061	$ 54,525

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $12 held in the revolving fund at both June 30, 2004 and 2003.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Revenue Fund	Surplus Fund	Escrow Account	Cost of Issuance	Total
Balance at June 30, 2003	$ –	$ 6,984	$ 16,267	$ 162	$ 6,826	$ –	$ –	$ –	$ –	$ 30,239
Additions:										
Investment earnings	–	144	1,196	1	501	–	–	–	–	1,842
Discount on investment earnings	–	27	–	–	–	–	–	–	–	27
Distribution of investment earnings	–	1,180	(1,196)	–	(919)	935	–	–	–	–
Transmission revenue	–	–	–	–	–	13,712	–	–	–	13,712
Refunds from operating manager	–	–	–	8	–	–	–	–	–	8
Distribution of revenues	–	11,305	–	3,249	128	(14,682)	–	–	–	–
Payments from Western Area Power Administration	–	–	–	–	–	35	–	–	–	35
Balance transfer to/from escrow account	–	(2,302)	–	–	–	–	–	195	2,107	–
Bond proceeds	–	–	–	–	–	–	–	147,064	–	147,064
Other transfers	–	(1,211)	–	1,211	–	–	–	–	–	–
Total	–	9,143	–	4,469	(290)	–	–	147,259	2,107	162,688
Deductions:										
Interest paid	–	12,358	–	–	–	–	–	–	–	12,358
Arbitrage paid	–	–	–	1,211	–	–	–	–	–	1,211
Debt issuance costs	–	–	–	–	–	–	–	–	1,913	1,913
Operating expenses	–	–	–	2,328	–	–	–	–	–	2,328
Total	–	12,358	–	3,539	–	–	–	–	1,913	17,810
Balance at June 30, 2004	$ –	$ 3,769	$ 16,267	$ 1,092	$ 6,536	$ –	$ –	$ 147,259	$ 194	$ 175,117

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, $10 and $12 held in the revolving fund at June 30, 2004 and 2003, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MULTIPLE PROJECT FUND
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Proceeds Account	Debt Service Account	Earnings Account	Total
Balance at June 30, 2003	$ 242,250	$ –	$ 1,187	$ 243,437
Additions:				
Investment earnings	17,087	12	43	17,142
Transfer of investment earnings to earnings account	(21,769)	–	21,769	–
Transfer to debt service account	–	22,999	(22,999)	–
Total	(4,682)	23,011	(1,187)	17,142
Deductions:				
Interest paid	–	14,640	–	14,640
Payment of principal	–	7,100	–	7,100
Total	–	21,740	–	21,740
Balance at June 30, 2004	$ 237,568	$ 1,271	$ –	$ 238,839

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Escrow Account	Cost of Issuance Fund	Operating Fund	Reserve & Contingency Fund	General Reserve Fund	Revenue Fund	Total
Balance at June 30, 2003	$ 5,383	$ 21,599	$ –	$ –	$ 1,207	$ 8,639	$ 681	$ –	$ 37,509
Additions:									
Investment earnings	1	1,123	–	–	1	44	5	3	1,177
Discount on investments	39	–	–	–	22	52	2	5	120
Distribution of investment earnings	(40)	(1,123)	–	–	(23)	(96)	(7)	1,289	–
Revenue from power sales	–	–	–	–	–	–	–	65,055	65,055
Distribution of revenues	18,812	–	–	–	46,716	824	–	(66,352)	–
Bond proceeds	–	–	–	–	–	–	–	–	–
Transfer from escrow for principal and interest payments	–	–	–	–	–	–	–	–	–
Transfer to escrow funds required by refunding bond issuance	–	–	–	–	–	–	–	–	–
Other	–	–	–	–	–	–	–	–	–
Total	18,812	–	–	–	46,716	824	–	–	66,352
Deductions:									
Operating expenses	–	–	–	–	43,104	–	–	–	43,104
Construction expenditures	–	–	–	–	–	2,154	–	–	2,154
Debt issue cost	–	–	–	–	–	–	–	–	–
Payment of principal	8,390	–	–	–	–	–	–	–	8,390
Interest paid – non-escrow	10,605	–	–	–	–	–	–	–	10,605
Payment of principal and interest – escrow	–	–	–	–	–	–	–	–	–
Total	18,995	–	–	–	43,104	2,154	–	–	64,253
Balance at June 30, 2004	$ 5,200	$ 21,599	$ –	$ –	$ 4,819	$ 7,309	$ 681	$ –	$ 39,608

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $20 and $22 held in the revolving fund at June 30, 2004 and 2003, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MAGNOLIA POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2004
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Project Fund	Operating Reserve Fund	Reserve & Contingency Fund	Total
Balance at June 30, 2003	$ 33,055	$ 19,548	$ 164,979	$ 4,994	$ 9,964	$ 232,540
Additions:						
Investment earnings	459	476	2,735	141	300	4,111
Bond proceeds	–	–	–	–	–	–
Other	–	–	122	–	–	122
Total	459	476	2,857	141	300	4,233
Deductions:						
Construction expenditures	–	–	88,054	–	–	88,054
Interest paid - non-escrow	12,052	–	–	–	–	12,052
Debt issue cost	–	–	12	–	–	12
Premium and interest paid on investment purchases	–	–	–	–	–	–
Total	12,052	–	88,066	–	–	100,118
Balance at June 30, 2004	$ 21,462	$ 20,024	$ 79,770	$ 5,135	$ 10,264	$ 136,655

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost. These balances do not include accrued interest receivable and unrealized gain (loss) on investment and $16 held in the revolving fund at June 30, 2004.

City of Anaheim

Customers - Retail 110,567
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 974,395
Purchased 2,603,955
Total 3,578,350
Total Revenues (000s) $295,988*
Operating Costs (000s) $278,307*
*Unaudited

City of Azusa

Customers Served 15,446
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 282,630
Sales
Retail 265,672
Total Revenues (000s) $26,870*
Operating Costs (000s) $22,378*
*Unaudited

City of Banning

Customers Served 11,636
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 161,100
Total 161,100
Total Revenues (000s) $19,550*
Operating Costs (000s) $18,709*
*Unaudited

City of Burbank

Customers Served 51,360
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 115,138
Purchased 1,036,996
Total 1,152,134
Total Revenues (000s) $271,175*
Operating Costs (000s) $237,763*
*Unaudited

City of Cerritos

Customers Served 15,091
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 10
Purchased ..... To be determined
Total Revenues (000s) $0
Operating Costs (000s) $0

City of Colton

Customers Served 17,918
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 43,266
Purchased 322,734
Total 366,000
Total Revenues (000s) $40,867*
Operating Costs (000s) $42,686*
*Unaudited

City of Glendale

Customers Served 83,232
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 161,385
Purchased 1,190,385
Total 1,351,770
Total Revenues (000s) $171,278*
Operating Costs (000s) $134,790*
*Unaudited

Imperial Irrigation District

Customers Served 120,500
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 1,044,015
Purchased 1,985,331
Total 3,029,346
Total Revenues (000s) $435,000
Operating Costs (000s) $427,000

Los Angeles Department of Water and Power

Customers Served 1,428,435
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 13,321,613
Purchased 13,588,932
Total 26,910,545
Total Revenues (000s) $2,323,535*
Operating Costs (000s) $2,057,322*
*Unaudited

City of Pasadena

Customers Served 61,057
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 142,225
Purchased 1,369,944
Total 1,512,169
Total Revenues (000s) $177,250
Operating Costs (000s) $138,399

City of Riverside

Customers Served 100,766
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 318,800
Purchased 2,215,900
Total 2,534,700
Total Revenues (000s) $232,809*
Operating Costs (000s) $201,728*
*Unaudited

City of Vernon

Customers Served 2,060
Power Generated and Purchased
(in Megawatt-Hours)
Self-Generated 0
Purchased 1,339,133
Total 1,339,133
Total Revenues (000s) $107,052
Operating Costs (000s) $92,071

Southern California Public Power Authority
225 S. Lake Avenue, Suite 1250
Pasadena, CA 91101
Tel: (626) 793-9364 • Fax: (626) 793-9461
Website: www.scppa.org

PINNACLE WEST CAPITAL CORPORATION

EVERY TIME
This Light Blinks

··· 2004 ANNUAL REPORT ···

Pinnacle West is a Phoenix-based company with consolidated assets of $9.9 billion and consolidated revenues of $2.9 billion. Through our subsidiaries, we generate, sell and deliver electricity and sell energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate projects.

STRATEGIC OBJECTIVES

- Focus on superior long-term total returns for shareholders
- Provide Arizona electricity customers with reliable energy at fair prices
- Capture growth opportunities in our electricity markets
- Actively manage our costs and business risks
- Maximize the long-term value of our assets
- Increase our resource portfolio consistent with our native load, cash flow and market conditions
- Work with regulators to achieve positive regulatory outcomes that benefit both customers and shareholders
- Maintain a disciplined focus on our long-term goals while remaining agile

...we spend another $100 on electric infrastructure, because every six times this light blinks Arizona gains a new resident and every 32 times this light blinks a resident builds a new home.

That's the relentless pace of Arizona's growth – and it's our job to power it. It's a job we take very seriously, every minute of every day. As for this blinking light, we're told it will stop blinking in about 120 days. By contrast, our company will continue to keep the lights on for our customers. Just as we have for the last 118 years.

Note: The "blinking light messages" in this Annual Report are based on an eight-hour day, 365 days a year, and the light is set to blink every four seconds. For example, in 2005 our company will spend about $300 million to enhance Arizona's electric infrastructure and prepare for growth. This computes to roughly $822,000 per day, and using an eight-hour day, a little over $100 every four seconds.

FINANCIAL HIGHLIGHTS

dollars in thousands, except per share amounts

	Year Ended December 31,			Growth Rate	
	2004	2003	2002	2004 vs 2003	2003 vs 2002
INCOME HIGHLIGHTS					
Operating revenues	$ 2,899,725	$ 2,759,494	$ 2,405,250	5.1%	14.7 %
Income from continuing operations	$ 235,218	$ 225,803	$ 236,563	4.2%	(4.5)%
Net income	$ 243,195	$ 240,579	$ 149,408	1.1%	61.0 %
BALANCE SHEET HIGHLIGHTS					
Total assets – year-end	$ 9,896,747	$ 9,519,042	$ 9,139,157	4.0%	4.2 %
Common stock equity – year-end	$ 2,950,196	$ 2,829,779	$ 2,686,153	4.3%	5.3 %
PER SHARE HIGHLIGHTS					
Earnings per share from continuing operations – diluted	$ 2.57	$ 2.47	$ 2.78	4.0%	(11.2)%
Net income – diluted	$ 2.66	$ 2.63	$ 1.76	1.1%	49.4 %
Indicated annual dividend – year-end	$ 1.90	$ 1.80	$ 1.70	5.6%	5.9 %
Book value per share – year-end	$ 32.14	$ 30.97	$ 29.40	3.8%	5.3 %
STOCK PERFORMANCE					
Stock price per share – year-end	$ 44.41	$ 40.02	$ 34.09		
Stock price appreciation	11.0%	17.4%	(18.5)%		
Total return	15.9%	23.1%	(14.8)%		
Market capitalization – year-end	$ 4,076,965	$ 3,657,025	$ 3,115,142	11.5%	17.4 %

Every time this light blinks, APS installs two more feet of wire to serve the increasing needs of our customers.

THAT TRANSLATES TO ABOUT

5,000,000 feet of wire a year.

IN 2004, APS CONTINUED TO WORK HARD TO IMPROVE ARIZONA'S ELECTRIC INFRASTRUCTURE AND KEEP UP WITH ITS RAPID GROWTH BY ADDING MORE THAN 900 MILES OF TRANSMISSION AND DISTRIBUTION WIRES. IF LAID FROM END TO END, THE WIRE WOULD STRETCH FROM PHOENIX TO DENVER.

TO OUR SHAREHOLDERS

CHAIRMAN'S LETTER

We may not need a blinking light to tell you how fast we're growing, but it does make the point, doesn't it?

Now that I've got your attention, I'll admit the Arizona growth story is not news. But our *re-accelerating* growth is. Customer growth re-accelerated last year to 3.7 percent, back to our five-year average after a slight dip in 2002 and 2003. And our five-year average growth of 3.7 percent is three times the industry average.

That re-acceleration *is* news because growth will continue and even accelerate more this year. That story – and why growth is good for shareholders *and* customers – is the focus of this year's report to our owners.

Managing Growth in 2004

Reaching agreement on our rate case with customer groups and other stakeholders marked a high point in 2004, but it was only one among many. It was a demanding year for employees, who managed record growth, worked safer than ever, added another to a string of "top producing power station" years at the Palo Verde Nuclear Generating Station and calmly and professionally resolved a once-in-a-career transmission event.

Palo Verde's 10-year average capacity factor of 89.5 percent exceeded the 10-year national average by more than five percentage points. That means, just looking at APS' 29-percent share of Palo Verde, we averaged over 500,000 more megawatt-hours of production per year than we would have achieved with merely average performance. And Palo Verde's three-year-average production cost of 1.35 cents per kilowatt-hour was 27 percent below the national average for nuclear units. Higher capacity factors and lower costs add up to considerable savings for customers and a sizable contribution to earnings.

For our shareholders, the results in 2004 were strong. We set ourselves apart with our eleventh consecutive annual dividend increase. Shareholders received a total return (stock price increase plus dividends) of 16 percent. Our stock performance, even in the face of re-regulation, nearly matched the strong utility industry.

Our customers continued to enjoy high reliability, exceptional service and lower prices. From 1996 through 2004, APS invested about $3.6 billion to expand generation and upgrade transmission and distribution systems. Over this same period, the number of customer outages dropped by a third and the average interruption decreased in duration by 44 percent.

Those numbers illustrate our ability to manage growth *and* improve service. In a testament to the dedication to service shared throughout our company, our customer satisfaction ratings remained outstanding. APS ranked in the top 10 percent nationally – and first among investor-owned utilities in the West – in overall customer satisfaction in both the latest J.D. Power and Associates residential and business customer surveys.

In 2004, our customers experienced a full year of prices that were lower than 20 years ago, and 44 percent lower on an inflation-adjusted basis. After a decade of price decreases which ended in 2003, nominal prices are 16 percent lower than they were in 1993. To produce these kinds of numbers, we've been innovative in finding ways to cut costs and increase efficiencies. Year after year, with a series of price decreases over the last decade, we improved performance while keeping our regulatory commitments.

Growth means constant attention to resource planning. We grew into – and now we're outgrowing – the chunks of base-load generation and transmission capacity we've added over the years. The good news hidden in those engineering realities is that, with cooperation from our regulators, we can accommodate growth with upgraded facilities and a faster pace of technological innovation.

Leveraging Growth for Greater Reliability and Environmental Quality

Our customer growth is not just compatible with high reliability and environmental quality – it will ultimately enhance both. A high rate of growth brings opportunities that a stagnant or declining customer base would not allow – opportunities for achieving new efficiencies and employing new technologies.

Opportunities to replace older equipment come faster because of our growth. At every opportunity we're leveraging growth to improve reliability with new and better technology and infrastructure. Ultimately, the result is greater flexibility, cost efficiency and reliability. Growth-generated enhancements will propel us further and faster toward our goal of becoming a model 21st century utility.

Growth also has advantages for creating a sustainable environment. With the support of our regulators, we are pursuing growth of solar power – a technology in which we are a national leader among utilities – and of biomass, wind and hydrogen as future alternative sources of power.

We know the challenges of growth. We're vigilant, but not intimidated. We have a skilled and experienced group of men and women who tackle the opportunities. Our employees demand more of themselves today in order to meet the needs of tomorrow. That's the attitude guiding us toward continuing improvement.

Clashing Visions, Growing Agendas

As we said in last year's Annual Report, we're becoming a new kind of integrated utility. This year, with our new regulatory platform, we're much closer to our goal: a utility meeting its customers' needs reliably and efficiently with vertically integrated resources in an evolving market.

That vision is becoming more common as it's evident that competition and regulation – or re-regulation – will continue to clash and coexist. Clearly, our company will continue to live in both worlds. We're a vertically integrated company, and that means our generation resources as well as our "wires" infrastructure will primarily earn a regulated return. Yet we plan to obtain over 1,000 megawatts from the competitive market in the next three years. And with the high availability factors of our recently completed gas units, we will sell into the wholesale market. That sounds like competition.

The Federal Energy Regulatory Commission (FERC) and many states, including Arizona, will continue to adopt new and sometimes discordant positions. It's our job to satisfy both sets of rules and succeed in both worlds. In reality, market and regulatory structures will be determined by many factors – core competencies of the utility, market robustness and liquidity, and the interplay of power, policy and politics among state regulators, Congress and the FERC. Until there is more clarity, we will continue to balance these evolving structures, maintaining flexibility to exceed customer and shareholder expectations.

Turning Growth into Shareholder Value

We're confident in our ability to continue long-term improvement in earnings and cash flow. To attract the capital we need to keep up with growth, we must continue to compensate investors for shouldering risk. That's also the key that unlocks our ability to continue improving reliability while protecting our natural environment. We won't diminish our obligation to secure Arizona's energy future for our customers or concede our commitment to a fair return for shareholders.

WE HAVE AN ENVIABLE TRACK RECORD OF CONVERTING GROWTH INTO SHAREHOLDER VALUE, AND WE WILL CONTINUE THAT VALUE CREATION IN THE FUTURE.

Growth is good news for investors because it drives revenue growth that, well managed, produces earnings growth. We're confident we can continue to capture the benefits of growth for investors in the form of greater overall profitability, improved cash flow and higher dividends.

We have an enviable track record of converting growth into shareholder value, and we will continue that value creation in the future. Our strategy to secure the benefits of customer growth for investors is built around four major elements: achieving regulatory collaboration, controlling operating and capital costs through operational excellence and risk management, etching a strong financial profile and embracing technology and innovation.

First, we will continue to work with regulators to refine our newly restructured regulatory platform. After avoiding the structural failures of California-style deregulation, we expanded our approach to competition and regulation. We reached agreement last year with major customer groups on a new regulatory platform, the main elements of which were endorsed in early March by an administrative law judge. As this report goes to press, we are awaiting approval by our Arizona regulators.

The new platform will remedy our most urgent regulatory issues: it consolidates our company by putting the Arizona plants built by Pinnacle West Energy, our unregulated generation subsidiary, into the APS rate base. There, the plants will earn a regulated return and provide valuable, reliable, cost-effective and environmentally suitable capacity for our customers. It provides for a fuel and purchased power adjustment clause, our first since 1989, and includes a 4.2 percent rate increase.

Perhaps most important, this long overdue restructured regulatory platform will give us the opportunity to look forward not backward. Instead of re-doing the regulatory decisions of the late 90s, we can anticipate the infrastructure and service needs of our customers. We are responsible for meeting our customers' needs. We've done it before and we will continue to do so.

Second, we will manage power costs and capacity needs with excellent operations of a broad resource base and effective risk management strategies. With our low-cost nuclear and coal units fully deployed and achieving high capacity factors, we are well positioned to supply economical power for our customers. The new gas

units at Redhawk, West Phoenix and Saguaro will enable a diverse energy supply mix of nuclear, coal and gas. As supplies tighten and spark spreads widen over the next few years, our gas units will allow us to capture opportunities in the wholesale market as well as supply our customers' needs.

We've controlled fuel and purchased power risk for years, and we will continue to do so. With a fuel adjustment clause added to our risk management tools, we will not reduce our intensity on minimizing cost. This fuel adjuster will become increasingly important as we achieve a more diverse generation fuel mix and as we contract for additional purchased power. Our new regulatory platform calls for a hiatus on building generation until 2015 – unless regulators agree the market is failing to provide adequate new capacity.

Third among our strategies for capturing the benefits of growth, we will achieve an improved financial profile. The new regulatory platform will provide some revenue boost. In addition, with the Arizona gas-fired units expected soon to be in the APS rate base, our corporate risk profile will be much lower, which will bolster our financial flexibility.

We've enhanced our cash flow over the last two years with asset sales, primarily by SunCor, our real estate subsidiary. As we've often said in the past about SunCor, we will maximize the value of our assets for shareholders over the long term with sales or purchases depending on opportunity and the economy. Years ago, we adopted a two-pronged financial strategy – maintaining an investment-grade rating on all corporate-level debt and targeting a steady pace of dividend increases. The former keeps our financing costs low – essential for a rapidly growing utility like APS – and the latter sets our financial profile apart from many other utilities.

Finally, innovation and further deployment of technology will help control our generation costs, but the potential for digital advances on the delivery side – the "wires" and customer service part – of our business is truly exciting. Technology will allow us to fully utilize our current assets and leverage our talented employee base. With computer software and digital intelligence facilitating and enhancing our operations, we will continue to provide better as well as more efficient customer service. In 1994, we served about

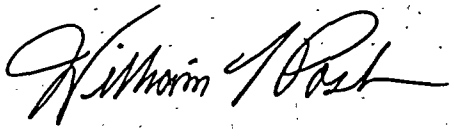
160 customers per employee. In 2004, we served 224 customers per employee while providing outstanding customer service, including more information, faster response to outages and higher reliability. Over the next decade, we expect to see equal or greater productivity gains and continuing service enhancements.

Over the long term, despite 10 years of regulatory uncertainty, market blowups in California and rate decreases in Arizona, we've generated a positive earnings and cash flow trend. With historic deregulation tremors behind us, we look forward to a more stable regulatory environment, a more robust wholesale power market, a better economy – and a resumption of earnings growth.

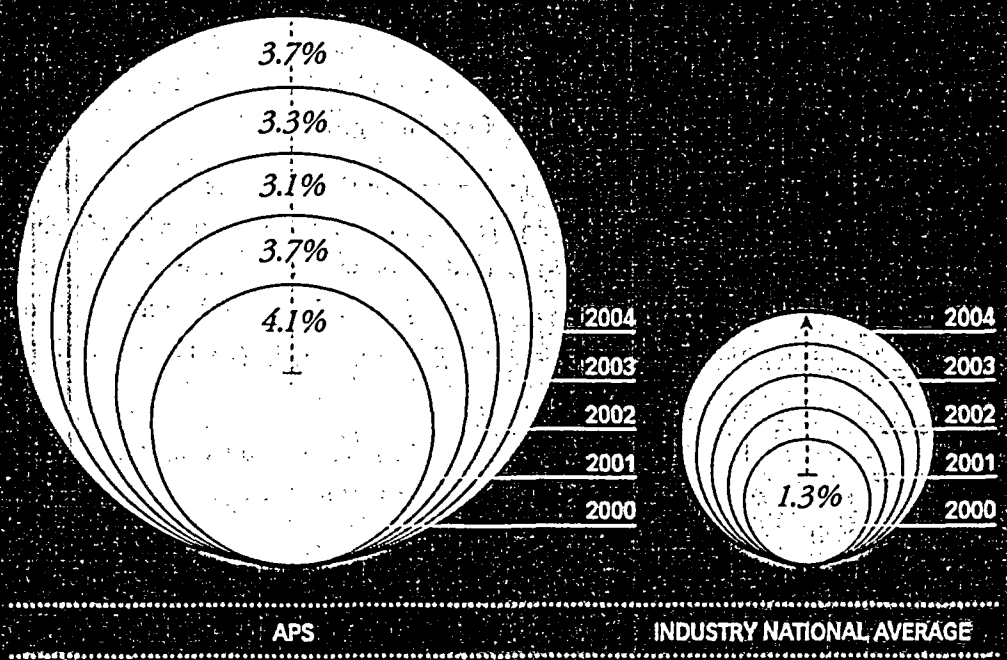
The past offers strong evidence of our ability to manage growth for the benefit of investors, but the earnings blip and dip from power marketing over the last few years may disguise the underlying stability of our core regulated utility business. Every year over the last 10 years, with the exception of the recession year 2001, our electricity sales growth exceeded both the Arizona population growth and our customer growth rates. The regulated core business gave us solid earnings and now it will drive future earnings growth.

What makes this all possible?

The answer is simple – our people. Each day, they come to the job ready to work hard, solve challenges and deliver unmatched service to our customers. They are the reasons we have succeeded for 118 years. They are the reasons we will continue to succeed in the future.



WILLIAM J. POST
Chairman



APS CUSTOMER GROWTH

Our accelerating customer growth continues at a pace three times the industry average.

Every time this light blinks, APS customers increase their peak energy demand by 130 watts.

THAT TRANSLATES TO ABOUT

350,000,000 watts a year.

IN 2005, THE PEAK ENERGY DEMAND OF OUR CUSTOMERS IS PROJECTED TO INCREASE 350 MILLION WATTS OVER 2004. THIS INCREASE REPRESENTS ENOUGH ENERGY TO SERVE THE EQUIVALENT OF 100,000 ARIZONA HOMES.

CREATING VALUE

Pinnacle West stock outperformed the S&P 500 Index again in 2004. Pinnacle West's total return for 2004 was 16 percent, compared to 10.8 percent for the S&P 500.

ACCOMPLISHMENTS

- We serve 225 customers for every employee, compared with fewer than 200 customers per employee in 1999 – a better than 11 percent efficiency increase.
- APS has significantly and steadily improved system reliability. In 1996, the average customer experienced 1.5 outages in a year. In 2004, that number decreased to about one outage – a 33 percent improvement.
- In both the latest J.D. Power Residential and Business Customer Satisfaction Surveys, APS earned the second highest ranking among utilities in the West in overall customer satisfaction, and ranked first among investor-owned utilities in the region.
- Improved efficiency and streamlined processes allowed APS to reduce customer electricity prices by about 16 percent since 1993.
- Sixteen APS line trucks and 40 crew members trekked across the country this summer to lend a much needed hand to overwhelmed Florida electric crews restoring power after the state's devastating hurricane season.

MANAGING GROWTH

APS' customer base grew 3.7 percent in 2004 – a rate three times the national average.

ACCOMPLISHMENTS

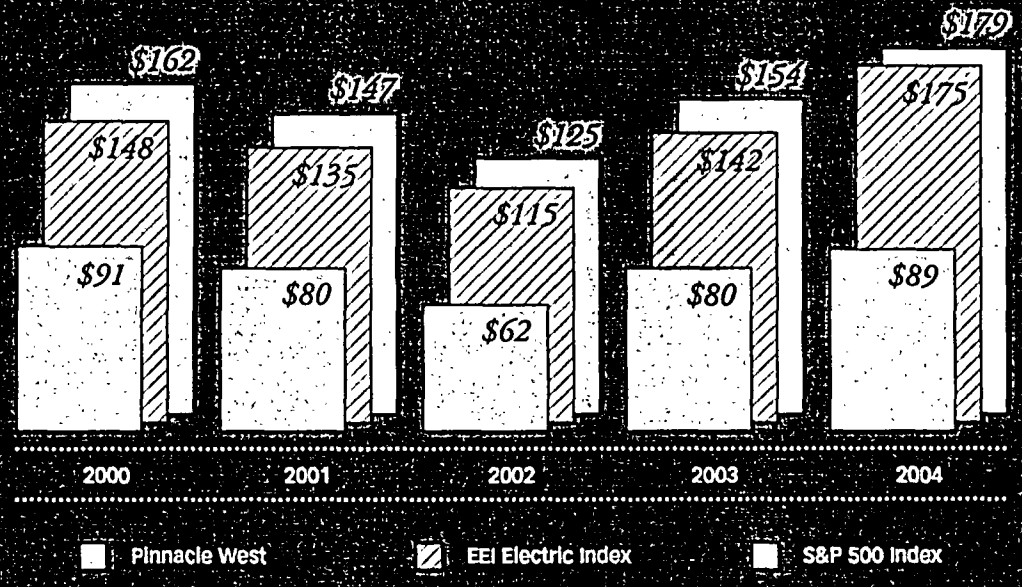
- In early 2005, APS surpassed one million customers for the first time in our company's 118-year history. This includes more than 300,000 customers added in the last decade alone.
- APS installed nearly 42,000 business and residential meters in 2004 – a new company record.
- To keep up with Arizona's growth, APS completed 75 substation improvement projects, five new substations and four new temporary substations in 2004.
- Our company continues to be a leader in renewable technology. In addition to expanding and developing more solar technology, we are exploring new renewable technologies including biogas, wind and biomass.
- Our call center fielded a record 4.5 million calls in 2004 and met its goal of answering calls in a timely manner.
- APS Energy Services has steadily grown its energy efficiency and district cooling and heating services in the Western region.

ACHIEVING EXCELLENCE

In 2004, the Palo Verde Nuclear Generating Station marked its 13th consecutive year as the nation's largest power producer of any kind.

ACCOMPLISHMENTS

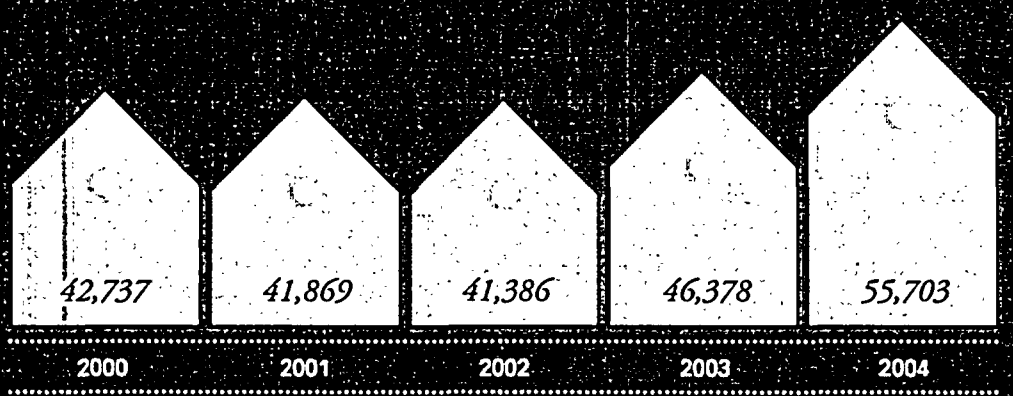
- In 2004, our company reduced our number of preventable recordable injuries, breaking the previous record low and setting a new safety performance standard.
- In the last 20 years, our West Phoenix, Ocotillo and Yucca Power Plants have zero combined lost-time accidents.
- SunCor, our real estate development company, produced significant earnings again this year – contributing $45 million to the bottom line.
- For the third time in as many studies, we earned the top rating – AAA – from Innovest Strategic Value Advisors, for our environmental performance.
- In 2004, Innovest Strategic Advisors also ranked Pinnacle West as the top utility in its Intangible Value Assessment (IVA). The IVA is designed to uncover investment value potential by measuring companies in areas such as corporate governance, community outreach, labor relations and regulatory relations.



Value of $100 invested on December 31, 1999, with dividends reinvested
(all dollar amounts as of year-end)

PINNACLE WEST STOCK PERFORMANCE COMPARISON

Pinnacle West stock has proven to be a sound investment, outpacing the S&P 500 Index and EEI Electric Index over the last five years.



PHOENIX AREA RESIDENTIAL BUILDING PERMITS

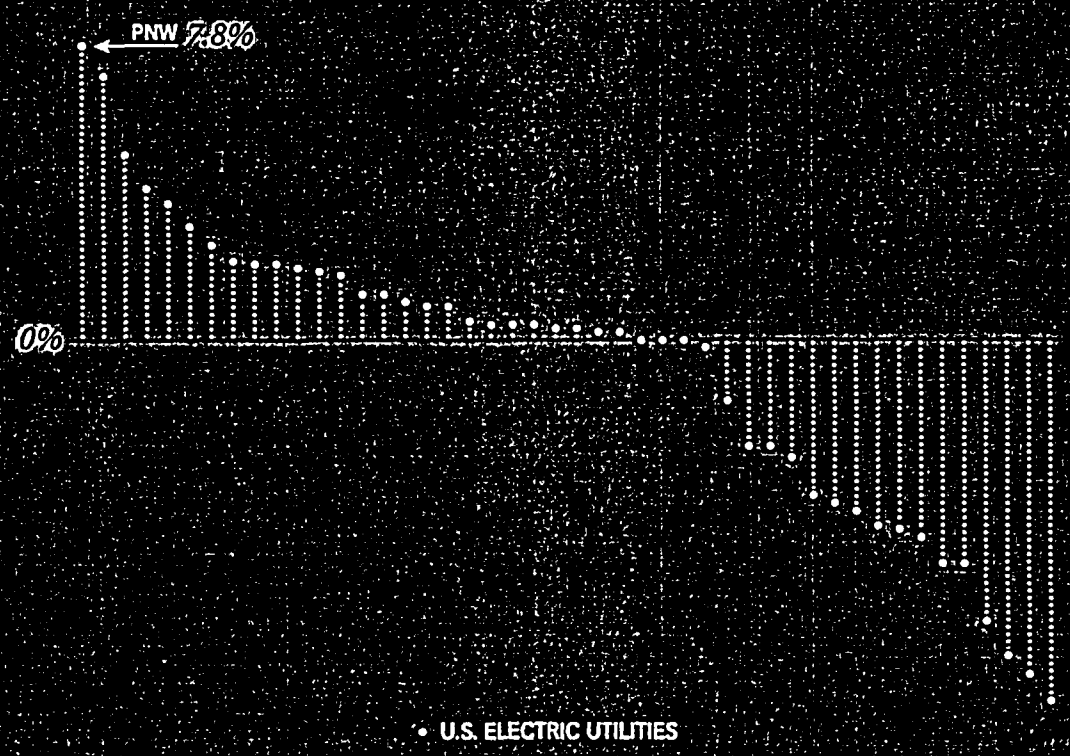
Phoenix – now the nation's fifth largest city – is experiencing rapid expansion in both population and new homes.

Every time this light blinks, another 45 square feet of a new home is built in the Phoenix area.

THAT TRANSLATES TO ABOUT

120,000,000 square feet a year.

IN 2004, THE PHOENIX AREA CONTINUED TO EXPAND, WITH ABOUT 120 MILLION SQUARE FEET OF NEW HOMES. THIS IS THE EQUIVALENT OF ADDING THE SQUARE FOOTAGE OF MORE THAN 50 EMPIRE STATE BUILDINGS EACH YEAR.



U.S. ELECTRIC UTILITIES AVERAGE
ANNUAL DIVIDEND GROWTH 1995 TO 2004

We've earned the top spot among all U.S. electric utilities in dividend growth over the last decade.

2004

CONSOLIDATED
Financial Information

SELECTED CONSOLIDATED FINANCIAL DATA *(dollars in thousands, except per share amounts)*

	2004	2003	2002	2001	2000
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment	$ 2,035,247	$ 1,978,075	$ 1,890,391	$ 1,984,305	$ 2,538,752
Marketing and trading segment	461,870	391,886	286,879	469,784	418,532
Real estate segment	359,792	361,604	201,081	168,908	158,365
Other revenues (a)	42,816	27,929	26,899	11,771	3,873
Total operating revenues	$ 2,899,725	$ 2,759,494	$ 2,405,250	$ 2,634,768	$ 3,119,522
Income from continuing operations	235,218	225,803	236,563	327,367	302,332
Discontinued operations – net of income taxes (b)	7,977	14,776	(21,410)	–	–
Cumulative effect of change in accounting – net of income taxes (c)(d)	–	–	(65,745)	(15,201)	–
Net income	$ 243,195	$ 240,579	$ 149,408	$ 312,166	$ 302,332
COMMON STOCK DATA					
Book value per share – year-end	$ 32.14	$ 30.97	$ 29.40	$ 29.46	$ 28.09
Earnings (loss) per weighted average common share outstanding:					
Continuing operations – basic	$ 2.57	$ 2.47	$ 2.79	$ 3.86	$ 3.57
Discontinued operations (b)	0.09	0.17	(0.26)	–	–
Cumulative effect of change in accounting (c)(d)	–	–	(0.77)	(0.18)	–
Net income – basic	$ 2.66	$ 2.64	$ 1.76	$ 3.68	$ 3.57
Continuing operations – diluted	$ 2.57	$ 2.47	$ 2.78	$ 3.85	$ 3.56
Net income – diluted	$ 2.66	$ 2.63	$ 1.76	$ 3.68	$ 3.56
Dividends declared per share	$ 1.825	$ 1.725	$ 1.625	$ 1.525	$ 1.425
Indicated annual dividend rate per share – year end	$ 1.90	$ 1.80	$ 1.70	$ 1.60	$ 1.50
Weighted-average common shares outstanding – basic	91,396,904	91,264,696	84,902,946	84,717,649	84,732,544
Weighted-average common shares outstanding – diluted	91,532,473	91,405,134	84,963,921	84,930,140	84,935,282
BALANCE SHEET DATA					
Total assets	$ 9,896,747	$ 9,519,042	$ 9,139,157	$ 8,529,124	$ 7,697,558
Liabilities and equity:					
Long-term debt less current maturities	$ 2,584,985	$ 2,616,585	$ 2,743,741	$ 2,673,078	$ 1,955,083
Other liabilities	4,361,566	4,072,678	3,709,263	3,356,723	3,359,761
Total liabilities	6,946,551	6,689,263	6,453,004	6,029,801	5,314,844
Common stock equity	2,950,196	2,829,779	2,686,153	2,499,323	2,382,714
Total liabilities and equity	$ 9,896,747	$ 9,519,042	$ 9,139,157	$ 8,529,124	$ 7,697,558

(a) Includes reclassifications of revenues in 2003 and 2002 related to the discontinued operations of NAC. See Note 22 of Notes to Pinnacle West's Consolidated Financial Statements.
(b) NAC and real estate discontinued operations. See Note 22 of Notes to Pinnacle West's Consolidated Financial Statements.
(c) Change in accounting standards related to energy trading activities in 2002. See Note 18 of Notes to Pinnacle West's Consolidated Financial Statements.
(d) Change in accounting standards related to derivatives in 2001.

QUARTERLY STOCK PRICES AND DIVIDENDS PAID PER SHARE *Stock Symbol:* PNW

2004	High	Low	Close	Dividends Per Share
1st Quarter	$ 40.81	$ 36.90	$ 39.35	$ 0.450
2nd Quarter	41.50	36.30	40.39	0.450
3rd Quarter	42.99	39.63	41.50	0.450
4th Quarter	45.84	41.61	44.41	0.475

2003	High	Low	Close	Dividends Per Share
1st Quarter	$ 37.13	$ 28.34	$ 33.24	$ 0.425
2nd Quarter	39.59	31.35	37.45	0.425
3rd Quarter	38.03	32.87	35.50	0.425
4th Quarter	40.48	34.91	40.02	0.450

GLOSSARY

ACC – Arizona Corporation Commission
ADEQ – Arizona Department of Environmental Quality
AFUDC – allowance for funds used during construction
ALJ – Administrative Law Judge
APS – Arizona Public Service Company, a subsidiary of the Company
APS ENERGY SERVICES – APS Energy Services Company, Inc., a subsidiary of the Company
CC&N – Certificate of Convenience and Necessity
CHOLLA – Cholla Power Plant
CLEAN AIR ACT – Clean Air Act, as amended
COMPANY – Pinnacle West Capital Corporation
DOE – United States Department of Energy
EITF – FASB's Emerging Issues Task Force
EL DORADO – El Dorado Investment Company, a subsidiary of the Company
EPA – United States Environmental Protection Agency
ERMC – Energy Risk Management Committee
FASB – Financial Accounting Standards Board
FERC – United States Federal Energy Regulatory Commission
FIN – FASB Interpretation
FINANCING ORDER – ACC Order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003
FOUR CORNERS – Four Corners Power Plant
FSP – FASB Staff Position
GAAP – accounting principles generally accepted in the United States of America
IRS – United States Internal Revenue Service
ISO – California Independent System Operator
KWH – kilowatt-hour, one thousand watts per hour
MOODY'S – Moody's Investors Service
MW – megawatt, one million watts
MWH – megawatt-hours, one million watts per hour
NAC – collectively, NAC Holding Inc. and NAC International Inc., subsidiaries of El Dorado that were sold in November 2004
NATIVE LOAD – retail and wholesale sales supplied under traditional cost-based rate regulation
1999 SETTLEMENT AGREEMENT – comprehensive settlement agreement related to the implementation of retail electric competition
NRC – United States Nuclear Regulatory Commission
NUCLEAR WASTE ACT – Nuclear Waste Policy Act of 1982, as amended
OCI – other comprehensive income
PALO VERDE – Palo Verde Nuclear Generating Station, also known as ANPP
PINNACLE WEST – Pinnacle West Capital Corporation, the Company
PINNACLE WEST ENERGY – Pinnacle West Energy Corporation, a subsidiary of the Company
PPL SUNDANCE – PPL Sundance Energy, LLC
PSA – power supply adjuster
PWEC DEDICATED ASSETS – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3
PX – California Power Exchange
RFP – request for proposals
RULES – ACC retail electric competition rules
SALT RIVER PROJECT – Salt River Project Agricultural Improvement and Power District
SEC – United States Securities and Exchange Commission
SFAS – Statement of Financial Accounting Standards
SNWA – Southern Nevada Water Authority
SPARK SPREAD – excess of market power price over market gas price at a specific location
SPE – special-purpose entity
STANDARD & POOR'S – Standard & Poor's Corporation
SUNCOR – SunCor Development Company, a subsidiary of the Company
SUNDANCE PLANT – PPL Sundance's 450-megawatt generating facility located approximately 55 miles southeast of Phoenix, Arizona
T&D – transmission and distribution
TRACK A ORDER – ACC order dated September 10, 2002 regarding generation asset transfers and related issues
TRACK B ORDER – ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities
TRADING – energy-related activities entered into with the objective of generating profits on changes in market prices
2004 SETTLEMENT AGREEMENT – an agreement proposing terms under which APS' general rate case would be settled
VIE – variable interest entity

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

INTRODUCTION

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

OVERVIEW

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

Pinnacle West Energy is our unregulated generation subsidiary. We formed Pinnacle West Energy in 1999 as a result of the ACC's requirement that APS transfer all of its competitive assets and services to an affiliate or to a third party by the end of 2002. We planned to transfer APS' generation assets to Pinnacle West Energy. Additionally, Pinnacle West Energy constructed several power plants to meet growing energy needs (1,790 MW in Arizona and 570 MW in Nevada). In September 2002, the ACC issued the Track A Order, which prohibited APS from transferring its generation assets to Pinnacle West Energy. As a result of the Track A Order, APS, through its general rate case currently pending before the ACC, is seeking to transfer the plants built by Pinnacle West Energy in Arizona to APS to unite the Arizona generation under one common owner, as originally intended. We refer to these plants as the PWEC Dedicated Assets.

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

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

El Dorado, our investment subsidiary, sold its investment in NAC on November 18, 2004, which resulted in a pretax gain of $4 million and the classification of NAC as discontinued operations in 2004. In addition, the year ended December 31, 2004 includes a $35 million gain ($21 million after tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2004 represented the thirteenth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and customer satisfaction while expanding our transmission and distribution system to meet growth and sustain reliability. We plan to expand long-term resources to meet our retail customers' growing electricity needs.

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, on August 18, 2004, a substantial majority of the parties to the rate case, including APS, the ACC staff, the Arizona Residential Utility Consumer Office, other customer and advocacy groups, and merchant power plant intervenors entered into the 2004 Settlement Agreement, which proposes terms under which the rate case would be settled. Neither Pinnacle West nor APS is able to predict whether the ACC will approve the 2004 Settlement Agreement as proposed.

Other factors affecting our past and future financial results include customer growth; purchased power and fuel costs; operations and maintenance expenses, including those relating to plant and transmission outages; weather variations; depreciation and amortization expenses, which are affected by net additions to utility plant and other property and changes in regulatory asset amortization; and the performance of our subsidiaries.

EARNINGS CONTRIBUTIONS AND BUSINESS SEGMENTS

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

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

The following table summarizes income from continuing operations by segment and net income for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Regulated electricity (a)	$ 151	$ 170	$ 170
Marketing and trading	18	9	58
Real estate	40	45	10
Other (b)	26	2	(1)
Income from continuing operations	235	226	237
Real estate discontinued operations – net of income taxes (c)	4	10	9
Other discontinued operations – net of income taxes (c)	4	5	(31)
Cumulative effect of change in accounting – net of income taxes (d)	–	–	(66)
Net income	$ 243	$ 241	$ 149

(a) In 2002, Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately $30 million after income taxes ($49 million pretax).
(b) The year ended 2004 includes a $35 million gain ($21 million after-tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.
(c) Discontinued operations relate to NAC and real estate. See Note 22.
(d) Marketing and trading segment change in accounting for trading activities upon adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.

See Note 17 for additional financial information regarding our business segments.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. "Gross margin" is a "non-GAAP financial measure," as defined in accordance with SEC rules. "Operating margin" (a GAAP financial measure) plus "other operating expenses," as disclosed in Note 17, is equal to gross margin. We view gross margin as an important performance measure of the core profitability of our operations. This measure is a key component of our internal financial reporting and is used by our management in analyzing our business segments. We believe that investors benefit from having access to the same financial measures that our management uses. In addition, we have reclassified certain prior period amounts to conform to our current period presentation.

2004 Compared with 2003

Our consolidated net income for the twelve months ended December 31, 2004 was $243 million compared with $241 million for the prior-year period. The $2 million increase in the period-to-period comparison reflected the following changes in earnings by segment:

- Regulated Electricity Segment – Net income decreased approximately $19 million primarily due to higher costs (primarily interest expense, depreciation, operation and maintenance costs and property taxes, net of gross margin contributions) related to a new power plant placed in service in mid-2003; increased operations and maintenance costs primarily related to customer service and personnel costs; lower income tax credits; higher depreciation related to delivery and other assets; the effects of milder weather on retail sales; and a retail electricity rate decrease in mid-2003. These negative factors were partially offset by lower regulatory asset amortization, and higher retail sales volumes due to customer growth and usage.

- Marketing and Trading Segment – Net income increased approximately $9 million primarily due to higher forward and realized prices for wholesale electricity partially offset by lower margins in California by APS Energy Services and increased costs related to a new power plant placed in service in mid-2004.
- Real Estate Segment – Net income decreased approximately $11 million primarily due to the 2003 gain on the sale of SunCor's water utility company, which was reported as discontinued operations (see Note 22), and decreased asset sales partially offset by increased land sales.
- Other Segment – Net income increased approximately $23 million primarily due to a $21 million after-tax gain related to the sale of El Dorado's limited partnership interest in the Phoenix Suns.

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

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Higher retail sales volumes due to customer growth, excluding weather effects	$ 43	$ 26
Lower replacement power costs due to fewer unplanned outages	6	4
Effects of weather on retail sales	(17)	(10)
Retail electricity price reduction effective July 1, 2003	(13)	(8)
Increased purchased power and fuel costs due to higher fuel and power prices	(4)	(2)
Miscellaneous factors, net	(8)	(6)
Net increase in regulated electricity segment gross margin	7	4
Marketing and trading segment gross margin:		
Higher mark-to-market gains for contracts for future delivery due to higher forward prices for wholesale electricity	28	17
Higher realized margins on energy trading primarily due to higher electricity prices	18	11
Increase in generation sales other than Native Load primarily due to higher sales volumes and higher unit volumes	9	5
Lower unit margins and lower competitive retail sales volumes in California by APS Energy Services	(22)	(13)
Net increase in marketing and trading segment gross margin	33	20
Net increase in gross margin for regulated electricity and marketing and trading segments	40	24
Lower real estate segment contributions primarily due to decreased asset sales, a portion of which was recorded in other income in the prior period, partially offset by higher land sales (See Note 22)	(7)	(5)
Higher other income due to the sale of El Dorado's limited partnership interest in the Phoenix Suns	35	21
Higher operations and maintenance expense primarily related to customer service costs, new power plants in service and personnel costs	(48)	(29)
Interest expense net of capitalized financing costs, decreases (increases):		
New power plants in service	(23)	(14)
Lower other debt balances and rates partially offset by increased utility plant in service	9	5
Depreciation and amortization decreases (increases):		
Lower regulatory asset amortization	68	41
New power plants in service	(14)	(8)
Increased delivery and other assets	(20)	(12)
Higher property taxes due to increased plant in service	(12)	(7)
Lower income tax credits	–	(17)
Miscellaneous items, net	8	10
Net increase in income from continuing operations	$ 36	9
Discontinued operations (primarily real estate segment, see Note 22)		(7)
Net increase in net income		$ 2

The increase in net costs (primarily interest expense, depreciation and operations and maintenance expense, net of gross margin contributions) related to new power plants placed in service in mid-2003 and mid-2004 by Pinnacle West Energy totaled approximately $26 million after income taxes in the twelve months ended December 31, 2004 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $57 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily as a result of:

- a $101 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $42 million decrease in retail revenues related to milder weather;
- a $13 million decrease in retail revenues related to a reduction in retail electricity prices; and
- an $11 million increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $70 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily as a result of:

- a $47 million increase from generation sales other than Native Load primarily due to higher wholesale market prices and higher sales volumes, including sales from the new power plants in service;
- $28 million in higher mark-to-market gains for future-period deliveries primarily as a result of higher forward prices for wholesale electricity;
- $20 million of higher energy trading revenues on realized sales of electricity primarily due to higher electricity prices; and
- a $25 million decrease from lower competitive retail sales volumes in California by APS Energy Services.

Other Revenues

Other revenues were $15 million higher for the twelve months ended December 31, 2004 compared with the prior-year period primarily due to higher non-commodity revenues at APS Energy Services.

2003 Compared with 2002

Our consolidated net income for the year ended December 31, 2003 was $241 million compared with $149 million for the prior year. The 2003 net income included $15 million of after-tax income from discontinued operations related to NAC and SunCor. The 2002 net income included a $21 million after-tax loss from discontinued operations related to NAC and SunCor (see Note 22). The 2002 net income also included a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities due to the adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (see Note 18). Excluding the discontinued operations and the accounting change, the $11 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations was flat when comparing the two years, due to offsetting factors. Net income in 2003 was negatively impacted by higher purchased power and fuel costs resulting from higher prices for hedged gas and purchased power; higher costs related to new power plants, net of purchased power savings; higher replacement power costs from plant outages due to higher market prices and more unplanned outages (Cholla Unit 3 experienced an unplanned outage from August 3, 2003 through November, 2003 and Units 1 and 2 of the Redhawk Power Plant were substantially restricted for almost one-half of the fourth quarter to correct an equipment design defect); higher operations and maintenance costs related to increased pension and other benefits; two retail electricity price reductions; and higher depreciation expense related to increased delivery and other assets. These negative factors were offset by higher retail sales primarily due to customer growth and favorable weather; the absence of the 2002 write-off of Redhawk Units 3 and 4; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization; tax credits and favorable income tax adjustments related to prior years resolved in 2003; and higher income related to APS' return to the AFUDC method of capitalizing construction finance costs.

- Marketing and Trading Segment – Income from continuing operations decreased approximately $49 million primarily due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States.

- Real Estate Segment – Income from continuing operations improved approximately $35 million primarily due to increased asset, land and home sales.

- Other Segment – Income from continuing operations increased approximately $3 million primarily due to El Dorado Investment losses recognized in 2002.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2003 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	$ (60)	$ (36)
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(47)	(28)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(27)	(16)
Higher retail sales volumes due to customer growth, excluding weather effects	48	29
Decreased purchased power costs due to new power plants in service	16	10
Effects of weather on retail sales	13	8
Miscellaneous factors, net	5	2
Net decrease in regulated electricity segment gross margin	(52)	(31)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity and deteriorating counterparty credit	(59)	(35)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(32)	(19)
Higher margin related to structured contracts originated in prior years	13	7
Decrease in generation sales other than Native Load primarily due to lower unit margins partially offset by higher sales volumes, including sales from new power plants in service	(7)	(4)
Net decrease in marketing and trading segment gross margin	(85)	(51)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(137)	(82)
Higher income primarily related to El Dorado Investment losses recognized in 2002	8	5
Higher real estate segment contribution primarily due to higher asset, land and home sales	58	36
Operations and maintenance expense decreases (increases):		
Write-off of Redhawk Units 3 and 4 in 2002	47	28
Severance costs recorded in 2002	36	21
Increased pension and other benefit costs	(28)	(17)
Costs for new power plants in service	(20)	(12)
Net other items	1	1
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(26)	(16)
Depreciation and amortization decreases (increases):		
New power plants in service	(19)	(11)
Increased delivery and other assets	(22)	(13)
Decreased regulatory asset amortization	29	17
APS' return to the AFUDC method of capitalizing construction finance costs	8	11
Miscellaneous items, net	5	4
Tax credits and favorable income tax adjustments related to prior years resolved in 2003	–	17
Net decrease in income from continuing operations	$ (60)	(11)
Discontinued operations (primarily NAC, see Note 22)		37
Increase due to 2002 cumulative effect of a change in accounting for trading activities		66
Net increase in net income		$ 92

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $30 million after income taxes in the year ended December 31, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $88 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- an $85 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $21 million increase in retail revenues related to weather;
- a $6 million increase related to traditional wholesale sales as a result of higher prices and higher sales volumes;
- a $27 million decrease in retail revenues related to two reductions in retail electricity prices; and
- a $3 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $105 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- $74 million of higher revenues related to the adoption of EITF 02-3 in the fourth quarter of 2002, primarily due to structured contracts that were reported gross in the current period and net in most of the prior period;
- a $69 million increase from higher competitive retail sales in California by APS Energy Services;
- a $38 million increase from generation sales other than Native Load primarily due to higher prices and sales volumes, including sales from new power plants in service;
- $59 million in lower mark-to-market gains for future-period deliveries primarily as a result of lower market liquidity and lower price volatility; and
- $17 million of lower realized wholesale revenues primarily due to lower unit margins on trading activities that are reported on a net basis.

Real Estate Segment Revenues

Real estate segment revenues were $161 million higher in the year ended December 31, 2003 compared with the prior year primarily as a result of increased asset, land and home sales related to SunCor's effort to accelerate asset sales.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2004 and estimated capital expenditures for the next three years (dollars in millions):

	Actual	Estimated		
	2004	2005	2006	2007
APS				
Delivery	$ 342	$ 390	$ 395	$ 440
Generation (a)(b)	113	352	158	195
Other (c)	29	30	7	6
Subtotal	484	772	560	641
Pinnacle West Energy (a)	31	7	5	2
SunCor (d)	81	114	61	63
Other	2	8	7	4
Total	$ 598	$ 901	$ 633	$ 710

(a) As discussed in Note 3 under "APS General Rate Case; 2004 Settlement Agreement," as part of its general rate case, APS has requested rate base treatment of the PWEC Dedicated Assets. The estimated capital expenditures related to the PWEC Dedicated Assets are reflected in APS for the years 2005, 2006 and 2007.

(b) The estimate for 2005 includes about $190 million for acquisition of the Sundance Plant. See "Request for Proposals and Asset Purchase Agreement" in Note 3 for a discussion of the asset purchase agreement between APS and PPL Sundance.

(c) Primarily information systems and facilities projects.

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

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. Major transmission projects are driven by strong regional customer growth.

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

Replacement of the steam generators in Palo Verde Unit 2 was completed during the fall outage of 2003 at a cost to APS of approximately $70 million. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. These generators will be installed in Unit 1 (scheduled completion in the fall of 2005) and Unit 3 (scheduled completion in the fall of 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately $140 million, which will be spent through 2008. In 2005 through 2007, approximately $95 million of the costs for steam generator replacements at Units 1 and 3 are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

The following table summarizes Pinnacle West's consolidated contractual requirements as of December 31, 2004 (dollars in millions):

	2005	2006-2007	2008-2009	Thereafter	TOTAL
Long-term debt payments, including interest (a):					
APS	$ 577	$ 503	$ 206	$ 2,746	$ 4,032
Pinnacle West	189	305	–	–	494
SunCor	2	9	6	–	17
Total long-term debt payments, including interest	768	817	212	2,746	4,543
Short-term debt payments, including interest (b)	72	–	–	–	72
Capital lease payments	2	3	2	3	10
Operating lease payments	73	139	132	368	712
Minimum pension funding requirement (c)	50	–	–	–	50
Purchase power and fuel commitments (d)	187	171	134	363	855
Purchase obligations (e)	272	16	–	68	356
Nuclear decommissioning funding requirements	11	22	22	146	201
Total contractual commitments	$ 1,435	$ 1,168	$ 502	$ 3,694	$ 6,799

(a) The long-term debt matures at various dates through 2034 and bears interest principally at fixed rates. Interest on variable-rate long-term debt is determined by using the rates at December 31, 2004.
(b) The short-term debt matures within twelve months. The weighted-average interest rate used to determine interest payments on the short-term debt was 4.21% at December 31, 2004.
(c) Future pension contributions are not determinable for time periods after 2005.
(d) Our purchase power and fuel commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).
(e) These contractual obligations include commitments for capital expenditures and other obligations. Obligations for 2005 include about $190 million for acquisition of the Sundance Plant (see Note 3).

Off-Balance Sheet Arrangements

In 1986, APS entered into agreements with three separate VIE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. We are not the primary beneficiary of the Palo Verde VIEs and, accordingly, do not consolidate them.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which,

If appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2004, APS would have been required to assume approximately $250 million of debt and pay the equity participants approximately $192 million.

In the first quarter of 2004, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities" for all non-SPE contractual arrangements. SunCor has certain land development arrangements that are required to be consolidated under FIN No. 46R. The assets and non-controlling interests reflected in our Consolidated Balance Sheets related to these arrangements were approximately $34 million at December 31, 2004.

Guarantees and Letters of Credit

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Consolidated Balance Sheets with respect to these obligations. We generally provide indemnifications related to liabilities arising from or related to certain of our agreements, with limited exceptions depending on the particular agreement. See Note 21 for additional information regarding guarantees and letters of credit.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 15, 2005 are shown below and are considered to be "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase those companies' cost of and access to capital. It may also require additional collateral related to certain derivative instruments (see Note 18).

	Moody's	Standard & Poor's
PINNACLE WEST		
Senior unsecured	Baa2	BBB-
Commercial paper	P-2	A-2
Outlook	Negative	Negative
APS		
Senior unsecured	Baa1	BBB
Secured lease obligation bonds	Baa2	BBB
Commercial paper	P-2	A-2
Outlook	Negative	Negative

APS no longer has any senior secured debt. See "Capital Needs and Resources – By Company – APS" below for a discussion of the termination of APS' mortgage and deed of trust.

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet these and other significant covenant requirements. These covenants require that the ratio of debt to total capitalization cannot exceed 65% for the Company and for APS. At December 31, 2004, the ratio was approximately 53% for Pinnacle West and 54% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2004 results, the coverages were approximately 4 times for the Company and 4 times for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in financial condition or financial prospects, except that Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings equal to outstanding commercial paper amounts.

See Note 6 for further discussions.

Capital Needs and Resources by Company

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; interest payments and optional and mandatory repayments of principal on our long-term debt (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments). On October 20, 2004, our Board of Directors increased the common stock dividend to an indicated annual rate of $1.90 per share from $1.80 per share, effective with the December 1, 2004 dividend payment. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2002 through 2004, total dividends from APS were $510 million and total cash distributions from SunCor were $206 million. For the year ended December 31, 2004, dividends from APS were approximately $170 million and distributions from SunCor were approximately $85 million. We expect SunCor to make cash distributions to the parent company of approximately $80 to $100 million in 2005 based on anticipated asset sales activities. As discussed in Note 3 under "ACC Financing Orders," APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the Financing Order, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At December 31, 2004, APS' common equity ratio as defined was approximately 45%.

On February 2, 2004, we used proceeds from the $165 million Floating Rate Notes issued on November 12, 2003 and short-term borrowings to pay down the maturing $215 million 4.5% Senior Notes due 2004.

At December 31, 2004, the parent company's outstanding long-term debt, including current maturities, was $468 million. In October 2004, we replaced two separate revolving credit facilities (with collective borrowing capacity of $275 million) with a $300 million revolving credit facility that terminates in October 2007. This line of credit is available to support the issuance of up to $250 million in commercial paper or to be used as bank borrowings, including up to $100 million for issuances of letters of credit. At December 31, 2004, we had no commercial paper or short-term borrowings outstanding. We ended 2004 in an invested position.

Pinnacle West sponsors a qualified pension plan for the employees of Pinnacle West and our subsidiaries. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We contributed $35 million in 2004, $46 million in 2003, $27 million in 2002, $44 million in 2001 and $24 million in 2000. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 92% of the total funding amounts described above. The assets in the plan are comprised of common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions. The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately $50 million. The expected contribution to our other postretirement benefit plans in 2005 is estimated to be approximately $40 million.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "ACC Financing Order" in Note 3 for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

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

On February 15, 2004, $125 million of APS' 5.875% notes due 2004 were redeemed at maturity and on March 1, 2004, $80 million of APS' First Mortgage Bonds, 6.625% Series due 2004 were redeemed at maturity. APS used cash from operations and short-term debt to redeem the maturing debt.

On March 31, 2004, Navajo County, Arizona Pollution Control Corporation issued $166 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2034. The bonds were issued to refinance $166 million of outstanding pollution control bonds. The refinanced bonds were all $25 million of the Navajo 5.50% bonds due 2028 and $141 million of the Navajo 5.875% bonds due 2028. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Navajo County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Consolidated Balance Sheets. See Note 6.

Also on March 31, 2004, Coconino County, Arizona Pollution Control Corporation issued $13 million of variable interest rate pollution control bonds, 2004 Series A, due 2034. The bonds were issued to refinance $13 million of outstanding pollution control bonds. The refinanced bonds were $13 million of the Coconino 5.875% bonds due 2028. The Series A bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Coconino County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Consolidated Balance Sheets. See Note 6.

In May 2004, APS renewed its $250 million revolving credit facility, while increasing its size to $325 million and extending its term to three years. The revolver provides liquidity support for APS' $250 million commercial paper program, as well as an additional $75 million for other liquidity needs and miscellaneous letters of credit.

On June 29, 2004, APS issued $300 million of 5.80% senior unsecured notes due June 30, 2014. The proceeds from the sale of the notes were used to redeem $100 million in aggregate principal amount of APS' 6.25% Notes due January 15, 2005 and a portion of $300 million in aggregate principal amount of APS' 7.625% Notes due August 1, 2005.

On March 1, 2005, Maricopa County, Arizona Pollution Control Corporation issued $164 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2029. The bonds were issued to refinance $164 million of outstanding pollution control bonds. The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Maricopa County, Arizona Pollution Control Corporation. These bonds are classified as long-term debt on our Consolidated Balance Sheets.

APS has retired all first mortgage bonds issued by APS under its 1946 mortgage and deed of trust, including the first mortgage bonds securing APS senior notes. On April 30, 2004, APS terminated its mortgage and deed of trust and, as a result, is not able to issue any additional first mortgage bonds under that mortgage.

APS' outstanding debt was approximately $2.7 billion at December 31, 2004. APS had committed lines of credit with various banks of $325 million at December 31, 2004 which were available either to support the issuance of commercial paper or to be used for bank borrowings, including issuances of letters of credit. At December 31, 2004, APS had no outstanding commercial paper or bank borrowings. APS ended 2004 in an invested position.

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

Pinnacle West Energy

Pinnacle West Energy's capital requirements consist primarily of capital expenditures. In May 2004, SNWA paid Pinnacle West Energy approximately $91 million for a 25% interest in the 570 MW Silverhawk combined cycle plant. See the capital expenditures table above for actual capital expenditures for 2004 and projected capital expenditures for the next three years. Pinnacle West Energy's sources of cash will be cash infusions from the parent and cash from operations.

See "ACC Financing Order" in Note 3 for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in 2004 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

In 2004, SunCor did not issue any long-term debt; and it redeemed, refinanced or repaid $2 million in long-term debt (see Note 6).

SunCor's total outstanding debt was approximately $87 million as of December 31, 2004. SunCor's total short-term debt was $71 million at December 31, 2004, including $35 million of short-term borrowings outstanding under a $90 million line of credit. SunCor's long-term debt, including current maturities, totaled $16 million at December 31, 2004.

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

El Dorado funded its cash requirements during the past three years, primarily for NAC in 2002, with cash infused by the parent company and with cash from operations. As described above, during 2004, El Dorado sold its limited partnership interest in the Phoenix Suns and its ownership interest in NAC. El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments.

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company and with cash from operations.

CRITICAL ACCOUNTING POLICIES

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

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $135 million of regulatory assets on the Consolidated Balance Sheets at December 31, 2004. A component of the 2004 Settlement Agreement, which is subject to ACC approval, would allow APS to acquire the PWEC Dedicated Assets from Pinnacle West Energy, with a net carrying value of approximately $850 million, and rate base the PWEC Dedicated Assets at a rate base value of $700 million. This would result in a mandatory rate base disallowance of approximately $150 million. As a result, for financial reporting purposes, APS would recognize a one-time, after-tax net plant write-off of approximately $90 million in the period when the plant transfer to APS is completed and would reduce annual depreciation expense by approximately $5 million. See Notes 1 and 3 for more information about regulatory assets, APS' general rate case and the 2004 Settlement Agreement.

Pensions and Other Postretirement Benefit Accounting

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

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2004 projected benefit obligation, our 2004 reported pension liability on the Consolidated Balance Sheets and our 2004 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)		
	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Expense
Actuarial Assumption (a)			
Discount rate:			
Increase 1%	$ (192)	$ (159)	$ (8)
Decrease 1%	220	184	8
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(4)
Decrease 1%	–	–	4

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2004 accumulated other postretirement benefit obligation and our 2004 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on Pinnacle West's Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)	
	Impact on Accumulated Other Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Actuarial Assumption (a)		
Discount rate:		
Increase 1%	$ (80)	$ (4)
Decrease 1%	94	4
Health care cost trend rate (b):		
Increase 1%	96	6
Decrease 1%	(76)	(5)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	–	(1)
Decrease 1%	–	1

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.
(b) This assumes a 1% change in the initial and ultimate health care cost trend rate.

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

Derivative Accounting

Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting (for contracts designated as normal) or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in the fair value are recognized periodically

in income unless certain hedge criteria are met. For fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item associated with the hedged risk are recognized in earnings. For cash flow hedges, changes in the fair value of the derivative are recognized in common stock equity (as a component of other comprehensive income (loss)).

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

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

We adopted EITF 02-3 in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

See Notes 1 and 18 for further information on accounting for derivatives.

Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 20 for discussion of VIEs.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

APS General Rate Case

We believe APS' general rate case, including the proposed settlement pending before the ACC is the key issue affecting our outlook. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3 for a detailed discussion of this rate case and proposed settlement.

Factors Affecting Operating Revenues, Purchased Power and Fuel Costs

General Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale power markets in the western United States. These revenues are affected by electricity sales volumes related to customer mix, customer growth and average usage per customer as well as electricity prices and variations in weather from period to period. Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competition.

Customer and Sales Growth The customer and sales growth referred to in this paragraph applies to Native Load customers and sales to them. Customer growth in APS' service territory averaged about 3.4% a year for the three years 2002 through 2004; we currently expect customer growth to average about 3.8% per year from 2005 to 2007. We currently estimate that total retail electricity sales in kilowatt-hours will grow 5.0% on average, from 2005 through 2007, before the effects of weather variations. Customer growth for the year ended December 31, 2004 compared with the prior year was 3.7%.

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

Retail Rate Changes APS has a rate settlement agreement pending before the ACC that includes, among other things, a proposed general rate increase of 4.21% and a power supply adjuster that would provide timely recovery of variations in purchased power and fuel prices. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3. APS expects to file another general rate case in late 2005.

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

Trading In accordance with GAAP, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," in the fourth quarter of 2002. As a consequence, we are recording structured trading transactions completed prior to implementation of EITF 02-3 that do not qualify as derivatives for financial accounting purposes on the accrual method, recognizing the revenues and associated purchased power and fuel costs as the respective commodities are delivered. We expect the deliveries under these historical contracts to contribute the following amounts to net income: approximately $12 million each year in 2005 through 2007 and approximately $7 million in 2008.

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, transmission availability or constraints, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs. See "Natural Gas Supply" in Note 11 for more information on fuel costs. See "APS General Rate Case; 2004 Settlement Agreement" in Note 3 for information regarding a power supply adjuster.

Wholesale Power Market Conditions The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with its costs of serving retail customer demand. We moved this division to APS in early 2003 for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting APS' transfer of generating assets to Pinnacle West Energy. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Our future earnings will be affected by the strength or weakness of the wholesale power market. The market has suffered a substantial reduction in overall liquidity because there are fewer creditworthy counterparties and because several key participants have exited the market or scaled back their activities.

Other Factors Affecting Financial Results

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

Depreciation and Amortization Expenses Depreciation and amortization expenses are impacted by net additions to utility plant and other property, which includes generation construction or acquisition, and changes in regulatory asset amortization. Silverhawk was placed in service in May 2004. APS plans to acquire the Sundance Plant in 2005 and, in accordance with the proposed rate settlement, to issue requests for proposals to acquire additional long-term resources in 2006 and 2007. As part of the 1999 Settlement Agreement, APS amortized certain regulatory assets over a period that ended June 30, 2004. Amortization in the last three years is as follows (dollars in millions):

2002	2003	2004
$115	$86	$18

Property Taxes Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate for APS, which currently owns the majority of our property, was 9.2% of assessed value for 2004 and 9.3% for 2003. We expect property taxes to increase primarily due to our generation construction program, as the plants phase-in to the property tax base, the planned acquisition of the Sundance Plant and our additions to existing facilities.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop accruing

capitalized interest on a project when it is placed in commercial operation. As noted above, we placed new power plants in commercial operation in 2001, 2002, 2003 and 2004. Interest expense is also affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs. In addition, see Note 1 for a discussion of AFUDC.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

Subsidiaries In the case of SunCor, efforts to accelerate asset sales activities in 2004 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Consolidated Statements of Income. SunCor's net income was $45 million in 2004. See Note 22 for further discussion. We anticipate SunCor's earnings contributions in 2005 to be approximately $50 million after income taxes.

El Dorado's historical results are not indicative of future performance. El Dorado's income before taxes in 2004 was $40 million. Income taxes were recorded at the parent company. The year ended 2004 includes a $35 million gain ($21 million after tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns. El Dorado sold its investment in NAC on November 18, 2004, which resulted in a pretax gain of $4 million and is classified as discontinued operations in 2004 and prior years. See Note 22 for information regarding the sale of NAC.

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

Market Risks

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

Interest Rate and Equity Risk

Our major financial market risk exposure is to changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 12). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% senior note. These transactions qualify as fair value hedges under SFAS No 133. See Note 6.

The tables below present contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2004 and 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004					
	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2005	4.21%	$ 71,030	1.81%	$ 214,967	7.27%	$ 402,198
2006	–	–	6.55%	2,918	6.45%	395,314
2007	–	–	4.81%	302	5.99%	1,154
2008	–	–	5.22%	5,294	5.51%	1,055
2009	–	–	–	–	5.51%	818
Years thereafter	–	–	1.31%	516,340	4.79%	1,669,901
Total		$ 71,030		$ 739,821		$ 2,470,440
Fair value		$ 71,030		$ 740,271		$ 2,574,608

	2003					
	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2004	4.26%	$ 86,081	1.57%	$ 280,749	5.33%	$ 424,165
2005	–	–	1.99%	165,469	7.27%	403,204
2006	–	–	6.55%	2,937	6.49%	391,585
2007	–	–	4.99%	373	5.54%	1,256
2008	–	–	5.19%	5,269	5.55%	1,098
Years thereafter	–	–	1.84%	106,520	5.83%	1,547,775
Total		$ 86,081		$ 561,317		$ 2,769,083
Fair value		$ 86,081		$ 561,447		$ 2,913,085

The tables below present contractual balances of APS' long-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2004 and 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004			
	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount
2005	1.22%	$ 49,520	7.27%	$ 401,727
2006	–	–	6.72%	86,082
2007	–	–	5.51%	867
2008	–	–	5.51%	1,054
2009	–	–	5.51%	818
Years thereafter	1.31%	516,340	4.79%	1,669,901
Total		$ 565,860		$ 2,160,449
Fair value		$ 565,799		$ 2,254,061

	2003			
	Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
	Interest Rates	Amount	Interest Rates	Amount
2004	1.57%	$ 280,340	6.16%	$ 206,727
2005	–	–	7.27%	402,259
2006	–	–	6.73%	85,451
2007	–	–	5.55%	1,134
2008	–	–	5.55%	1,098
Years thereafter	1.84%	106,520	5.83%	1,547,775
Total		$ 386,860		$ 2,244,444
Fair value		$ 386,906		$ 2,365,821

Commodity Price Risk

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

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

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

The following tables show the pretax changes in mark-to-market of our non-trading and trading derivative positions in 2004 and 2003 (dollars in millions):

	2004		2003	
	Regulated Electricity	Marketing and Trading	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at beginning of year	$ –	$ 69	$ (49)	$ 57
Change in mark-to-market gains/(losses) for future period deliveries	11	21	(5)	(7)
Changes in cash flow hedges recorded in OCI	43	37	41	44
Ineffective portion of changes in fair value recorded in earnings	(2)	1	8	–
Mark-to-market losses/(gains) realized during the year	(18)	(21)	5	(25)
Mark-to-market of net positions at end of year	$ 34	$ 107	$ –	$ 69

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

Regulated Electricity

Source of Fair Value	2005	2006	2007	Total Fair Value
Prices actively quoted	$ 27	$ 10	$ (2)	$ 35
Prices provided by other external sources	–	–	–	–
Prices based on models and other valuation methods	(1)	–	–	(1)
Total by maturity	$ 26	$ 10	$ (2)	$ 34

Marketing and Trading

Source of Fair Value	2005	2006	2007	2008	2009	Years Thereafter	Total Fair Value
Prices actively quoted	$ 44	$ –	$ –	$ –	$ –	$ –	$ 44
Prices provided by other external sources	1	32	42	24	(1)	(2)	96
Prices based on models and other valuation methods	(9)	(6)	(13)	(6)	–	1	(33)
Total by maturity	$ 36	$ 26	$ 29	$ 18	$ (1)	$ (1)	$ 107

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on Pinnacle West's Consolidated Balance Sheets at December 31, 2004 and 2003 (dollars in millions).

	December 31, 2004 Gain (Loss)		December 31, 2003 Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):				
Electricity	$ (4)	$ 4	$ (2)	$ 2
Natural gas	2	(2)	(1)	1
Other	1	(1)	1	–
Mark-to-market changes reported in OCI (b):				
Electricity	35	(35)	36	(36)
Natural gas	43	(43)	30	(30)
Total	$ 77	$ (77)	$ 64	$ (63)

(a) These contracts are primarily structured sales activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.

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

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 35% of Pinnacle West's $391 million of risk management and trading assets as of December 31, 2004. See Note 1, "Derivative Accounting" for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements based on current expectations, and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. These forward-looking statements are often identified by words such as "estimate," "predict," "hope," "may," "believe," "anticipate," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include, but are not limited to:

- state and federal regulatory and legislative decisions and actions, including the outcome of the rate case APS filed with the ACC on June 27, 2003 and the wholesale electric price mitigation plan adopted by the FERC;
- the outcome of regulatory, legislative and judicial proceedings relating to the restructuring;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- market prices for electricity and natural gas;
- power plant performance and outages, including transmission outages and constraints;
- weather variations affecting local and regional customer energy usage;
- customer growth and energy usage;
- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile purchased power and fuel costs and the completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies;
- the cost of debt and equity capital and access to capital markets;

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13(a) - 15(f). Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein and relates also to the Company's consolidated financial statements.

March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2004. We also have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management's assessment, and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM *(continued)*

accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Note 18 to the consolidated financial statements, in 2002 the Company changed its method for accounting for trading activities in order to comply with the provisions of Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 15, 2005

CONSOLIDATED STATEMENTS OF INCOME *(dollars and shares in thousands, except per share amounts)*

	Year Ended December 31,		
	2004	2003	2002
OPERATING REVENUES			
Regulated electricity segment	$ 2,035,247	$ 1,978,075	$ 1,890,391
Marketing and trading segment	461,870	391,886	286,879
Real estate segment	359,792	361,604	201,081
Other revenues	42,816	27,929	26,899
Total	2,899,725	2,759,494	2,405,250
OPERATING EXPENSES			
Regulated electricity segment purchased power and fuel	567,433	517,320	376,911
Marketing and trading segment purchased power and fuel	382,147	344,862	154,987
Operations and maintenance	596,557	548,732	584,538
Real estate operations segment	289,900	305,974	185,925
Depreciation and amortization	401,105	435,140	422,299
Taxes other than income taxes	122,216	110,270	107,952
Other expenses	34,108	23,254	21,895
Total	2,393,466	2,285,552	1,854,507
OPERATING INCOME	506,259	473,942	550,743
OTHER			
Allowance for equity funds used during construction	4,885	14,240	–
Other income (Note 19)	53,989	35,563	14,910
Other expenses (Note 19)	(21,510)	(20,574)	(33,655)
Total	37,364	29,229	(18,745)
INTEREST EXPENSE			
Interest charges	195,859	204,339	187,039
Capitalized interest	(16,311)	(29,444)	(43,749)
Total	179,548	174,895	143,290
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	364,075	328,276	388,708
INCOME TAXES	128,857	102,473	152,145
INCOME FROM CONTINUING OPERATIONS	235,218	225,803	236,563
Income (loss) from discontinued operations – net of income tax expense (benefit) of $5,480, $9,616 and ($14,045)	7,977	14,776	(21,410)
Cumulative effect of a change in accounting for trading activities – net of income tax benefit of ($43,123)	–	–	(65,745)
NET INCOME	$ 243,195	$ 240,579	$ 149,408
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	91,397	91,265	84,903
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	91,532	91,405	84,964
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations – basic	$ 2.57	$ 2.47	$ 2.79
Net income – basic	2.66	2.64	1.76
Income from continuing operations – diluted	2.57	2.47	2.78
Net income – diluted	2.66	2.63	1.76
DIVIDENDS DECLARED PER SHARE	$ 1.825	$ 1.725	$ 1.625

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS *(dollars in thousands)*

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 163,366	$ 131,062
Investment in debt securities	181,175	91,850
Customer and other receivables	367,863	354,666
Allowance for doubtful accounts	(4,896)	(9,223)
Accrued utility revenues	93,227	88,629
Materials and supplies (at average cost)	101,333	96,099
Fossil fuel (at average cost)	20,512	28,367
Assets from risk management and trading activities (Note 18)	166,896	97,630
Assets related to discontinued operations (Note 22)	–	23,065
Other current assets	47,654	72,649
Total current assets	1,137,130	974,794
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	382,398	358,441
Assets from risk management and trading activities – long-term (Note 18)	224,341	138,946
Decommissioning trust accounts (Note 12)	267,700	240,645
Other assets	107,212	88,473
Total investments and other assets	981,651	826,505
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 9 AND 10)		
Plant in service and held for future use	10,486,648	9,904,874
Less accumulated depreciation and amortization	3,365,954	3,145,609
Total	7,120,694	6,759,265
Construction work in progress	258,119	554,876
Intangible assets, net of accumulated amortization of $158,584 and $128,126	105,486	108,534
Nuclear fuel, net of accumulated amortization of $59,020 and $58,053	51,188	52,011
Net property, plant and equipment	7,535,487	7,474,686
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	135,051	132,349
Other deferred debits	107,428	110,708
Total deferred debits	242,479	243,057
TOTAL ASSETS	$ 9,896,747	$ 9,519,042

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS *(dollars in thousands)*

	December 31, 2004	December 31, 2003
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 373,526	$ 283,021
Accrued taxes	245,611	69,769
Accrued interest	38,795	51,825
Short-term borrowings (Note 5)	71,030	86,081
Current maturities of long-term debt (Note 6)	617,165	704,914
Customer deposits	55,558	49,783
Deferred income taxes (Note 4)	9,057	631
Liabilities from risk management and trading activities (Note 18)	113,406	92,755
Liabilities related to discontinued operations (Note 22)	–	16,427
Other current liabilities	101,748	77,362
Total current liabilities	1,625,896	1,432,568
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,584,985	2,616,585
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,227,553	1,338,527
Regulatory liabilities (Notes 1, 3 and 4)	506,646	468,694
Liability for asset retirements (Note 12)	251,612	234,440
Pension liability (Note 8)	234,445	188,041
Liabilities from risk management and trading activities – long-term (Note 18)	156,262	82,730
Unamortized gain – sale of utility plant (Note 9)	50,333	54,909
Other	308,819	272,769
Total deferred credits and other	2,735,670	2,640,110
COMMITMENTS AND CONTINGENCIES (NOTES 3, 11 AND 12)		
COMMON STOCK EQUITY (NOTE 7)		
Common stock, no par value; authorized 150,000,000 shares; issued 91,802,861 at end of 2004 and 91,379,947 at end of 2003	1,769,047	1,744,354
Treasury stock at cost; 9,522 shares at end of 2004 and 92,015 shares at end of 2003	(428)	(3,273)
Total common stock	1,768,619	1,741,081
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(81,788)	(66,564)
Derivative instruments	59,243	27,563
Total accumulated other comprehensive loss	(22,545)	(39,001)
Retained earnings	1,204,122	1,127,699
Total common stock equity	2,950,196	2,829,779
TOTAL LIABILITIES AND EQUITY	$ 9,896,747	$ 9,519,042

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS *(dollars in thousands)*

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 243,195	$ 240,579	$ 149,408
Adjustment to reconcile net income to net cash provided by operating activities:			
Loss (income) from discontinued operations, net of tax	(7,977)	(14,776)	21,410
Cumulative effect of accounting change, net of tax	–	–	65,745
Equity earnings in Phoenix Suns partnership	(34,594)	–	–
Depreciation and amortization	401,105	435,140	422,299
Nuclear fuel amortization	30,446	28,757	31,185
Allowance for equity funds used during construction	(4,885)	(14,240)	–
Deferred income taxes	(113,850)	81,756	191,135
Change in mark-to-market valuations	(18,915)	17,410	(18,146)
Redhawk Units 3 and 4 cancellation charge	–	–	49,192
Changes in current assets and liabilities:			
Customer and other receivables	(17,524)	(12,456)	60,336
Accrued utility revenues	(4,598)	5,875	(18,373)
Materials, supplies and fossil fuel	2,621	(4,629)	(11,599)
Other current assets	24,995	(6,865)	(6,643)
Accounts payable	98,001	(7,125)	17,008
Accrued taxes	175,842	(1,338)	(36,041)
Accrued interest	(13,030)	(1,193)	4,212
Other current liabilities	33,669	8,668	24,755
Proceeds from the sale of real estate assets	80,035	130,597	47,906
Real estate investments	(62,812)	(51,837)	(56,355)
Increase in regulatory assets	(2,702)	(20,971)	(11,029)
Change in risk management and trading – assets	(2,549)	46,911	(11,700)
Change in risk management and trading – liabilities	13,018	(11,613)	(22,783)
Change in customer advances	6,402	7,270	(23,780)
Change in pension liability	23,822	19,074	(3,009)
Change in other long-term assets	(39,710)	13,124	(13,593)
Change in other long-term liabilities	32,075	12,635	9,785
Net cash flow provided by operating activities	842,080	900,753	861,325
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(538,232)	(713,256)	(909,259)
Proceeds from sale of Silverhawk	90,967	–	–
Capitalized interest	(16,311)	(29,444)	(43,749)
Discontinued operations – Real Estate	8,927	27,193	28,917
Discontinued operations – NAC	8,499	(19,971)	(12,259)
Proceeds from the sale of the Phoenix Suns partnership	23,101	–	–
Purchases of investment securities	(1,040,955)	(877,660)	–
Proceeds from sale of investment securities	951,630	785,810	–
Proceeds from commercial real estate properties	–	33,297	9,272
Other	(19,579)	(21,040)	36,635
Net cash flow used for investing activities	(531,953)	(815,071)	(890,443)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	478,328	656,850	674,919
Short-term borrowings and payments – net	(15,051)	(173,303)	(306,079)
Dividends paid on common stock	(166,772)	(157,417)	(137,721)
Repayment of long-term debt	(604,015)	(366,497)	(354,916)
Common stock equity issuance	18,291	–	199,238
Other	11,396	8,181	2,624
Net cash flow (used for) provided by financing activities	(277,823)	(32,186)	78,065
NET INCREASE IN CASH AND CASH EQUIVALENTS	32,304	53,496	48,947
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	131,062	77,566	28,619
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 163,366	$ 131,062	$ 77,566
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Income taxes paid/(refunded)	$ 66,447	$ 32,816	$ (17,918)
Interest paid, net of amounts capitalized	$ 191,865	$ 161,581	$ 126,322

See Notes to Pinnacle West's Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY *(dollars in thousands)*

	Year Ended December 31,		
	2004	2003	2002
COMMON STOCK (NOTE 7)			
Balance at beginning of year	$ 1,744,354	$ 1,737,258	$ 1,536,924
Issuance of common stock	18,291	–	199,238
Other	6,402	7,096	1,096
Balance at end of year	1,769,047	1,744,354	1,737,258
TREASURY STOCK (NOTE 7)			
Balance at beginning of year	(3,273)	(4,358)	(5,886)
Purchase of treasury stock	(2,986)	–	(5,971)
Reissuance of treasury stock used for stock compensation, net	5,831	1,085	7,499
Balance at end of year	(428)	(3,273)	(4,358)
RETAINED EARNINGS			
Balance at beginning of year	1,127,699	1,044,537	1,032,850
Net income	243,195	240,579	149,408
Common stock dividends	(166,772)	(157,417)	(137,721)
Balance at end of year	1,204,122	1,127,699	1,044,537
ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)			
Balance at beginning of year	(39,001)	(91,284)	(64,565)
Minimum pension liability adjustment, net of tax expense (benefit) of ($9,756), $3,700 and ($46,109)	(15,224)	4,700	(70,298)
Unrealized gain on derivative instruments, net of tax expense of $31,117, $33,298 and $28,820	48,226	51,089	43,939
Reclassification of realized gain to income, net of tax benefit of ($10,695), ($2,343) and ($237)	(16,546)	(3,506)	(360)
Balance at end of year	(22,545)	(39,001)	(91,284)
TOTAL COMMON STOCK EQUITY	$ 2,950,196	$ 2,829,779	$ 2,686,153
COMPREHENSIVE INCOME (LOSS)			
Net income	$ 243,195	$ 240,579	$ 149,408
Other comprehensive income (loss)	16,456	52,283	(26,719)
Comprehensive income	$ 259,651	$ 292,862	$ 122,689

See Notes to Pinnacle West's Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

Pinnacle West's Consolidated Financial Statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado (principally NAC). See Note 22 for a discussion of the sale of NAC in November 2004. Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated generation operations. APS Energy Services was formed in 1998 and provides competitive commodity energy and energy-related products to key customers in competitive markets in the western United States. SunCor is a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico, Idaho and Utah. El Dorado is an investment firm.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We account for our derivative contracts in accordance with SFAS No. 133, as amended by SFAS No. 149, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if certain hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 2002, we adopted EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133, as amended. Energy trading contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

Under fair value (mark-to-market) accounting, derivative contracts for the purchase or sale of energy commodities are reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as current or long-term assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers, which we convert into monthly prices using historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

The credit valuation adjustment represents estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities, and local distribution companies and financial institutions. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by the ERMC.

See Note 18 for additional information about our derivative and energy trading accounting policies.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

As part of the 1999 Settlement Agreement APS amortized certain regulatory assets over a period that ended June 30, 2004. Amortization in the last three years is as follows (dollars in millions):

2002	2003	2004
$115	$86	$18

The detail of regulatory assets is as follows (dollars in millions):

	December 31,	
	2004	2003
Electric industry restructuring transition costs (Note 3)	$ 50	$ 46
Deferred compensation	24	24
Loss on reacquired debt (a)	17	12
Capital contributions on the Mead-Phoenix transmission line	13	11
Regulatory asset for deferred income taxes	12	9
Spent nuclear fuel storage (Note 11)	11	7
Balance recoverable under the 1999 Settlement Agreement	–	18
Other	8	5
Total regulatory assets	$ 135	$ 132

(a) See "Reacquired Debt Costs" below.

The detail of regulatory liabilities is as follows (dollars in millions):

	December 31,	
	2004	2003
Removal costs (a)	$ 462	$ 439
Deferred gains on utility property	20	20
Deferred interest income (b)	22	8
Other	3	2
Total regulatory liabilities	$ 507	$ 469

(a) See Note 12 for information on Asset Retirement Obligations.
(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS No. 143. The standard requires that liabilities associated with the retirement of tangible long-lived assets be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. See Note 12.

APS records a regulatory liability for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount that has been recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition and ongoing current period costs calculated in accordance with SFAS No. 143.

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2004 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 18 years;
- Other generation – 26 years;
- Transmission – 36 years;
- Distribution – 23 years; and
- Other – 8 years.

For the years 2002 through 2004, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.36% for 2004, 3.35% for 2003 and 3.35% for 2002. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 55 years.

Investments

El Dorado accounts for its investments using the equity (if significant influence) and cost (less than 20% ownership) methods. See Note 22 for a discussion of the sale of NAC.

The Company's investments have been reviewed in accordance with EITF 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," and no other-than-temporary impairments were identified.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance non-regulated construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.44% for 2004, 4.55% for 2003 and 4.80% for 2002. Capitalized interest ceases to accrue when construction is complete.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction of regulated utility plant. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.42% for 2004 and 8.55% for 2003. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

In 2003, APS returned to the AFUDC method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This is consistent with APS returning to a vertically-integrated utility, as evidenced by APS' 2003 general rate case filing, which includes the request for rate recognition of generation assets. Prior to 2003, APS capitalized interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Although AFUDC both increases the plant balance and results in higher current earnings during the construction period, AFUDC is realized in future revenues through depreciation provisions included in rates. This change increased earnings by $11 million in 2003 as compared to what it would have been under SFAS No. 34.

Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. However, the determination and billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers since the date of the last meter reading and billing and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes.

Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis on Pinnacle West's Consolidated Statements of Income. In the electricity business, some contracts to purchase energy are netted against other contracts

to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and purchased power and fuel costs.

All gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis.

Real Estate Revenues

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless both conditions exist, recognition of all or part of the income is postponed under the percentage of completion method per SFAS No. 66 "Accounting for Sales of Real Estate." SunCor recognizes income only after the assets' title has passed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided. In addition, see Note 22 – Discontinued Operations.

Real Estate Investments

Real estate investments primarily include SunCor's land, home inventory and investments in joint ventures. Land includes acquisition costs, infrastructure costs, property taxes and capitalized interest directly associated with the acquisition and development of each project. Land under development and land held for future development are stated at accumulated cost, except that, to the extent that such land is believed to be impaired, it is written down to fair value. Land held for sale is stated at the lower of accumulated cost or estimated fair value less costs to sell. Home inventory consists of construction costs, improved lot costs, capitalized interest and property taxes on homes under construction. Home inventory is stated at the lower of accumulated cost or estimated fair value less costs to sell. Investments in joint ventures for which SunCor does not have a controlling financial interest are not consolidated but are accounted for using the equity method of accounting. In 2003, SunCor acquired two joint ventures for $10 million and consolidated $53 million of assets and $43 million of liabilities, which are included on the Consolidated Balance Sheets at December 31, 2003. The $10 million cash investment is included on the other investing line of the Consolidated Statements of Cash Flow at December 31, 2003. In addition, see Note 22 – Discontinued Operations.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an initial maturity of three months or less to be cash equivalents.

We have investments in auction rate securities in which interest rates are reset on a short-term basis; however, the underlying contract maturity dates extend beyond three months. We classify the investments in auction rate securities as investments in debt securities on our Consolidated Balance Sheets. We have reclassified cash at December 31, 2003 of $92 million to investment in debt securities. Included in that reclassification is $70 million related to APS. The purchase and sale activities related to these investments have also been reclassified on the Consolidated Statement of Cash Flows.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 11 for information about spent nuclear fuel disposal and Note 12 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

Reacquired Debt Costs

For reacquired debt costs related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery of the net amount of losses in the APS general rate case (see Note 3).

Stock-Based Compensation

In 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees."

The following chart compares our net income, stock compensation expense and earnings per share to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2004 (dollars in thousands, except per share amounts):

	Year Ended December 31,		
	2004	2003	2002
Net income as reported:	$ 243,195	$ 240,579	$ 149,408
Add: Stock compensation expense included in reported net income (net of tax)	4,690	3,514	2,347
Deduct: Total stock compensation expense determined under fair value method (net of tax)	(5,311)	(5,220)	(3,742)
Pro forma net income	$ 242,574	$ 238,873	$ 148,013
Earnings per share – basic:			
As reported	$ 2.66	$ 2.64	$ 1.76
Pro forma (fair value method)	$ 2.65	$ 2.62	$ 1.74
Earnings per share – diluted:			
As reported	$ 2.66	$ 2.63	$ 1.76
Pro forma (fair value method)	$ 2.65	$ 2.61	$ 1.74

In order to calculate the fair value of the 2004, 2003 and 2002 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

	2004	2003	2002
Risk-free interest rate	3.15%	3.35%	4.17%
Dividend yield	4.76%	5.26%	4.17%
Volatility	17.04%	38.03%	22.59%
Expected life (months)	60	60	60

See Note 16 for further discussion about our stock compensation plans.

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets on Pinnacle West's Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. Amortization expense was $34 million in 2004, $25 million in 2003, and $21 million in 2002. Estimated amortization expense on existing intangible assets over the next five years is $33 million in 2005, $31 million in 2006, $25 million in 2007, $16 million in 2008, and $1 million in 2009. At December 31, 2004, the weighted average amortization period for intangible assets is 7 years.

2. NEW ACCOUNTING STANDARDS

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." The standard establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS No. 123R is effective as of the beginning of the first interim or annual period that begins after June 15, 2005. We are currently accounting for stock-based compensation using the fair value method and are evaluating the impacts of this new guidance, but we do not believe it will have a material impact on our financial statements.

See the following Notes for information about new accounting standards and other accounting matters:

- Note 8 for FSP 106-2 regarding the Medicare Prescription Drug, Improvement and Modernization Act related to retirement plans and other benefits;
- Note 18 for EITF 02-3 and DIG Issue No. C15 related to accounting for derivatives and energy contracts; and
- Note 20 for FIN No. 46R related to variable interest entities.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

APS GENERAL RATE CASE; 2004 SETTLEMENT AGREEMENT On June 27, 2003, APS filed a general rate case with the ACC and requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, intended to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

The general rate case also addresses the implementation of rate adjustment mechanisms that were the subject of ACC hearings in April 2003. The rate adjustment mechanisms, which were authorized as a result of the 1999 Settlement Agreement, would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the Rules.

On August 18, 2004, a substantial majority of the parties to the rate case, including APS, the ACC staff, the Arizona Residential Utility Consumer Office, other customer groups, and merchant power plant intervenors entered into an agreement that proposes terms under which the rate case would be settled (the "2004 Settlement Agreement").

Key financial components of the 2004 Settlement Agreement, which is subject to ACC approval are as follows:

- APS would receive an annual retail rate increase of approximately $75.5 million, or 4.21%. The increase would consist of an increase in base rates of approximately 3.77% and an increase of approximately 0.44% for recovery over five years of the past costs of compliance with the ACC's retail electric competition rules.
- APS would acquire the PWEC Dedicated Assets from Pinnacle West Energy, with a net carrying value of approximately $850 million, and rate base the PWEC Dedicated Assets at a rate base value of $700 million, which would result in a mandatory rate base disallowance of $150 million. As a result, for financial reporting purposes, APS would recognize a one-time, after-tax net plant write-off of approximately $90 million in the period when the plant transfer to APS is completed and would reduce annual depreciation expense by approximately $5 million.

- To bridge the time between the effective date of the rate increase and the actual date the PWEC Dedicated Assets transfer, APS and Pinnacle West Energy would enter into a cost-based purchase power agreement (the "Bridge PPA"), which would be based on the value of the PWEC Dedicated Assets described in the previous bullet point. The Bridge PPA would remain in effect until the FERC approves the transfer of the PWEC Dedicated Assets to APS and the transfer is completed.
  - If the FERC were to issue an order denying APS' request to acquire the PWEC Dedicated Assets, the Bridge PPA would become a 30-year purchased power agreement, with prices reflecting cost-of-service as if APS had acquired and rate-based the PWEC Dedicated Assets at the value described above.
  - If the FERC were to issue an order (a) approving APS' request to transfer the PWEC Dedicated Assets at a value materially less than $700 million, (b) approving the transfer of fewer than all of the PWEC Dedicated Assets or (c) that was materially inconsistent with the 2004 Settlement Agreement, APS would file an appropriate application with the ACC so that rates could be adjusted. In these circumstances, the Bridge PPA would continue at least until the conclusion of the subsequent proceeding to consider any appropriate adjustment to APS' rates.
- A PSA would provide for the recovery of variations in fuel and purchased power costs, subject to specified parameters and procedures.
- APS would not restore and recover in rates the $234 million write-off recorded in 1999 as a result of the 1999 Settlement Agreement. As a result, annual amortization expense for financial reporting purposes would be approximately $16 million less than if the $234 million write-off had been restored and amortized over a 15-year period as originally requested.
- APS would adopt longer service lives than originally requested for certain depreciable assets, which would have the effect of reducing annual depreciation expense for financial reporting purposes by approximately $26 million.

On February 28, 2005, the administrative law judge in the general rate case issued a recommended order. The recommended order proposes ACC approval of the 2004 Settlement Agreement with two changes related to the PSA. First, the amount of gas costs that APS could recover under the annual PSA would be limited to $500 million per year. Second, although the 2004 Settlement Agreement provides that the PSA would remain in effect for a minimum five-year period, under the recommended order the ACC would be able to eliminate the PSA at any time, if appropriate, if APS files a rate case before the expiration of the five-year period or APS does not comply with the terms of the PSA. If APS exceeds the gas costs that could be recoverable under the PSA or if the ACC eliminates the PSA, APS would retain the right to file a rate case to reset its base rates.

On March 14, 2005, the parties to the 2004 Settlement Agreement jointly filed suggested changes to the recommended order addressing, among other things, the recommended order's proposed treatment of the PSA. The ACC has scheduled open meetings on March 24 and March 28, 2005 to consider the recommended order and suggested changes. APS cannot predict the outcome of this matter.

ACC FINANCING ORDER On May 12, 2003, APS issued $500 million of debt pursuant to the Financing Order and made a $500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets.

The ACC granted the Financing Order subject to various conditions. One of these conditions is that APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC.

In addition, the Financing Order required the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. As part of the 2004 Settlement Agreement, this inquiry would be concluded with no further action by the ACC.

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

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access became available to all APS retail electricity customers.
- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002. However, as discussed below, in 2002 the ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affected the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the Rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other Rules were set aside for failure to submit such regulations to the Arizona Attorney General for approval as required by statute. A request for the Arizona Supreme Court to review the Court of Appeals decision was denied on January 4, 2005.

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

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

On November 15, 2002, APS filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company vs. Arizona Corporation Commission, CV 2002-0222 32. Arizona Public Service Company vs. Arizona Corporation Commission, 1CA CC 02-0002. On December 13, 2002, APS and the ACC staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. The major provisions of the principles include, among other things, the following:

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:
  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;
  - the appropriate treatment of the $234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and
  - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- As a result of the ACC's issuance of the Financing Order, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

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

Upon the ACC's issuance of a final, non-appealable order approving the 2004 Settlement Agreement, APS, Pinnacle West, and Pinnacle West Energy will dismiss the litigation described under this "Track A" heading.

TRACK B ORDER On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

- Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.
- PPL Energy Plus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.
- Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

Effective upon final ACC approval of the 2004 Settlement Agreement and the closing of the purchase of the Sundance Plant discussed below, the Track B contracts with Pinnacle West Energy and PPL Energy Plus, LLC will be cancelled.

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

On June 1, 2004, APS and PPL Sundance filed a joint application with the ACC with respect to APS' proposed acquisition of the Sundance Plant. On January 20, 2005, the ACC issued an order confirming APS' authority to "self-build or buy new generation assets for native load" and stated that APS' acquisition of the Sundance Plant would be a proper purpose under APS' existing ACC financing authorizations. APS' filings with the ACC also had requested that the ACC allow APS to defer for future recovery certain

capital and operating costs (net of fuel and purchased power savings) associated with the Sundance Plant acquisition until rate treatment for the Sundance Plant could be considered in APS' next general rate case. APS' filings estimated that the deferrals would be approximately $10 million to $15 million before income taxes on an annualized basis. The order issued by the ACC allows APS to record the deferrals for up to 36 months, subject to a number of conditions. However, if APS has a general rate case pending at the end of the 36-month period, the deferral period could extend until the rate case had been decided. The conditions imposed by the order are expected to substantially limit the amount of deferrals that APS will be able to record.

APS' acquisition of the Sundance Plant is subject to FERC approval and to customary closing conditions. The transaction is targeted to close in the spring of 2005.

APS does not expect to enter into any additional transactions as a result of the 2003 RFP.

PROVIDER OF LAST RESORT OBLIGATION Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. There can be no assurance that APS would be able to fully recover the costs of this power. The proposed settlement of APS' general rate case, discussed above, would, among other things, allow APS to recover purchased power costs.

1999 SETTLEMENT AGREEMENT The following are the major provisions of a settlement agreement entered into in 1999, as approved by the ACC:

- APS has reduced rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; approximately $28 million ($17 million after taxes), effective July 1, 2002; and approximately $29 million ($18 million after taxes), effective July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.
- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There was a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004.
- APS is being permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004, or when the rate case is decided. See "APS General Rate Case; 2004 Settlement Agreement" above.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" above), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001.

- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement stated that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also stated that APS will not be allowed to recover $183 million net present value (in 1999 dollars) ($234 million pretax) of the $533 million. The 1999 Settlement Agreement provided that APS will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31, 2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery of the $350 million due to sales volume variances. As part of its general rate case request, APS sought the recovery of amounts written off by APS as a result of the 1999 Settlement Agreement. That claim would be given up under the terms of the 2004 Settlement Agreement (see above).

- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as discussed above under "Track A Order," in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing an order preventing APS from transferring its generation assets. Under the 2004 Settlement Agreement, APS would recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See "APS General Rate Case; 2004 Settlement Agreement" above. Such full recovery of divestiture costs would be allowed under the 2004 Settlement Agreement (see above).

GENERAL The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

Federal

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC adopted a price cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

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

The FERC has been, through its Office of Marker Oversight and Investigations (OMOI), in the process of auditing a number of electric utilities regarding compliance with its regulations. Such an audit of APS and its affiliates was recently completed, and the FERC has issued an order approving the OMOI audit report and directing certain compliance actions. Arizona Public Service Company, 109 FERC 61,271 (2004).

Chief among the FERC's findings, APS must pay $4 million for its use of unauthorized point-to-point transmission service. Of the $4 million, APS must distribute: (1) $2.75 million to upgrade the West Phoenix-Lincoln Street 230kV transmission line with high capacity composite conductors; and (2) $1.25 million as a contribution to established low income energy assistance programs in Arizona. APS must not recover these monies from any existing or future wholesale or retail rate recovery mechanism, nor may it announce the low income payment as a public interest contribution. APS must also take certain corrective actions and make quarterly filings detailing its progress in implementing these actions until all are completed.

APS believes that the resolution of these matters will not have a material adverse effect on its financial position, results of operations or liquidity.

4. INCOME TAXES

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset and a regulatory liability related to income taxes on its Balance Sheets in accordance with SFAS No. 71. The regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. The regulatory liability relates to excess deferred taxes resulting primarily from the reduction in federal income tax rates as part of the Tax Reform Act of 1986. APS amortizes this amount as the differences reverse.

As a result of a change in IRS guidance, we claimed a tax deduction related to an APS tax accounting method change on the 2001 federal consolidated income tax return. The accelerated deduction resulted in a $200 million reduction in the current income tax liability and a corresponding increase in the plant-related deferred tax liability. In 2002, we received an income tax refund of approximately $115 million related to our 2001 federal consolidated income tax return. The 2001 federal consolidated income tax return is currently under examination by the IRS. As part of this ongoing examination, the IRS is reviewing this accounting method change and the resultant deduction. During 2004, the current income tax liability was increased, with a corresponding decrease to plant-related deferred tax liability, to reflect the expected outcome of this audit. We do not expect the ultimate outcome of this examination to have a material adverse impact on our financial position, results of operations or liquidity.

The income tax liability accounts reflect the tax and interest associated with the most probable resolution of all known and measurable tax exposures.

In 2004 and 2003, we resolved certain prior-year issues with the taxing authorities and recorded tax benefits associated with tax credits and other reductions to income tax expense.

The components of income tax expense are as follows (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Current:			
Federal	$ 200,133	$ 22,875	$ (43,492)
State	48,054	3,752	(14,732)
Total current	248,187	26,627	(58,224)
Deferred:			
Income from continuing operations	(113,850)	81,756	191,135
Discontinued operations	–	3,706	5,189
Cumulative effect of accounting change	–	–	(43,123)
Total deferred	(113,850)	85,462	153,201
Total income tax expense	134,337	112,089	94,977
Less: Income tax expense/(benefit) on discontinued operations	5,480	9,616	(14,045)
Less: Income tax benefit for cumulative effect of accounting change	–	–	(43,123)
Total income tax expense for income from continuing operations	$ 128,857	$ 102,473	$ 152,145

The following chart compares pretax income from continuing operations at the 35% federal income tax rate to income tax expense (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Federal income tax expense at 35% statutory rate	$ 127,426	$ 114,897	$ 136,048
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	13,705	11,522	18,114
Credits and favorable adjustments related to prior years resolved in current year	(6,138)	(17,944)	–
Medicare Subsidy Part-D (see Note 8)	(1,778)	–	–
Allowance for equity funds used during construction (see Note 1)	(1,547)	(4,984)	–
Other	(2,811)	(1,018)	(2,017)
Income tax expense	$ 128,857	$ 102,473	$ 152,145

The following table sets forth the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

	December 31,	
	2004	2003
Current liability	$ (9,057)	$ (631)
Long term liability	(1,227,553)	(1,338,527)
Accumulated deferred income taxes – net	$ (1,236,610)	$ (1,339,158)

The components of the net deferred income tax liability were as follows (dollars in thousands):

	December 31, 2004	December 31, 2003
DEFERRED TAX ASSETS		
Regulatory liabilities:		
Asset Retirement Obligation	$ 182,086	$ 169,322
Federal excess deferred income taxes	16,341	18,936
Other	8,282	8,302
Pension liability	91,973	73,844
Risk management and trading activities	91,021	59,293
Deferred gain on Palo Verde Unit 2 sale leaseback	19,816	21,656
Other	70,849	64,770
Total deferred tax assets	480,368	416,123
DEFERRED TAX LIABILITIES		
Plant-related	(1,516,174)	(1,614,887)
Risk management and trading activities	(146,037)	(84,124)
Regulatory assets	(54,767)	(56,270)
Total deferred tax liabilities	(1,716,978)	(1,755,281)
Accumulated deferred income taxes – net	$ (1,236,610)	$ (1,339,158)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of $325 million at December 31, 2004 and $250 million at December 31, 2003, which were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current line matures in May 2007. The commitment fees at December 31, 2004 and 2003 for these lines of credit were 0.15% and 0.175% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2004 and 2003. APS had approximately $4.8 million letters of credit issued under the line at December 31, 2004.

APS had no commercial paper borrowings outstanding at December 31, 2004 and 2003. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had committed lines of credit of $300 million at December 31, 2004 and $275 million at December 31, 2003, which were available either to support the issuance of up to $250 million in commercial paper or to be used for bank borrowings, including issuance of letters of credit. The current lines mature in October 2007. Pinnacle West had no outstanding borrowings at December 31, 2004 and December 31, 2003. Pinnacle West had approximately $13 million of letters of credit issued under the line at December 31, 2004 and approximately $15 million of letters of credit issued under the line at December 31, 2003. The commitment fees were 0.175% in 2004 and ranged from 0.125% to 0.175% in 2003. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2004 and 2003. All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

SunCor had revolving lines of credit totaling $90 million at December 31, 2004 and $120 million at December 31, 2003. The commitment fees were 0.125% in 2004 and 2003. SunCor had $35 million outstanding at December 31, 2004 and $50 million outstanding at December 31, 2003. The weighted-average interest rate was 4.50% at December 31, 2004 and 2003. Interest for 2004 and 2003 was based on LIBOR plus 2% or prime plus 0.5%. The balance is included in short-term debt on the Consolidated Balance Sheets. SunCor had other short-term loans in the amount of $36 million at December 31, 2004 and December 31, 2003. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2004 and 2003.

6. LONG-TERM DEBT

APS has retired all first mortgage bonds issued under its 1946 mortgage and deed of trust, including the first mortgage bonds securing APS senior notes. On April 30, 2004, APS terminated its mortgage and deed of trust and, as a result, is not able to issue any additional first mortgage bonds under that mortgage. SunCor's short and long-term debt is collateralized by interests in certain real property and Pinnacle West's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2004 and 2003 (dollars in thousands):

	Maturity Dates (a)	Interest Rates	December 31, 2004	2003
APS				
First mortgage bonds (b)	2004	6.625%	$ –	$ 80,000
First mortgage bonds (c)	2028	5.50%	–	25,000
First mortgage bonds (d)	2028	5.875%	–	154,000
Unamortized discount and premium			(7,968)	(8,631)
Pollution control bonds (e)	2024-2034	(f)	565,860	386,860
Pollution control bonds with senior notes	2029	5.05%	90,000	90,000
Unsecured notes (g)	2004	5.875%	–	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	300,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2033	5.625%	200,000	200,000
Unsecured notes	2015	4.650%	300,000	300,000
Unsecured notes (h)	2014	5.80%	300,000	–
Secured note	2014	6.00%	1,900	–
Senior notes (i)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2006-2012	(j)	9,854	11,749
Subtotal			2,718,341	2,622,673
SUNCOR				
Notes payable	2006-2008	(k)	15,467	17,125
Capitalized lease obligations	2005-2007	8.91%	507	728
Subtotal			15,974	17,853
PINNACLE WEST				
Senior notes (l)	2006	6.40%	302,589	515,000
Unamortized discount and premium			(143)	(270)
Floating rate senior notes	2005	(m)	165,000	165,000
Capitalized lease obligations	2005-2007	5.45%	389	1,243
Subtotal			467,835	680,973
Total long-term debt (n)			3,202,150	3,321,499
Less current maturities (n)			617,165	704,914
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 2,584,985	$ 2,616,585

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.
(b) On March 1, 2004, APS redeemed at maturity $80 million of its First Mortgage Bonds, 6.625% Series due 2004.
(c) On March 31, 2004, APS redeemed $25 million of its First Mortgage Bonds, 5.5% Series due 2028.
(d) On March 31, 2004, APS redeemed $154 million of its First Mortgage Bonds, 5.875% Series due 2028.
(e) On March 31, 2004, Navajo County, Arizona Pollution Control Corporation issued $166 million of variable interest rate pollution control bonds, 2004 Series A-E, due 2034. The bonds were issued to refinance $166 million of outstanding pollution control bonds. The refinanced bonds were all $25 million of the Navajo 5.50% bonds due 2028 (see (c) above) and $141 million of the Navajo 5.875% bonds due 2028 (see (d) above). The Series A-E bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Navajo County, Arizona Pollution Control Corporation. Also on March 31, 2004, Coconino County, Arizona Pollution Control Corporation issued $13 million of variable interest rate pollution control bonds, 2004 Series A, due 2034. The bonds were issued to refinance $13 million of outstanding pollution control bonds. The refinanced bonds were $13 million of the Coconino 5.875% bonds due 2028 (see (d) above). The Series A bonds are payable solely from revenues obtained from APS pursuant to a loan agreement between APS and Coconino County, Arizona Pollution Control Corporation.

(f) The weighted-average rate was 1.89% at December 31, 2004 and 1.51% at December 31, 2003. Changes in short-term interest rates would affect the costs associated with this debt.
(g) On February 15, 2004, APS redeemed at maturity $125 million of its 5.875% Notes due 2004.
(h) On June 29, 2004, APS issued $300 million of 5.80% senior unsecured notes due June 30, 2014. The proceeds from the sale of the notes were used to redeem $100 million in aggregate principal amount of APS' 6.25% Notes due January 15, 2005 and a portion of $300 million in aggregate principal amount of APS' 7.625% Notes due August 1, 2005.
(i) Through April 30, 2004, APS had outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the $90 million issue due in 2029. The senior note mortgage bonds had the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. As long as the senior note mortgage bonds secured the senior notes, the senior notes effectively ranked equally with the first mortgage bonds. On April 30, 2004, when APS repaid all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds were released from the senior note indenture, resulting in their no longer securing the senior notes and ceasing to be outstanding.
(j) The weighted average rate was 5.78% at December 31, 2004 and 5.55% at December 31, 2003. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2004 and December 31, 2003.
(k) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.50%. There are also two notes at fixed rates of 8.00% and 10.00%.
(l) On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the $300 million 6.40% senior note. The transaction qualifies as a fair value hedge under SFAS No. 133.
(m) The weighted average rate was 2.06% at December 31, 2004 and 1.98% at December 31, 2003.
(n) $281 million of pollution control bonds at December 31, 2003 have been reclassified from long-term to current maturities. The bond holders had the ability to put these bonds to APS in the short-term on the interest rate reset date. Without a demonstrated intent to finance on a long-term basis (by use of credit agreements that extend for more than one year, etc.), GAAP requires the classification of the obligations as current maturities.

Pinnacle West's and APS' debt covenants related to their respective bank financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet those and significant covenant requirements. These covenants require that the ratio of debt to total capitalization cannot exceed 65% for the Company and for APS. At December 31, 2004, the ratio was approximately 53% for Pinnacle West and 54% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2004 results, the coverages were approximately 4 times for the Company and 4 times for APS. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

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

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in our financial condition or financial prospects, except that Pinnacle West and APS do not have a material adverse change restriction for revolver borrowings equal to outstanding commercial paper amounts.

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

- $618 million in 2005;
- $398 million in 2006;
- $174 million in 2007;
- $7 million in 2008;
- $1 million in 2009; and
- $2,012 million, thereafter.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2004, 2003 and 2002 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 2001	84,824,947	$ 1,536,924	(101,307)	$ (5,886)
Common stock issuance	6,555,000	199,238	–	–
Purchase of treasury stock	–	–	(150,500)	(5,971)
Reissuance of treasury stock for stock compensation (net)	–	–	126,977	7,499
Other	–	1,096	–	–
Balance at December 31, 2002	91,379,947	1,737,258	(124,830)	(4,358)
Reissuance of treasury stock for stock compensation (net)	–	–	32,815	1,085
Other	–	7,096	–	–
Balance at December 31, 2003	91,379,947	1,744,354	(92,015)	(3,273)
Common stock issuance	422,914	18,291	–	–
Purchase of treasury stock	–	–	(80,000)	(2,986)
Reissuance of treasury stock for stock compensation (net)	–	–	162,493	5,831
Other	–	6,402	–	–
Balance at December 31, 2004	91,802,861	$ 1,769,047	(9,522)	$ (428)

8. RETIREMENT PLANS AND OTHER BENEFITS

Pinnacle West sponsors a qualified defined benefit and account balance pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance plan for all new employees in place of the defined benefit plan and, as of April 1, 2003, the plan was offered as an alternative to the defined benefit plan for all existing employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees. The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. Generally, we calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors other postretirement benefits for the employees of Pinnacle West and our subsidiaries. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

Pinnacle West uses a December 31 measurement date for its pension and other postretirement benefit plans.

On December 8, 2003, the President signed the "Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the Act). One feature of the Act is a government subsidy of prescription drug cost. The FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," to address the accounting for the effects of the Act. During the third quarter of 2004, we retroactively adopted the provisions of FSP 106-2, resulting in the remeasurement of our postretirement benefit plans' accumulated postretirement benefit obligation as of December 31, 2003. The impact of the subsidy is a decrease in the accumulated projected benefit obligation of approximately $65 million and a decrease of approximately $11 million in the net periodic postretirement benefit cost for 2004. The 2004 after-tax reduction to expense is approximately $5 million, excluding amounts capitalized as construction overhead or billed to electric plant participants.

The following table provides details of the plans' benefit costs. Also included is the portion of these costs charged to expense, including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants (dollars in thousands):

	Pension			Other Benefits		
	2004	2003	2002	2004	2003	2002
Service cost – benefits earned during the period	$ 41,207	$ 37,662	$ 30,333	$ 17,557	$ 15,858	$ 12,036
Interest cost on benefit obligation	81,873	76,951	71,242	29,488	30,163	25,235
Expected return on plan assets	(78,790)	(65,046)	(75,652)	(24,773)	(18,762)	(21,116)
Amortization of:						
Transition (asset)/obligation	(3,227)	(3,227)	(3,227)	3,005	3,005	4,001
Prior service cost/(credit)	2,401	2,401	2,912	(125)	(125)	(75)
Net actuarial loss	17,946	18,135	1,846	7,414	9,714	3,072
Net periodic benefit cost	$ 61,410	$ 66,876	$ 27,454	$ 32,566	$ 39,853	$ 23,153
Portion of cost charged to expense	$ 25,792	$ 30,094	$ 13,727	$ 13,678	$ 17,934	$ 11,577
APS share of costs charged to expense	$ 22,483	$ 25,450	$ 10,947	$ 11,923	$ 15,166	$ 9,232

The following table sets forth the plans' changes in the benefit obligations for the plan years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Benefit obligation at January 1	$ 1,307,628	$ 1,069,577	$ 540,181	$ 409,874
Service cost	41,207	37,662	17,557	15,858
Interest cost	81,873	76,951	29,488	30,163
Benefit payments	(45,195)	(43,869)	(14,332)	(15,749)
Actuarial losses/(gains)	68,731	171,420	(36,681)	106,475
Plan amendments	–	(4,113)	–	(6,440)
Benefit obligation at December 31	$ 1,454,244	$ 1,307,628	$ 536,213	$ 540,181

The following table sets forth the qualified pension plan and other benefit plan changes in the fair value of plan assets for the years 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Fair value of plan assets at January 1	$ 887,311	$ 720,807	$ 294,051	$ 223,474
Actual return on plan assets	102,829	162,571	32,433	46,071
Employer contributions	35,000	46,000	32,600	39,852
Benefit payments	(42,858)	(42,067)	(7,000)	(15,346)
Fair value of plan assets at December 31	$ 982,282	$ 887,311	$ 352,084	$ 294,051

The following table shows a reconciliation of the funded status of the plans to the amounts recognized on the Consolidated Balance Sheets as of December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Funded status at December 31	$ (471,962)	$ (420,317)	$ (184,129)	$ (246,130)
Unrecognized net transition (asset)/obligation	(3,873)	(7,099)	24,039	27,044
Unrecognized prior service cost/(credit)	14,234	16,634	(1,422)	(1,547)
Unrecognized net actuarial losses	375,980	348,982	158,271	217,611
Benefit liability recognized in the Consolidated Balance Sheets	$ (85,621)	$ (61,800)	$ (3,241)	$ (3,022)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets at December 31, 2004 and 2003 (dollars in thousands):

	Pension		Other Benefits	
	2004	2003	2004	2003
Accrued benefit cost	$ (85,621)	$ (61,800)	$ (3,241)	$ (3,022)
Additional minimum liability	(148,824)	(126,241)	–	–
Total liability	(234,445)	(188,041)	(3,241)	(3,022)
Intangible asset	14,234	16,634	–	–
Accumulated other comprehensive loss (pretax)	134,590	109,607	–	–
Net amount recognized	$ (85,621)	$ (61,800)	$ (3,241)	$ (3,022)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2004 and 2003 (dollars in thousands):

	2004	2003
Decrease/(increase) in minimum liability included in other comprehensive income – net of tax:		
Pinnacle West consolidated	$ (15,225)	$ 4,700
APS share	$ (13,930)	$ 4,329

The following table sets forth the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets for the plan years 2004 and 2003 (dollars in thousands):

	Year Ended December 31,	
	2004	2003
Projected benefit obligation	$ 1,454,244	$ 1,307,628
Accumulated benefit obligation	$ 1,216,727	$ 1,075,352
Less fair value of plan assets	982,282	887,311
Pinnacle West pension liability	$ 234,445	$ 188,041
APS share of pension liability	$ 203,668	$ 160,639

Below are the weighted-average assumptions for both the pension and other benefits used to determine each respective benefit obligation and net periodic benefit cost:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2004	2003	2004	2003
Discount rate – pension	5.84%	6.10%	6.10%	6.75%
Discount rate – other benefits	5.92%	6.10%	6.10%	6.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	N/A	N/A	9.00%	9.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	8.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care trend rate is reached	2009	2008	2008	2007

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2005, we are assuming a 9% rate of return on plan assets. As recent history has demonstrated, markets may decline and increase dramatically. However, we believe the long-term rate of return on plan assets of 9% is reasonable given our asset allocation in relation to historical and expected future performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 6	$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	$ 10	$ (8)
Effect on the accumulated other postretirement benefit obligation	$ 96	$ (76)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2004 and 2003 is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2004	2003	
ASSET CATEGORY			
Equity securities	60%	65%	60%
Fixed income	27	23	30%
Other	13	12	10%
Total	100%	100%	

The Board of Directors has established an investment policy for the pension plan assets and has delegated oversight of the plan assets to an Investment Management Committee. The investment policy sets forth the objective of providing for future pension benefits by maximizing return consistent with acceptable levels of risk. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, prohibition of investments in Pinnacle West securities, and external management of plan assets.

Pinnacle West's other postretirement benefit plans' asset allocation at December 31, 2004 and 2003, is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2004	2003	
ASSET CATEGORY			
Equity securities	71%	71%	70%
Fixed income	23	25	27%
Other	6	4	3%
Total	100%	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the postretirement benefit plans. The investment policy for other postretirement benefit plans assets is similar to that of the pension plan assets described above.

Contributions

The minimum required contribution to be made to our pension plan in 2005 is estimated to be approximately $50 million. The contribution to be made to other postretirement benefit plans in 2005 is estimated to be approximately $40 million. APS' share is approximately 92% of both plans.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter are estimated to be as follows (dollars in thousands):

	Pension	Other Benefits (a)
2005	$ 47,365	$ 15,595
2006	50,848	15,470
2007	54,381	16,947
2008	59,021	18,404
2009	64,858	20,095
Years 2010-2014	443,578	139,329

(a) The expected future other benefit payments take into account the Medicare Part D subsidy.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. In 2004, APS represented 91% of the total cost of this plan. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account. Under this plan, the Company matches a percentage of the participants' contributions in the form of Pinnacle West stock. After a five year vesting period, participants have an option to transfer the Company matching contributions out of the Pinnacle West Stock Fund to other investment funds within the plan. At December 31, 2004, approximately 22% of total plan assets were in Pinnacle West stock. Pinnacle West recorded expenses for this plan of approximately $5 million for each of the years 2004, 2003 and 2002. APS recorded expenses for this plan of approximately $5 million in 2004, $5 million in 2003 and $4 million in 2002.

9. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Rent expense is calculated on a straight-line basis. See Note 20 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale leaseback transactions.

In addition, we lease certain land, buildings, equipment, vehicles and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $69 million in 2004, $67 million in 2003 and $67 million in 2002.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2005 to 2015.

Estimated future minimum lease payments for Pinnacle West's operating leases are approximately as follows (dollars in millions):

Year	
2005	$ 73
2006	70
2007	69
2008	67
2009	65
Thereafter	368
Total future lease commitments	$ 712

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. Pinnacle West Energy shares ownership of its Silverhawk Plant. Our share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense. The following table shows APS' and Pinnacle West Energy's interests in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2004 (dollars in thousands):

	Percent Owned	Plant in Service	Accumulated Depreciation	Construction Work in Progress
APS				
Generating Facilities:				
Palo Verde Units 1 and 3	29.1%	$ 1,877,846	$ (915,611)	$ 51,914
Palo Verde Unit 2 (see Note 9)	17.0%	665,994	(253,083)	15,816
Four Corners Units 4 and 5	15.0%	147,067	(83,525)	457
Navajo Generating Station Units 1, 2, and 3	14.0%	248,509	(117,922)	2,132
Cholla common facilities (a)	62.4%(b)	80,122	(47,134)	1,553
Transmission Facilities:				
ANPP500KV System	35.8%(b)	67,762	(27,898)	1,026
Navajo Southern System	31.4%(b)	27,044	(16,880)	1,576
Palo Verde – Yuma 500KV System	23.9%(b)	10,347	(4,545)	26
Four Corners Switchyards	27.5%(b)	2,852	(1,801)	–
Phoenix – Mead System	17.1%(b)	36,418	(2,723)	–
Palo Verde – Estrella 500KV System	55.5%(b)	72,613	(2,907)	841
Palo Verde – Southeast Valley Project	15.0%(b)	–	–	1,136
Harquahala	80.0%(b)	–	–	10
PINNACLE WEST ENERGY				
Generating Facilities:				
Silverhawk	75.0%	301,288	(6,954)	21

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at Cholla are jointly-owned.
(b) Weighted average of interests.

11. COMMITMENTS AND CONTINGENCIES

Palo Verde Nuclear Generating Station

Spent Nuclear Fuel and Waste Disposal

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

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is operating a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be

available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit. Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates it will incur $115 million (in 2004 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2004, APS had spent $11 million for on-site interim spent nuclear fuel storage. APS has recorded a regulatory asset of $11 million and is currently seeking recovery of these costs through future rates (see "APS General Rate Case; 2004 Settlement Agreement" in Note 3).

APS believes that scientific and financial aspects of the issues of spent nuclear fuel and low-level waste storage and disposal can be resolved satisfactorily. However, APS acknowledges that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which APS is less able to predict. APS expects to vigorously protect and pursue its rights related to this matter.

Nuclear Insurance

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $101 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $88 million, with an annual payment limitation of approximately $9 million.

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

Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2005 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $187 million in 2005; $90 million in 2006; $81 million in 2007; $66 million in 2008; $68 million in 2009 and $363 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts APS has for the supply of its coal supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016.

The following table summarizes the estimated take-or-pay commitments for the existing terms (dollars in millions):

	Estimated Years Ending December 31,					
	2005	2006	2007	2008	2009	Thereafter
Coal take-or-pay commitments (a)	$ 48	$ 48	$ 49	$ 42	$ 44	$ 311

(a) Total take-or-pay commitments are approximately $542 million. The total net present value of these commitments is approximately $389 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. APS' coal mine reclamation obligation was $61 million at December 31, 2004 and $60 million at December 31, 2003 and is included in deferred credits-other on the Consolidated Balance Sheets.

California Energy Market Issues and Refunds in the Pacific Northwest

FERC

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. The FERC is still considering the evidence and refund amounts have not yet been finalized. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it will be entitled to a net refund.

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present under market-based rates. State of California v. British Columbia Power Exchange et al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint was dismissed by the FERC and the State of California appealed the matter to the Ninth Circuit Court of Appeals. In an order issued September 9, 2004, the Ninth Circuit upheld the FERC's authority to permit market-based rates, but rejected the FERC's claim that it was without authority to consider retroactive refunds when a utility has not strictly adhered to the quarterly reporting requirements of the market-based rate system. On September 9, 2004, the Ninth Circuit remanded the case to the FERC for further proceedings. State of California ex rel. Bill Lockyer, Attorney General v. FERC, No. 02-73093. Several of the intervenors in this appeal filed a petition for rehearing of this decision on October 25, 2004. The outcome of the further proceedings cannot be predicted at this time.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ's conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Court of Appeals (Ninth Circuit). Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. After reviewing the matter, along with the data supplied by APS, the FERC staff moved to dismiss the claims against APS and to dismiss the proceeding. The motion to dismiss was granted by the FERC on January 22, 2004. Certain parties have sought rehearing of this order, and that request is pending.

California Civil Energy Market Litigation

The State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and California independent system operator markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California, which, after moving to state court, has been removed to the federal court for a second time. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867, U.S. District Court (Northern District) C-04-0519 SBA. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws.

The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS and numerous other PX participants. Cal PX v. The State of California, Superior Court in and for the County

of Sacramento, JCCP No. 4203. Various motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

Construction Program

Consolidated capital expenditures in 2005 are estimated to be (dollars in millions):

APS	$ 772
Pinnacle West Energy	7
SunCor	114
Other	8
Total	$ 901

Natural Gas Supply

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

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

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

Navajo Nation Litigation

In June 1999, the Navajo Nation served Salt River project with a lawsuit naming Salt River Project, several Peabody Coal Company entities (collectively, "Peabody"), Southern California Edison Company and other defendants, and citing various claims in connection with the renegotiations of the coal royalty and lease agreements under which Peabody mines coal for the Navajo Generating Station and the Mohave Generating Station. The Navajo Nation v. Peabody Holding Company, Inc., et al., United States District Court for the District of Columbia, CA-99-0469-EGS (the "D.C. Lawsuit"). APS is a 14% owner of the Navajo Generating Station, which, Salt River Project operates. The D.C. Lawsuit alleges, among other things, that the defendants obtained a favorable coal royalty rate by improperly influencing the outcome of a federal administrative process under which the royalty rate was to be adjusted. The suit seeks $600 million in damages, treble damages, punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands arising out of the (primary coal lease)." In July 2001, the court dismissed all claims against Salt River Project.

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

Litigation

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

12. ASSET RETIREMENT OBLIGATIONS

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets. The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term. Some of APS' transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such distribution and transmission assets. The asset retirement obligations associated with our non-regulated assets are immaterial.

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds in fixed income and domestic equity securities and classifies them as available for sale. The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Consolidated Balance Sheets at December 31, 2004 and December 31, 2003 (dollars in millions):

	December 31,	
	2004	2003
Trust fund assets – at cost		
Fixed income securities	$ 134	$ 124
Domestic stock	83	74
Total	$ 217	$ 198
Trust fund assets – at fair value		
Fixed income securities	$ 150	$ 140
Domestic stock	118	101
Total	$ 268	$ 241

The following schedule shows the change in our asset retirement obligations during the years ended December 31, 2004 and 2003 (dollars in millions):

	2004	2003
At beginning of year	$ 234	$ 219
Changes attributable to:		
Liabilities incurred	–	–
Liabilities settled	(1)	–
Accretion expense	17	15
Estimated cash flow revisions	2	–
At end of year	$ 252	$ 234

In accordance with SFAS No. 71, APS accrues for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2004, regulatory liabilities shown on Pinnacle West's Consolidated Balance Sheets included approximately $462 million of estimated future removal costs that are not considered legal obligations.

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following note presents quarterly financial information for 2004 and 2003. We are disclosing originally reported amounts and revised amounts in the first and second quarters of 2004 due to the adoption of FSP 106-2, which was implemented on June 30, 2004 (see Note 8) and in each period for the reclassification of NAC as discontinued operations (see Note 22).

Consolidated quarterly financial information for 2004 and 2003 is as follows (dollars in thousands, except per share amounts):

	2004 Quarter Ended				2004
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	$ 574,369	$ 722,686	$ 886,779	$ 734,718	$ 2,918,552
Operations and Maintenance	138,656	140,245	160,765	159,431	599,097
Operating Income	83,371	121,160	210,836	90,745	506,112
Income Taxes	15,627	44,027	58,900	11,283	129,837
Income from Continuing Operations	29,768	71,057	103,886	29,318	234,029
Net Income (a)	30,156	71,370	105,400	33,729	240,655
NAC Reclassifications (see Note 22):					
Operating Revenues	(8,024)	(10,803)	–	–	(18,827)
Operating Income	(443)	(1,950)	–	–	(2,393)
Income Taxes	(159)	(821)	–	–	(980)
Income from Continuing Operations	(247)	(1,104)	–	–	(1,351)
Medicare Subsidy Adoption (See Note 8):					
Operations and Maintenance	(1,270)	(1,270)	–	–	(2,540)
Operating Income	1,270	1,270	–	–	2,540
Income from Continuing Operations	1,270	1,270	–	–	2,540
Net Income	1,270	1,270	–	–	2,540
After NAC Reclassifications and Medicare Subsidy Adoption:					
Operating Revenues	566,345	711,883	886,779	734,718	2,899,725
Operations and Maintenance	137,386	138,975	160,765	159,431	596,557
Operating Income	84,198	120,480	210,836	90,745	506,259
Income Taxes	15,468	43,206	58,900	11,283	128,857
Income from Continuing Operations	30,791	71,223	103,886	29,318	235,218
Net Income (a) (b)	31,426	72,640	105,400	33,729	243,195

	2003 Quarter Ended				2003
	March 31,	June 30,	Sept. 30,	Dec. 31,	Total
As originally reported:					
Operating Revenues	$ 552,643	$ 683,302	$ 847,703	$ 734,204	$ 2,817,852
Operating Income	69,255	132,482	198,850	81,466	482,053
Income Taxes	12,754	35,248	50,528	7,030	105,560
Income from Continuing Operations	20,153	54,889	109,538	45,996	230,576
Net Income (a)	25,298	56,142	110,048	49,091	240,579
NAC Reclassifications (see Note 22):					
Operating Revenues	(11,382)	(19,637)	(16,701)	(10,638)	(58,358)
Operating Income	(3,675)	(1,347)	(1,489)	(1,600)	(8,111)
Income Taxes	(1,402)	(507)	(567)	(611)	(3,087)
Income from Continuing Operations	(2,167)	(783)	(878)	(945)	(4,773)
Reclassified:					
Operating Revenues	541,261	663,665	831,002	723,566	2,759,494
Operating Income	65,580	131,135	197,361	79,866	473,942
Income Taxes	11,352	34,741	49,961	6,419	102,473
Income from Continuing Operations	17,986	54,106	108,660	45,051	225,803
Net Income (a) (b)	25,298	56,142	110,048	49,091	240,579

(a) Includes income from discontinued operations at SunCor (see Note 22).
(b) Includes income (loss) from NAC's discontinued operations (see Note 22).

	2004 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (a):				
Income From Continuing Operations	$ 0.33	$ 0.78	$ 1.14	$ 0.32
Net Income	0.33	0.78	1.15	0.37
After NAC reclassification and Medicare subsidy adoption – Basic earnings per share (a):				
Income from Continuing Operations	0.34	0.78	1.14	0.32
Net Income	0.34	0.80	1.15	0.37
As originally reported – Diluted earnings per share (a):				
Income From Continuing Operations	0.33	0.78	1.14	0.32
Net Income	0.33	0.78	1.15	0.37
After NAC reclassification and Medicare subsidy adoption – Diluted earnings per share (a):				
Income From Continued Operations	0.34	0.78	1.14	0.32
Net Income	0.34	0.79	1.15	0.37

	2003 Quarter Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
As originally reported – Basic earnings per share (b):				
Income From Continuing Operations	$ 0.22	$ 0.60	$ 1.20	$ 0.50
Net Income	0.28	0.62	1.21	0.54
Reclassified – Basic earnings per share (b):				
Income From Continuing Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.62	1.21	0.54
As originally reported – Diluted earnings per share (b):				
Income From Continuing Operations	0.22	0.60	1.20	0.50
Net Income	0.28	0.61	1.20	0.54
Reclassified – Diluted earnings per share (b):				
Income From Continued Operations	0.20	0.59	1.19	0.49
Net Income	0.28	0.61	1.20	0.54

(a) The difference between originally reported and revised basic and diluted earnings per share related to the sale of NAC (see Note 22) and the adoption of the Medicare subsidy which changed reported amounts for the first and second quarter of 2004 (See Note 8). The earnings per share impact from the sale of NAC or the adoption of the Medicare subsidy did not change earnings per share by more than $0.02 in any given quarter in 2004.

(b) The difference between originally reported and reclassified basic and diluted earnings per share for income from continuing operations related to the sale of NAC (see Note 22). The earnings per share impact from the sale of NAC did not change earnings per share by more than $0.02 in any given quarter in 2003.

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents are reasonable estimates of their fair values at December 31, 2004 and 2003 due to their short maturities.

We hold investments in debt securities for purposes other than trading. We believe that the carrying amounts of these investments represent reasonable estimates of their fair values at December 31, 2004 and 2003 due to the short-term reset of interest rates.

We also hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2004 and 2003 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount. For further information, see disclosure of cost and fair value of APS' nuclear decommissioning trust fund assets in Note 12.

On December 31, 2004, the carrying value of our long-term debt (excluding capitalized lease obligations) was $3.19 billion, with an estimated fair value of $3.30 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $3.31 billion on December 31, 2003, with an estimated fair value of $3.46 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

15. EARNINGS PER SHARE

The following table presents earnings per weighted average common share outstanding for the years ended December 31, 2004, 2003 and 2002:

	2004	2003	2002
Basic earnings per share:			
Income from continuing operations	$ 2.57	$ 2.47	$ 2.79
Income (loss) from discontinued operations	0.09	0.17	(0.26)
Cumulative effect of change in accounting	–	–	(0.77)
Earnings per share – basic	$ 2.66	$ 2.64	$ 1.76
Diluted earnings per share:			
Income from continuing operations	$ 2.57	$ 2.47	$ 2.78
Income (loss) from discontinued operations	0.09	0.16	(0.25)
Cumulative effect of change in accounting	–	–	(0.77)
Earnings per share – diluted	$ 2.66	$ 2.63	$ 1.76

Dilutive stock options increased average common shares outstanding by approximately 135,000 shares in 2004, 140,000 shares in 2003 and 61,000 shares in 2002. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,532,473 shares in 2004, 91,405,134 shares in 2003 and 84,963,921 shares in 2002.

Options to purchase 1,058,616 shares of common stock were outstanding at December 31, 2004 but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 2,291,646 at December 31, 2003 and 1,629,958 at December 31, 2002.

16. STOCK-BASED COMPENSATION

Pinnacle West offers stock-based compensation plans for officers and key employees of the Company and our subsidiaries.

In May 2002, shareholders approved the 2002 Long-Term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. The Company has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than 1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per share not less than the fair market value of the common stock at the time of grant. The stock options vest over three years, unless certain performance criteria are met, which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan includes outstanding options but no new options will be granted under the plan. Options vested one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provided for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25.

In addition, see Note 2 for discussion of a new standard on share based payments (SFAS No. 123R).

Total stock-based compensation cost, including restricted stock, performance shares, stock options, and stock ownership incentives was $8 million in 2004, $6 million in 2003 and $5 million in 2002 for Pinnacle West, and $6 million in 2004, $3 million in 2003 and $3 million in 2002 for APS.

The following table is a summary of the status of outstanding stock options under our equity incentive plans as of December 31, 2004, 2003 and 2002 and changes during the years ending on those dates:

	2004 Shares	2004 Weighted Average Exercise Price	2003 Shares	2003 Weighted Average Exercise Price	2002 Shares	2002 Weighted Average Exercise Price
Outstanding at beginning of year	2,698,246	$ 38.56	2,185,129	$ 39.96	1,832,725	$ 39.52
Granted	37,580	37.85	621,875	32.29	603,900	38.37
Exercised	(372,205)	34.02	(62,366)	26.09	(163,381)	28.25
Forfeited	(87,498)	42.31	(46,392)	37.61	(88,115)	41.54
Outstanding at end of year	2,276,123	39.14	2,698,246	38.56	2,185,129	39.96
Options exercisable at year-end	1,859,340	40.59	1,787,622	40.35	1,155,357	39.66
Weighted average fair value of options granted during the year		$ 3.53		$ 7.37		$ 6.16

The following table summarizes information about our stock options at December 31, 2004:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
$23.39 – 28.07	4,750	$ 27.44	0.5	4,750	$ 27.44
28.07 – 32.75	515,344	32,24	7.8	129,706	32.10
32.75 – 37.42	138,863	34.72	4.4	138,863	34.72
37.42 – 42.10	693,482	38.83	5.9	662,337	38.87
42.10 – 46.78	923,684	43.95	5.4	923,684	43.95
	2,276,123			1,859,340	

The following table is a summary of the amount and weighted-average grant date fair value of stock compensation awards granted, other than options, during the years ended December 31, 2004, 2003 and 2002:

	2004 Shares	2004 Grant Price	2003 Shares	2003 Grant Price	2002 Shares	2002 Grant Price
Restricted stock	4,000	$ 37.68(a)	4,000	$ 32.20(a)	6,000	$ 38.84(a)
Performance share awards	215,285	37.85(b)	119,085	32.29(b)	115,975	38.37(b)
Stock ownership incentive awards	9,015	40.29(c)	–	–	–	–

(a) Restricted stock priced at the average of the high and low market price on the grant date.
(b) Performance shares priced at the closing market price on the grant date.
(c) Shares are based on estimated ownership of Pinnacle West common stock.

17. BUSINESS SEGMENTS

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

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

In 2004, our other segment includes a $35 million gain ($21 million after-tax) related to the sale of El Dorado's limited partnership interest in the Phoenix Suns. The other segment also includes activity related to APS Energy Services' non-commodity trading activities, as well as the parent company and other subsidiaries.

Financial data for the years ended December 31, 2004, 2003 and 2002 by business segments is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2004				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 2,035	$ 462	$ 360	$ 43	$ 2,900
Purchased power and fuel costs	568	382	–	–	950
Other operating expenses	685	34	290	34	1,043
Operating margin	782	46	70	9	907
Depreciation and amortization	384	11	6	–	401
Interest expense	169	8	2	–	179
Other expense/(income)	4	(2)	(5)	(34)	(37)
Pretax margin	225	29	67	43	364
Income taxes	74	11	27	17	129
Income from continuing operations	151	18	40	26	235
Income from discontinued operations – net of income taxes of $5 (see Note 22)	–	–	4	4	8
Net income	$ 151	$ 18	$ 44	$ 30	$ 243
Total assets	$ 8,674	$ 746	$ 454	$ 23	$ 9,897
Capital expenditures	$ 483	$ 34	$ 81	$ –	$ 598

	Business Segments for the Year Ended December 31, 2003				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,978	$ 392	$ 362	$ 27	$ 2,759
Purchased power and fuel costs	517	345	–	–	862
Other operating expenses	625	34	306	23	988
Operating margin	836	13	56	4	909
Depreciation and amortization	428	1	6	–	435
Interest expense	172	–	2	1	175
Other expense/(income)	(4)	–	(25)	–	(29)
Pretax margin	240	12	73	3	328
Income taxes	70	3	28	1	102
Income from continuing operations	170	9	45	2	226
Income from discontinued operations – net of income taxes of $10 (see Note 22)	–	–	10	5	15
Net income	$ 170	$ 9	$ 55	$ 7	$ 241
Total assets	$ 8,373	$ 680	$ 439	$ 27	$ 9,519
Capital expenditures	$ 686	$ 9	$ 72	$ –	$ 767

	Business Segments for the Year Ended December 31, 2002				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,890	$ 287	$ 201	$ 27	$ 2,405
Purchased power and fuel costs	377	155	–	–	532
Other operating expenses	659	34	185	22	900
Operating margin	854	98	16	5	973
Depreciation and amortization	416	2	4	–	422
Interest expense	141	–	2	–	143
Other expense/(income)	19	–	(7)	7	19
Pretax margin	278	96	17	(2)	389
Income taxes	108	38	7	(1)	152
Income (loss) from continuing operations	170	58	10	(1)	237
Income (loss) from discontinued operations – net of income taxes of $14 (see Note 22)	–	–	9	(31)	(22)
Cumulative effect of change in accounting for trading activities – net of income taxes of $43	–	(66)	–	–	(66)
Net income (loss)	$ 170	$ (8)	$ 19	$ (32)	$ 149
Capital expenditures	$ 893	$ 19	$ 72	$ –	$ 984

18. DERIVATIVE AND ENERGY TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal, emissions allowances and in interest rates. We manage risks associated with these market fluctuations by utilizing various instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge our exposure to changes in interest rates and to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. As of December 31, 2004, we hedged exposures to the price variability of the commodities for a maximum of eight years. The changes in market value of such contracts have a high correlation to price changes in the hedged transactions. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We recognize all derivatives, except those which receive a scope exception, as either assets or liabilities on the balance sheet and measure those instruments at fair value in accordance with SFAS No. 133, as amended by SFAS No. 149. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business receive the normal purchase and sales exception and are accounted for under the accrual method of accounting. Changes in the fair value of derivative instruments are recognized periodically in income unless certain hedge criteria are met. For cash flow hedges, changes in the fair value of the derivative are recognized in common stock equity (as a component of other comprehensive income (loss)). For fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item associated with the hedged risk are recognized in earnings. We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. We use fair value hedges to limit our exposure to changes in fair value of an asset or liability.

We assess hedge effectiveness both at inception and on a continuing basis. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income.

Both non-trading and trading derivatives that do not receive a scope exception are classified as assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets. Certain of our non-trading derivatives qualify for cash flow hedge accounting treatment. Non-trading derivatives, or any portion thereof that are not effective hedges, are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings.

All gains and losses (realized and unrealized) on trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. Trading contracts that do not meet the definition of a derivative are accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We net these book-outs, which reduces both revenues and purchased power and fuel costs in our Consolidated Statement of Income, but this does not impact our financial condition, net income or cash flows.

In November 2003, the FASB revised its derivative guidance in DIG Issue No. C15, "Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Effective January 1, 2004, the new guidance changed the criteria for the normal purchases and sales scope exception for electricity contracts. The implementation of this guidance did not have a material impact on our consolidated financial statements.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative.

Cash Flow Hedges

The changes in the fair value of our hedged positions included in the Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 are comprised of the following (dollars in thousands):

	2004	2003	2002
Gains/(losses) on the ineffective portion of derivatives qualifying for hedge accounting	$ (1,568)	$ 8,237	$ 9,763
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	185	181	(2,484)
Gains from the discontinuance of cash flow hedges	1,137	–	386

During the twelve months ending December 31, 2005, we estimate that a net gain of $44 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

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

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

The following table summarizes our assets and liabilities from risk management and trading activities at December 31, 2004 and 2003 (dollars in thousands):

	December 31, 2004				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	$ 45,220	$ 19,417	$ (19,191)	$ (12,000)	$ 33,446
Options and margin account	18,821	118	(8,879)	–	10,060
Marketing and trading:					
Mark-to-market	102,855	204,512	(68,008)	(132,683)	106,676
Emission allowances – at cost and margin account	–	294	(17,328)	(11,579)	(28,613)
Total	$ 166,896	$ 224,341	$ (113,406)	$ (156,262)	$ 121,569

	December 31, 2003				
	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated electricity:					
Mark-to-market	$ 44,079	$ 5,900	$ (47,268)	$ (3,028)	$ (317)
Options	–	12,101	–	–	12,101
Marketing and trading:					
Mark-to-market	53,551	116,363	(37,023)	(63,398)	69,493
Emission allowances – at cost	–	4,582	(8,464)	(16,304)	(20,186)
Total	$ 97,630	$ 138,946	$ (92,755)	$ (82,730)	$ 61,091

Cash or other assets may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is $1 million at December 31, 2004 and $1 million at December 31, 2003, and is included in other current assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is $18 million at December 31, 2004 and $12 million at December 31, 2003, and is included in other current liabilities on the Consolidated Balance Sheet.

Fair Value Hedges

On January 29, 2004, we entered into two fixed-for-floating interest rate swap transactions on our $300 million 6.4% Senior Notes. The purpose of these hedges is to protect against significant fluctuations in the fair value of our debt. Our interest rate swaps are considered to be fully effective with any resulting gains or losses on the derivative offset by a similar loss or gain amount on the underlying fair value of debt. The fair value of the interest rate swaps was $2.6 million at December 31, 2004 and is included in investments and other assets with the corresponding offset in long-term debt less current maturities on the Consolidated Balance Sheets.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 35% of Pinnacle West's $391 million of risk management and trading assets as of December 31, 2004. Our risk management process assesses and monitors the financial exposure of these and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities, local distribution companies and financial institutions. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition. In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 "Derivative Accounting" for a discussion of our credit valuation adjustment policy.

19. OTHER INCOME AND OTHER EXPENSE

The following table provides detail of other income and other expense for the years ended December 31, 2004, 2003 and 2002 (dollars in thousands):

	Year Ended December 31,		
	2004	2003	2002
Other income:			
Investment gains (a)	$ 38,256	$ 3,649	$ –
Interest income	7,470	4,412	4,332
SunCor non-operating income (b)	4,458	24,740	7,355
Asset sales	3,026	618	568
Miscellaneous	779	2,144	2,655
Total other income	$ 53,989	$ 35,563	$ 14,910
Other expense:			
Non-operating costs (c)	$ (15,524)	$ (14,959)	$ (12,958)
Asset sales	(1,382)	(1,522)	(6,472)
Investment losses (d)	–	–	(10,439)
Miscellaneous	(4,604)	(4,093)	(3,786)
Total other expense	$ (21,510)	$ (20,574)	$ (33,655)

(a) Primarily related to the gain on the sale of El Dorado's limited partnership interest in the Phoenix Suns in the second quarter of 2004 for $35 million ($21 million after tax).
(b) Primarily related to the sale at SunCor of a land interest and profit participation agreement in the fourth quarter of 2003 for $18 million. In 2002, SunCor received $2.5 million for the profit participation.
(c) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations).
(d) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002.

20. VARIABLE INTEREST ENTITIES

In 1986, APS entered into agreements with three separate VIE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. We are not the primary beneficiary of the Palo Verde VIEs and, accordingly, do not consolidate them.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2004, APS would have been required to assume approximately $250 million of debt and pay the equity participants approximately $192 million.

In the first quarter of 2004, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities" for all non-SPE contractual arrangements. SunCor has certain land development arrangements that are required to be consolidated under FIN No. 46R. The assets and non-controlling interests reflected in our Consolidated Balance Sheets related to these arrangements were approximately $34 million at December 31, 2004.

21. GUARANTEES

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2004 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 25	1	$ –	–
APS Energy Services	46	1	51	1
Total	$ 71		$ 51	

At December 31, 2004, we had entered into approximately $39 million of letters of credit which support various transmission and construction agreements. These letters of credit expire in 2005 and 2006. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required. At December 31, 2004, Pinnacle West has approximately $3 million of letters of credit related to workers' compensation expiring in 2006.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2004, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. In July 2004, $150 million of these letters of credit were renewed for a three-year term and expire in 2007. The remainder expire in 2005. APS has also entered into approximately $102 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2006. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

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

22. DISCONTINUED OPERATIONS

The following table provides a summary of SunCor and NAC income (loss) from discontinued operations (after income taxes) for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
SunCor	$ 4	$ 10	$ 9
NAC	4	5	(31)
Total income (loss) from discontinued operations	$ 8	$ 15	$ (22)

SunCor

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on Pinnacle West's Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations.

In the second quarter of 2002, SunCor sold a retail center, but maintained a continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, the after-tax gain of $6 million ($10 million pretax) recorded in operations in 2002 related to this property was reclassified as discontinued operations on our Consolidated Statements of Income. The income from discontinued operations in the year ended December 31, 2002 primarily reflects this sale.

In 2003, SunCor sold its water utility company, which resulted in an after-tax gain of $8 million ($14 million pretax). The amounts of the gain on the sale and operating income of the water utility company in 2003 and 2002 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income.

In the fourth quarter of 2003, SunCor sold a retail center, which resulted in an after-tax gain of $2 million ($3 million pretax). The gain on the sale and the operating income related to this property in 2003 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this retail center.

In 2004, SunCor sold commercial property, which resulted in an after-tax gain of $1 million ($2 million pretax). The gain on the sale and the operating income related to this property in 2004 are classified as discontinued operations on Pinnacle West's Consolidated Statements of Income. There were no prior-year operations related to this property.

The following table provides SunCor's revenue and income before income taxes (including the gains on disposals as noted above) related to properties classified as discontinued operations on Pinnacle West's Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	$ 11	$ 71	$ 35
Income before taxes	6	17	15

NAC

In July 2004, we entered into an agreement to sell our investment in NAC. The transaction closed on November 18, 2004 and resulted in a pre-tax gain of $4 million, which is classified as discontinued operations in 2004. El Dorado began consolidating the operations of NAC in the third quarter of 2002. All related revenues and expenses for NAC have been reclassified to discontinued operations for the years ended December 31, 2003 and 2002 on Pinnacle West's Consolidated Statements of Income.

The following table provides the revenue and income before taxes (including the gain on disposal as noted above) for El Dorado's investment in NAC that was classified as discontinued operations for the years ended December 31, 2004, 2003 and 2002 (dollars in millions):

	2004	2003	2002
Revenue	$ 31	$ 58	$ 35
Income (loss) before taxes	7	8	(50)

Percentage of Completion – NAC

Certain NAC contract revenues are accounted for under the percentage-of-completion method. Revenues are recognized based upon total costs incurred to date compared to total costs expected to be incurred for each contract. Revisions in contract revenue and cost estimates are reflected in the accounting period when known. Provisions are made for the full amounts of anticipated losses in the periods in which they are first determined. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions and final contract settlements, may result in revisions to costs and income, and are recognized in the period in which revisions are determined. Profit incentives are included in revenues when their realization is reasonably assured.

Contract costs include all direct material and labor costs and those indirect costs related to contract performance, such as indirect labor, supplies, tools, repairs and depreciation costs. General and administrative costs are charged to expense as incurred.

Assets and Liabilities Related to Discontinued Operations

Due to the sale of NAC, all NAC assets and liabilities have been reclassified to assets and liabilities related to discontinued operations on the Consolidated Balance Sheets at December 31, 2003 and are provided in the following table (dollars in thousands):

	2003
Cash	$ 5,867
Customer and other receivables	11,066
Net property, plant and equipment	5,404
Other	728
Assets related to discontinued operations	$ 23,065
Accounts payable	$ 10,406
Long-term debt less current maturities	800
Other	5,221
Liabilities related to discontinued operations	$ 16,427

CERTIFICATIONS

On June 18, 2004, in accordance with Section 303A.12 of the Listed Company Manual, our Chief Executive Officer certified to the New York Stock Exchange that he was not aware of any violation by the Company of NYSE corporate governance listing standards as of such date. In addition, on March 16, 2005, our Chief Executive Officer and Chief Financial Officer each filed a certification under Section 302 of the Sarbanes-Oxley Act (regarding the quality of the Company's public disclosure) as exhibits of the Company's Annual Report on Form 10-K for fiscal year 2004.

BOARD OF DIRECTORS

1. PAMELA GRANT (66) 1980* *Civic Leader* COMMITTEES: Audit; Corporate Governance; Human Resources 2. MARTHA O. HESSE (62) 1991 *Corporate Director* COMMITTEES: Audit, Chairman; Corporate Governance; Finance and Operating 3. THE REV. BILL JAMIESON, JR. (61) 1991 *President, Micah Institute, Asheville, North Carolina* COMMITTEES: Audit; Corporate Governance; Human Resources 4. ROY A. HERBERGER, JR. (62) 1992 *President Emeritus, Thunderbird, The Garvin School of International Management* COMMITTEES: Corporate Governance; Finance and Operating; Human Resources, Chairman 5. WILLIAM J. POST (54) 1994 *Chairman of the Board & Chief Executive Officer* COMMITTEE: Finance and Operating 6. HUMBERTO S. LOPEZ (59) 1995 *President, HSL Properties, Inc.* COMMITTEES: Audit; Corporate Governance; Human Resources 7. MICHAEL L. GALLAGHER (60) 1997 *Chairman Emeritus, Gallagher & Kennedy, P.A.* COMMITTEE: Finance and Operating, Chairman 8. BRUCE J. NORDSTROM (55) 1997 *Certified Public Accountant, Nordstrom and Associates, P.C.* COMMITTEES: Audit; Corporate Governance; Finance and Operating 9. JACK E. DAVIS (58) 1998 *President & Chief Operating Officer* COMMITTEE: Finance and Operating 10. WILLIAM L. STEWART (61) 1998 COMMITTEE: Finance and Operating 11. EDDIE BASHA (67) 1999 *Chairman of the Board, Bashas'* COMMITTEES: Audit; Corporate Governance; Human Resources 12. KATHRYN L. MUNRO (56) 1999 *Principal, BridgeWest L.L.C.* COMMITTEES: Audit; Corporate Governance, Chairman; Finance and Operating

** The year in which the individual first joined the Board of a Pinnacle West company.*

OFFICERS

Pinnacle West

William J. Post (54) 1973*
Chairman of the Board & Chief Executive Officer

Jack E. Davis (58) 1973
President & Chief Operating Officer

Donald E. Brandt (50) 2002
Executive Vice President & Chief Financial Officer

Robert S. Aiken (48) 1986
Vice President, Federal Affairs

Barbara M. Gomez (50) 1978
Vice President & Treasurer

Nancy C. Loftin (51) 1985
Vice President, General Counsel & Secretary

Martin L. Shultz (60) 1979
Vice President, Government Affairs

Arizona Public Service

William J. Post
Chairman of the Board

Jack E. Davis
President & Chief Executive Officer

Donald E. Brandt
Executive Vice President & Chief Financial Officer

Armando B. Flores (61) 1991
Executive Vice President, Corporate Business Services

James M. Levine (55) 1989
Executive Vice President, Generation

Steven M. Wheeler (56) 2001
Executive Vice President, Customer Service & Regulation

Gregg R. Overbeck (58) 1990
Senior Vice President, Nuclear Generation

Jan H. Bennett (57) 1967
Vice President, Customer Service

Ajit P. Bhatti (59) 1973
Vice President, Resource Planning

Dennis L. Brown (54) 1973
Vice President & Chief Information Officer

John R. Denman (62) 1964
Vice President, Fossil Generation

Edward Z. Fox (51) 1995
Vice President, Communications, Environment & Safety

Chris N. Froggatt (47) 1986
Vice President & Controller

Barbara M. Gomez
Vice President & Treasurer

David A. Hansen (45) 1980
Vice President, Power Marketing & Trading

Nancy C. Loftin
Vice President, General Counsel & Secretary

David Mauldin (55) 1990
Vice President, Nuclear Engineering & Support

Donald G. Robinson (51) 1978
Vice President, Planning

Pinnacle West Energy

James M. Levine
President & Chief Executive Officer

Donald E. Brandt
Chief Financial Officer

Ajoy K. Banerjee (59) 1999
Vice President, Construction & Operations

Warren C. Kotzmann (55) 1989
Vice President, Business & Corporate Services

SunCor Development

William J. Post
Chairman of the Board

John C. Ogden (59) 1972
Chief Executive Officer

Steven A. Betts (46) 2005
President

Duane S. Black (52) 1989
Executive Vice President & Chief Operating Officer

Jay T. Ellingson (56) 1992
Vice President, Development – Palm Valley

Margaret E. Kirch (55) 1988
Vice President, Commercial Development

Thomas A. Patrick (51) 1995
Vice President, Golf Operations

APS Energy Services

Vicki G. Sandler (48) 1982
President, APS Energy Services

El Dorado Investment

William J. Post
Chairman of the Board, President & Chief Executive Officer

** The year in which the individual was first employed within the Pinnacle West group of companies.*

SHAREHOLDER INFORMATION

Corporate Headquarters

400 North 5th Street
P.O. Box 53999
Phoenix, Arizona 85004
Main telephone number:
(602) 250-1000

Transfer Agent and Registrar

The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
(800) 457-2983
www.stockbny.com

Investor Relations Contacts

Rebecca L. Hickman,
Director, Investor Relations
Lisa Malagon, Manager
P.O. Box 53999 Station 9998
Phoenix, AZ 85072-3999
Telephone: (602) 250-5668
Fax: (602) 250-2789

Statistical Report

A detailed Statistical Report for Financial Analysis for 1999-2004 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

www.pinnaclewest.com

Annual Meeting of Shareholders

Wednesday, May 18, 2005 at 10:30 a.m.
Hyatt Regency
122 North 2nd Street
Phoenix, AZ

Stock Listing

Ticker symbol: PNW on New York Stock Exchange and Pacific Stock Exchange
Newspaper financial listings: PinWst

Statewide Association for Utility Investors

The Arizona Utility Investors Association represents the interests of investors in Arizona utilities. If interested, send your name and address to:

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, AZ 85067
(602) 257-9200
www.auia.org

Form 10-K

Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available (after March 16, 2005) to shareholders upon written request, without charge. Write: Office of the Secretary.

Corporate Governance Report

To view the Pinnacle West Corporate Governance Report please visit www.pinnaclewest.com.

Administrative Information

Company contact: (602) 250-5511
shareholderdept@pinnaclewest.com

Investors Advantage Plan and Shareholder Account Information

Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling The Bank of New York at (800) 457-2983, at the Bank's Web site – www.stockbny.com or by writing to:

The Bank of New York
Shareholder Relations Department
P.O. Box 11258
Church Street Station
New York, NY 10286
(800) 457-2983

printed on recycled paper

Important notice to Shareholders:

Pinnacle West posts quarterly results and other important information on its web site (www.pinnaclewest.com). If you would like to receive news by regular mail, fax or e-mail, let us know by mail or phone at the addresses and numbers listed on page 90. Also, let us know if you would like to be kept abreast of legislative and regulatory activities at the state and federal levels that could impact investor-owned utilities.

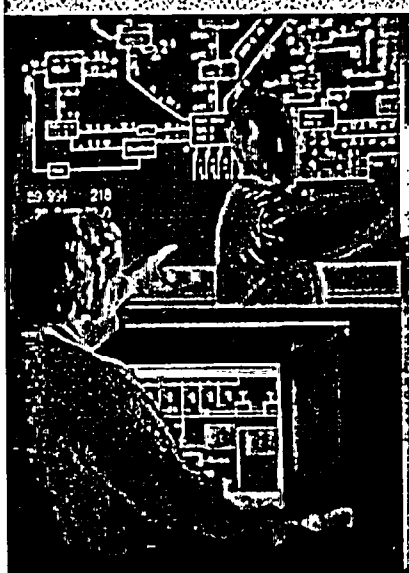
Design: Campbell Fisher Design www.thinkcfd.com

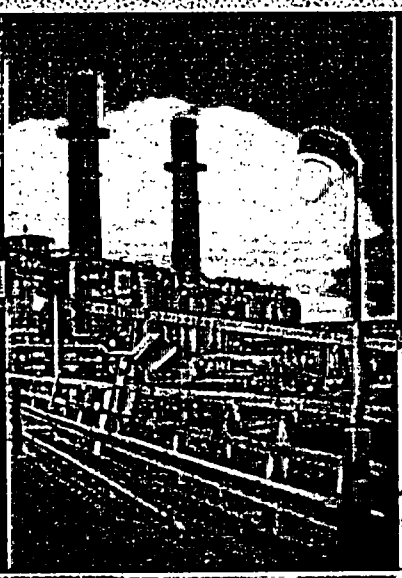
WWW.PINNACLEWEST.COM

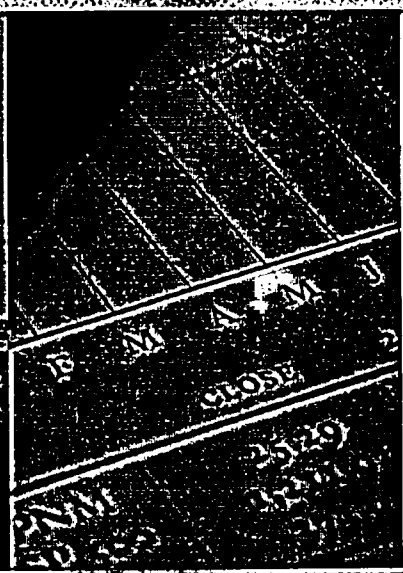
PINNACLE WEST
CAPITAL CORPORATION

PNM RESOURCES

Measured Growth







2004 SUMMARY ANNUAL REPORT

Contents

Investor Highlights

In thousands, except per share amounts and ratios

	2004	2003	Percentage Change	5-Year Annual Growth Rate
Financial Data				
Operating Revenues	$1,604,792	$1,455,653	10.25%	7.43%
Operating Expenses	$1,491,894	$1,337,061	11.58%	8.30%
Net Earnings Available for Common Stock	$87,686	$95,173	(7.87)%	1.21%
Retained Earnings	$550,566	$503,069	9.44%	19.30%
Common Share Data				
Earnings (Basic) per Share as Reported	$1.45	$1.60	(9.38)%	1.59%
Earnings (Basic) per Share Ongoing (1)	$1.45	$1.31	10.69%	2.53%
Earnings (Diluted) per Share as Reported	$1.43	$1.58	(9.49)%	1.31%
Earnings (Diluted) per Share Ongoing (1)	$1.43	$1.30	10.00%	2.24%
Book Value per Share	$18.20	$18.07	0.72%	4.78%
Dividends Paid per Share	$0.63	$0.61	3.28%	3.52%
Market Price per Share (Post 3-for-2 Stock Split June 2004):				
High	$26.11	$19.64	32.94%	12.75%
Low	$18.70	$12.63	48.06%	13.56%
Close at Year-End	$25.29	$18.73	35.02%	18.49%
Average Shares Outstanding	60,414	59,621	1.33%	(0.37)%
Financial Ratios				
Market-to-Book Ratio at Year-End	1.39	1.04	34.06%	13.08%
Price Earnings Ratio at Year-End	17.44	11.71	48.99%	16.63%
Return on Average Common Equity	8.07%	9.28%	(13.04)%	(3.09)%
Dividend Yield on Market Price at Year-End	2.49%	3.26%	(23.51)%	(12.63)%

(1) Ongoing EPS includes adjustments for net one-time gains and charges of $0.28 per diluted share for 2003 and $0.14 per diluted share for 2002. 2002 GAAP EPS was $1.07 per diluted share. No one-time gains or losses occurred in 2004.

We're growing. We're growing our generation capacity, our customer base and our long-term power contracts. Revenues are up, expenses are down and it's clear that PNM Resources' strategy is working. Led by a team of seasoned professionals, we're expanding our utility business into new geographic markets through the acquisition of TNP Enterprises. Fueled by increased long-term contracts, we are expanding our wholesale generation portfolio to meet demand. Joint ownership of a new natural gas-fired, combined-cycle power plant will help us serve our wholesale power business. Our customers and shareholders can rest assured that our focus is not on growth for growth's sake, but on smart, strategic business solutions and opportunities that result in growth. *Measured growth.*

Our Report

From the Chairman, President & CEO

Dear fellow shareholders, PNM Resources continues to grow. It is careful and methodical. It is not growth for growth's sake, but the result of executing our strategy and vision to Build America's Best Merchant Utility. We firmly believe this will increase shareholder value, and 2004 proved this true.

This past year has been nothing short of exciting as we announced the acquisition of another energy company. A company that not only fits our strategic growth plans, but also opens the door to market expansion into Texas. Additionally, we have purchased a share in a natural gas-fired, combined-cycle power plant that will help us serve our growing wholesale power business.

JEFF STERBA
Chairman, President & CEO

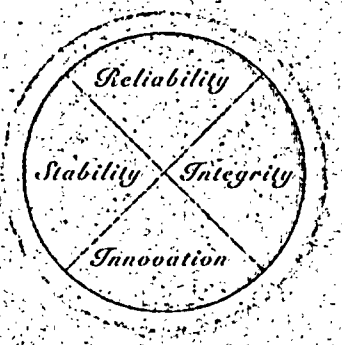
We have built our business on the cornerstones of reliability, stability, integrity and innovation. Combining these simple, yet powerful business fundamentals with a solid growth strategy has resulted in another successful year in 2004.

Throughout the year, we concentrated on the strategic direction of the company, while not losing sight of our efforts to improve customer satisfaction, operational excellence and process improvement. All in all, it was a very successful year for PNM Resources, and our shareholders benefited from that success.

Total revenues for PNM Resources topped $1.60 billion in 2004, growing from $1.46 billion in 2003, while diluted earnings per share of common stock were $1.43. Adjusted for the 3-for-2 stock split announced in

"We have built our business on the cornerstones of reliability, stability, integrity and innovation. Combining these simple, yet powerful, business fundamentals with a solid growth strategy has resulted in another successful year in 2004."

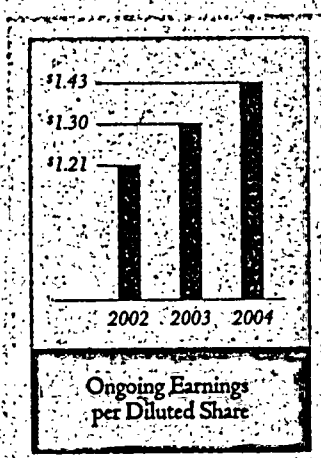
JEFF STERBA
Chairman, President & CEO



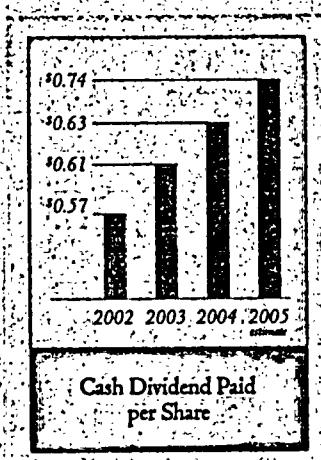
May 2004, that compares with $1.58 in 2003. Earnings from ongoing operations, not including one-time gains or losses, were $1.43 per share, compared with $1.30 per share ($1.95 before the stock split) in 2003. Three years ago we said that our goal was to generate 5 percent to 6 percent annualized earnings growth. Actually, we have delivered nearly 9 percent growth in ongoing earnings per share during the past three years. The bottom line for you was a healthy increase in the value of your investment.

Because of our earnings profile of growth and stability, the PNM Resources Board of Directors raised the common stock dividend twice in 2004 to an annual rate of $0.74 per share – a 20.7 percent increase. Previously, the Board had targeted a payout ratio of 50 percent to 60 percent of utility earnings. However, our stable and successful approach to competitive wholesale markets caused the Board to revise the policy to 50 percent to 60 percent of consolidated earnings.

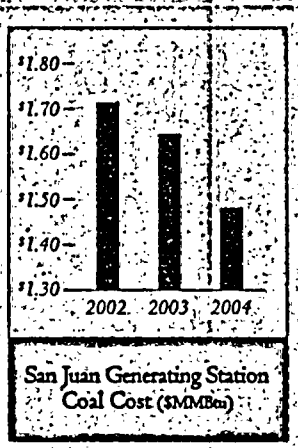
Our business and financial success was rewarded with stock price appreciation of 35 percent for 2004, compared with 8.1 percent for the S&P Mid-Cap Electric Utility Index and 9 percent for the broader S&P 500 Index. Despite this excellent performance, our efforts are not directed at short-term success. We are in it for the long haul, and we are motivated to deliver on our investors' expectations for long-term business and financial success.

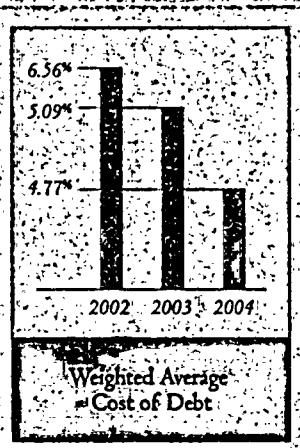


Ongoing Earnings per Diluted Share



Cash Dividend Paid per Share





GROWING A MERCHANT UTILITY

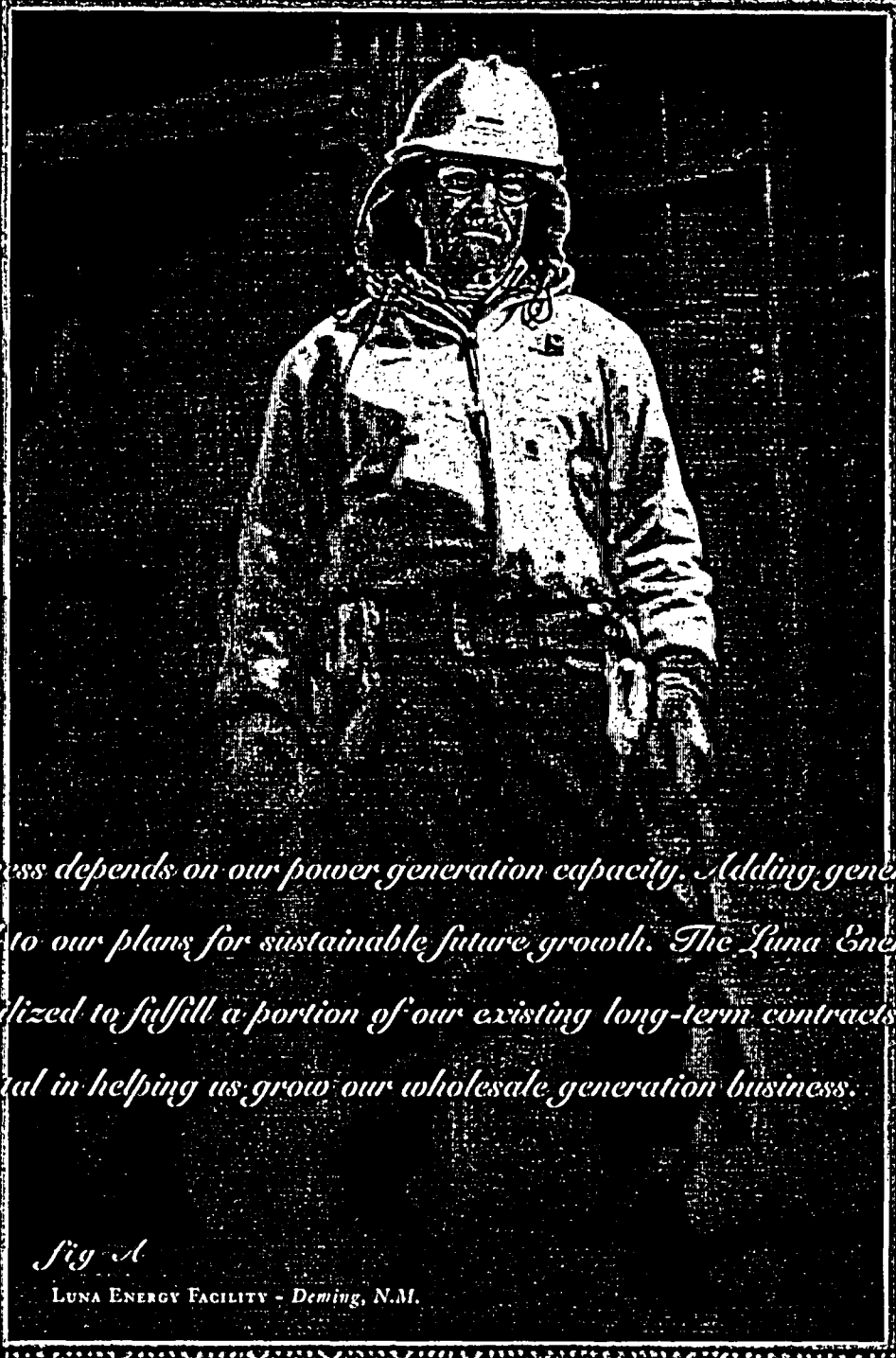
Over the years, we've discussed our distinctive merchant utility business model. Our foundation is an operationally sound, regulated electric and gas utility that delivers stable earnings. It is supplemented with our competitive business line. This provides an effective blend of regulated and competitive business lines for stability and growth. Those factors balance risk and provide multiple opportunities for expansion.

IMPLEMENTING OUR VISION

In July we announced an agreement to acquire TNP Enterprises, a Fort Worth-based energy holding company and parent company of Texas-New Mexico Power, or TNMP, and First Choice Power, a retail energy provider in Texas. TNMP is an electric transmission and distribution company in Texas and a fully integrated utility in southern New Mexico.

"Our successful wholesale power marketing business will continue to be a growth engine for PNM Resources. We will continue to produce measured growth through long-term power contracts and by adding right-priced, strategically located generation and transmission assets."

HUGH SMITH
Senior Vice President of Energy Resources



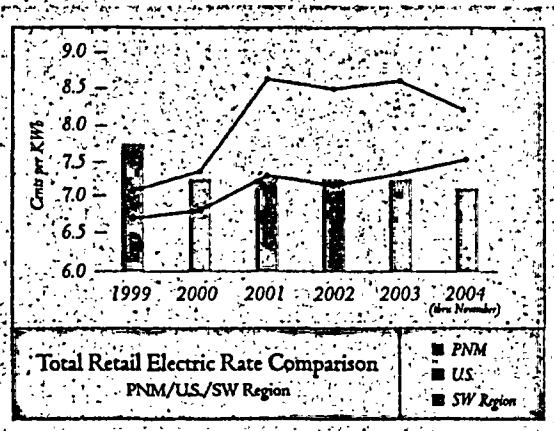
Our business depends on our power generation capacity. Adding generation assets is critical to our plans for sustainable future growth. The Luna Energy Facility will be utilized to fulfill a portion of our existing long-term contracts and will be instrumental in helping us grow our wholesale generation business.

Fig A

LUNA ENERGY FACILITY - *Deming, N.M.*

fig B
Southwest New Mexico

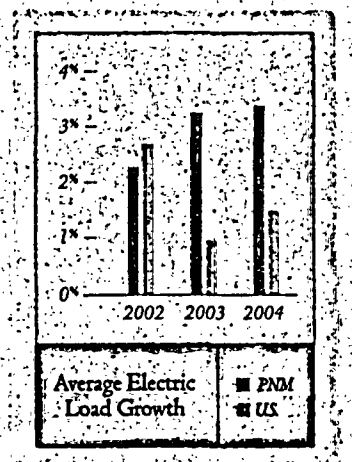
PNM continues to rank in the top quartile for all categories of electric reliability, as measured in a national survey conducted by the Edison Electric Institute. While we've maintained top-ranked electric dependability, we've reduced electric prices by 7 percent since 1991, moving our rates below the national average and almost 13 percent below the regional average.



Source: U.S. Energy Information Administration

TNMP's well-run delivery operations in both states will complement and strengthen our utility operations in New Mexico. Our experience and expertise in the competitive electric wholesale market will help First Choice Power expand its reach into the competitive electric retail business in Texas and provide us avenues for future growth. We expect the acquisition to be at least 10 percent accretive to current earnings per share and 20 percent accretive to free cash flow in the first full year after closing.

In November we purchased a one-third interest – 190 megawatts – in a state-of-the-art power plant near Deming, N.M. The Luna Energy Facility will be utilized to fulfill a portion of our existing long-term contracts and will be instrumental in helping us grow our wholesale generation business. The plant has the ability to deliver electricity to major market hubs in the Southwest, and we expect its first full year of operation to be 3 percent accretive to PNM Resources' earnings and cash flow.

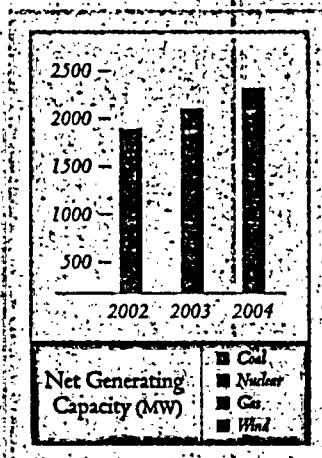


Source: U.S. Energy Information Administration

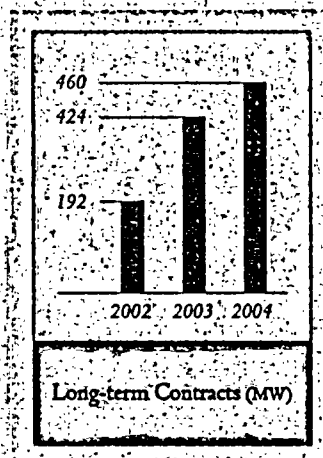
"Both PNM Resources and TNP Enterprises bring unique strengths to the combination and provide us with diverse skills and talents. To benefit from those strengths, our integration team is identifying the best processes and systems of each company. This approach will help us achieve our goal to deliver the best results possible to all of our stakeholders."

ALICE COBB

Senior Vice President & Chief Administrative Officer



Gas includes Delta Person lease and Luna Energy Facility



With the share of the Luna plant, PNM Resources and its principal subsidiary, PNM, will have added about 600 megawatts to the generation portfolio since 2002. In recent years, PNM has signed long-term contracts to supply power to eight entities increasing total long-term contracts to 460 MW. The addition of the Luna plant further strengthens the merchant side of the business as we follow our strategy to diversify our generation portfolio.

We're not done. We will continue to look for right-priced assets that provide an opportunity to expand our business, while maintaining the balance between wholesale activities and our core utility business.

LEADING ENVIRONMENTAL SUSTAINABILITY

As we grow, so does our responsibility as a corporate citizen. Protecting and preserving the environment is not simply an obligation, it's our commitment to present and future generations.

"At PNM Resources, integrity is everyone's business. We operate our business with the highest level of ethical conduct in our daily business practices. That means 'doing the right thing' is every employee's obligation. Moreover, that commitment extends beyond the level of compliance required by various laws and regulations – 'doing the right thing' – is engrained in our culture. Our record of ethical leadership is reflected in our commitment to employees, shareholders, the communities we serve and the environment."

PATRICK ORTIZ
Senior Vice President, General Counsel & Secretary

Helping others in the communities we serve is not a corporate commitment, it's our culture of giving that is embraced by our employees. More than 300 PNM Resources employees and retirees volunteered their time and skills to help make a dream come true for a family through this Habitat for Humanity project.

fig 6

HABITAT FOR HUMANITY HOME - *Albuquerque, N.M.*

The PNM Sky Blue™ program is one of the nation's most successful renewable energy programs. More than 6,600 residential and 300 business customers signed up in 2004 to support PNM Resources' first venture into renewable power. This level of growth is unprecedented for utilities with similar renewable programs.

fig 8

New Mexico Wind Energy Center - *(near) House, N.M.*

We have established five-year goals that will help us achieve long-term environmental sustainability. In many instances, these goals reduce emissions below levels allowed by law or regulations. We also are reducing some emissions in *advance* of new regulations.

We, as a society, must prepare to succeed in a carbon-constrained world by reducing carbon emissions. For PNM Resources, the key is to do that in a way that minimizes the economic impact on our business, customers and shareholders. During the next five years, we are committed to reducing carbon intensity by 7 percent.

Five-year environmental goals

Air

Compared with 2002, on a per megawatt-hour basis, we will emit 15 percent less nitrogen oxide (NO_X), 15 percent less sulfur dioxide (SO_2) and 7.5 percent fewer particulates. Compared to 2003, we will emit 7 percent less carbon dioxide (CO_2) or equivalents per MWh[1].

Water

Our current generation portfolio will use 15 percent to 20 percent less fresh water per MWh than it did in 2002. When new generating plants are added to our portfolio, either the new plant's per MWh fresh water usage will be at least 20 percent lower than the 2002 portfolio average, or fresh water usage elsewhere in the generation portfolio will be reduced to provide an offset and achieve the same portfoliowide per MWh fresh water usage reduction.

Renewables

Become known, through our actions, as a national utility leader in the promotion and provision of renewable resources.

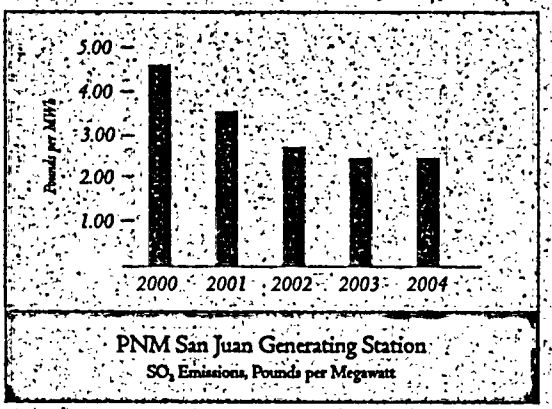
Waste

We will define waste streams generated by our company and implement plans to reduce waste by 15 percent.

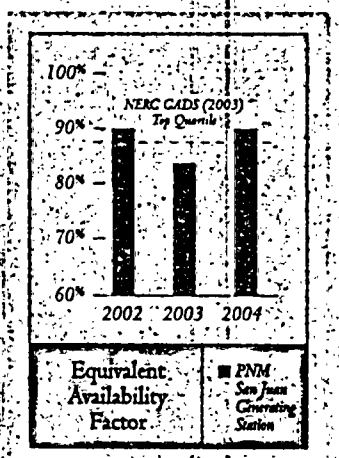
[1] Because of new federal reporting guidelines, PNM Resources changed its CO_2 calculation methodology in 2003. Using 2002 as a baseline year would create a false impression of CO_2 reduction, so PNM Resources has adopted 2003 as the baseline year.

"PNM provides top tier electric reliability, along with electric and gas customer service that in many areas meets or exceeds national averages. We have attained this quality of customer service by investing more than $500 million in our electric and gas systems over the last five years. Achieving high national ratings for system reliability and customer service results from the vision, dedication, innovation and effort of hundreds of employees across many PNM utility organizations."

EDDIE PADILLA
Senior Vice President of Customer & Delivery Services



Living in the Southwest, we have a deep and abiding concern about water quality and quantity. We must do our part to ensure water is available to support population and economic growth. For example, the Luna Energy Facility will utilize high-tech environmental control systems and rely on treated effluent for one-third of its water supply. The Luna facility will help us meet our environmental goal to reduce fresh water use by at least 20 percent less per megawatt than the 2002 portfolio average.



In addition, we - along with eight other owners - plan to invest in the San Juan Generating Station to take its already aggressive emission removal program to a whole new level. Over the next five years, new technology will be installed at the plant to reduce mercury, particulate matter, NO_X and SO_2 emissions.

"Our new environmental sustainability policy was crafted to move PNM Resources to a new level of stewardship, in which we become a community and industry leader by setting examples of responsible environmental behavior and supporting public policy. It guides us to balance economic, environmental and societal needs in every business decision we make and every action we take. To continue to increase shareholder value, PNM Resources must consider the long-term impact its business decisions will have on society and on the environment."

BILL REAL
Senior Vice President of Public Policy

Protecting and preserving the environment, wildlife and our natural resources is our commitment to present and future generations. PNM was an active partner in the development of a fish passage for endangered species on the San Juan River near the PNM San Juan Generating Station.

fig F

SAN JUAN RIVER - *(near) Farmington, N.M.*

In 2004 state regulators approved a $22 million natural gas delivery rate increase to return our gas business to profitability. Additionally, we entered into an agreement to transport natural gas to two power plants operated by the city of Farmington, N.M., which we expect will produce about $550,000 in annual revenues.

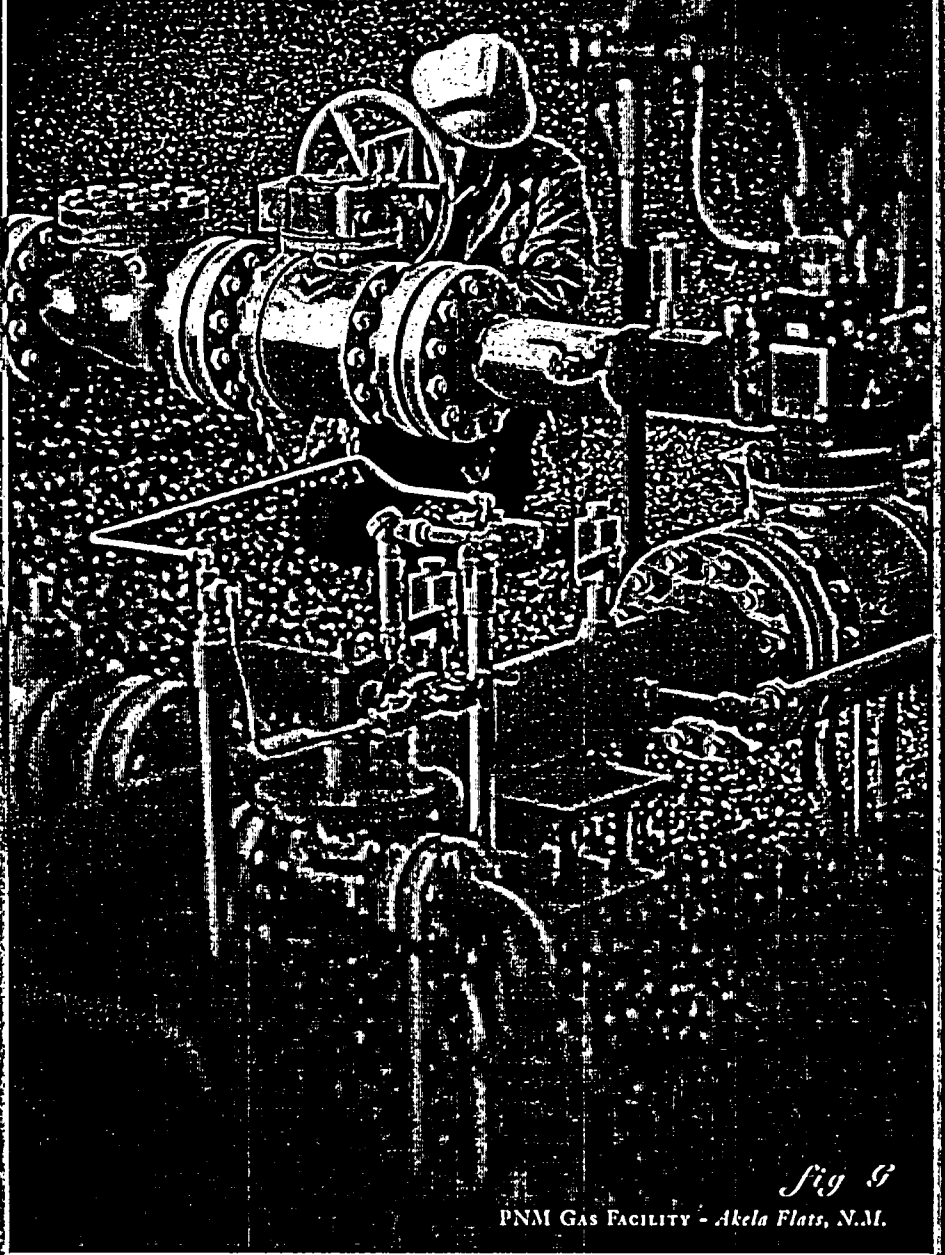
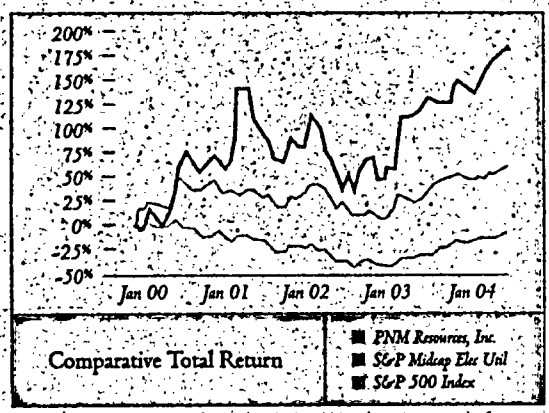


fig 6

PNM Gas Facility - *Akela Flats, N.M.*



"We're not just getting bigger; we're getting better."

JEFF STERBA

DELIVERING MEASURED GROWTH

By almost any measure, 2004 was a successful year for PNM Resources. Most of all, we were successful in our effort to grow shareholder value by controlling costs and improving productivity, coupled with a wholehearted commitment to meeting the needs and exceeding the expectations of our customers.

We're not just getting bigger; we're getting better. It is growth with a purpose. It is growth that serves customers and supports employees. It is growth that preserves the environment while rewarding shareholders. It is measured growth.

Jeff Sterba *Chairman, President & CEO of PNM Resources*

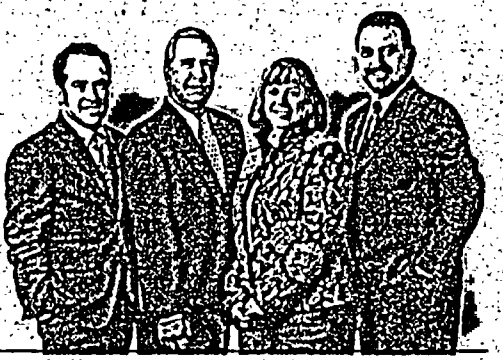
"We continue to expand our business in a way that allows us to grow earnings and cash flows while maintaining our balance sheet strength to sustain growth well into the future. That is our commitment to our customers, employees, creditors and shareholders."

JOHN LOYACK

Senior Vice President & Chief Financial Officer

Board of Directors

PNM Resources Inc.



Audit and Ethics Committee

R. Martin Chavez, Ph.D., *Managing Director, Goldman Sachs*, Age 41, Director since 2001

Robert G. Armstrong, *President of Armstrong Energy Corporation*, Age 58, Director since 1991

Julie A. Dobson, *Chairman of TeleBright Corporation*, Age 48, Director since 2002

Adelmo E. Archuleta, *President and Chief Executive Officer of Molzen-Corbin & Associates*, Age 54, Director since 2003

Human Resource and Compensation

Robert M. Price, *President of PSV Inc.*, Age 74, Director since 1992

Bonnie S. Reitz, *Owner/Founder, InsideOut...Culture to Customer*, Age 52, Director since 2002

Adelmo E. Archuleta, *President and Chief Executive Officer of Molzen-Corbin & Associates*, Age 54, Director since 2003

Manuel T. Pacheco, Ph.D., *President Emeritus, University of Missouri System*, Age 63, Director since 2001

Finance Committee

R. Martin Chavez, Ph.D., *Managing Director, Goldman Sachs*, Age 41, Director since 2001

Julie A. Dobson, *Chairman of TeleBright Corporation*, Age 48, Director since 2002

Joan B. Woodard, Ph.D., *Executive Vice President and Deputy Director for Sandia National Laboratories*, Age 52, Director since 2003

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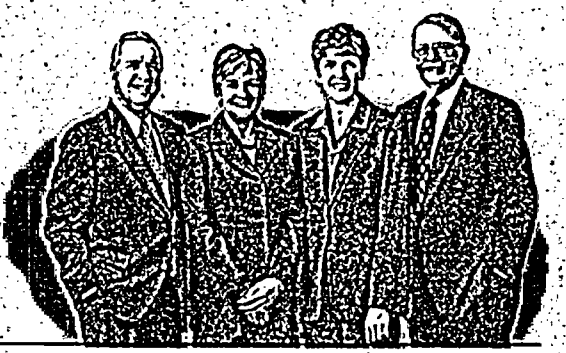


Governance and Public Policy Committee

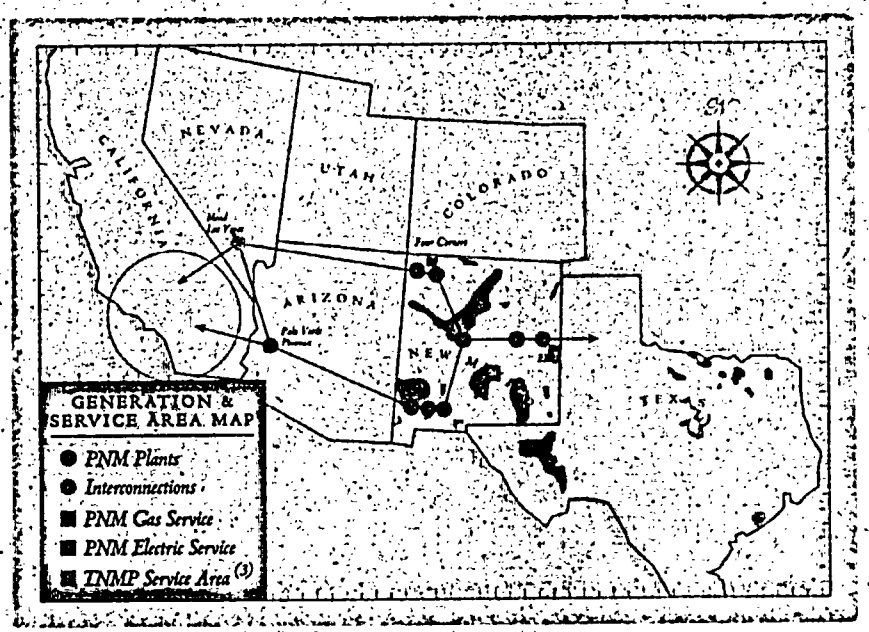
Robert G. Armstrong, *President of Armstrong Energy Corporation*, Age 58, Director since 1991

Bonnie S. Reitz, *Owner/Founder, InsideOut...Culture to Customer*, Age 52, Director since 2002

Joan B. Woodard, Ph.D., *Executive Vice President and Deputy Director for Sandia National Laboratories*, Age 52, Director since 2003

Manuel T. Pacheco, Ph.D., *President Emeritus, University of Missouri System*, Age 63, Director since 2001

Financial Contents



(3) Proposed aquisition announced July 2004.

On June 2, 2004, the Company submitted the required annual written certification to the NYSE to comply with Section 303A.12(a) of the NYSE Listed Company Manual. There were no qualifications to the certification. In addition, the Company has filed with the SEC, as exhibits to its Annual Report on Form 10-K filed on March 1, 2005, the Sarbanes-Oxley Act Section 302 certifications regarding the quality of the Company's public disclosure.

Selected Financial Data

PNM Resources, Inc. and Subsidiaries

(In thousands except per share amounts and ratios)	2004	2003	PERCENTAGE CHANGE	5-YEAR ANNUAL GROWTH RATE
Electric Retail Operations Statistics				
Total Electric Retail Energy Sales (KWh in thousands)	7,471,491	7,298,483	2.37%	1.89%
Total Electric Retail Revenue	$540,085	$541,011	(0.17)%	0.55%
Electric Retail Customers at Year-End	412,024	401,608	2.59%	2.66%
Electric Transmission Revenue	$18,327	$19,453	(5.79)%	3.38%
Wholesale Operations Statistics				
Total Energy Sales (MWh)	11,368,084	11,542,204	(1.51)%	3.07%
Total Wholesale Revenue	$554,634	$536,611	3.36%	11.29%
Total Electric Revenues	$1,113,046	$1,097,075	1.46%	5.15%
Gas Utility Operating Statistics				
Total Gas Throughput (Decatherms in thousands)	99,749	94,977	5.02%	1.57%
Total Gas Revenue	$490,921	$358,267	37.03%	14.75%
Gas Utility Customers at Year-End	468,572	458,818	2.13%	1.91%
Generation Statistics				
Coincidental Peak Demand - KW	1,655,000	1,661,000	(0.36)%	5.09%
Average Fuel Cost per Million BTU	$1.3751	$1.4120	(2.61)%	0.87%
Degree Days				
Heating	4,043	3,692	9.51%	1.42%
Cooling	1,304	1,671	(21.96)%	3.13%
Number of Employees	2,623	2,637	(0.53)%	(0.33)%

The condensed financial statements in this summary annual report were derived from the consolidated financial statements that appear in PNM Resources, Inc's Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 1, 2005. Copies of the Form 10-K may be obtained by calling PNM Resources Shareholder Services at 1-800-545-4425 or visiting pnmresources.com.

Corporate Information

PNM Resources, Inc. and Subsidiaries

THE COMPANY

We are an investor-owned holding company of energy and energy-related companies and were incorporated in the State of New Mexico on March 3, 2000. Our principal subsidiary, Public Service Company of New Mexico, or PNM, was incorporated in the State of New Mexico on May 9, 1917. PNM is a public utility primarily engaged in the generation, transmission, distribution, sale and marketing of electricity and in the transmission, distribution and sale of natural gas within the State of New Mexico. The business of PNM constitutes substantially all of the business of PNM Resources, Inc. and its subsidiaries. Our principal business segments are utility operations, wholesale operations and corporate and other. Utility operations include electric services and gas services. Electric services consist of the distribution, transmission and generation of electricity for retail electric customers in New Mexico. Gas services include the transportation and distribution of natural gas to end-users. Our wholesale operations consist of the generation and sale of electricity into the wholesale market based on three product lines, which are long-term contracts, forward sales and short-term sales.

On July 25, 2004, the Company announced the proposed $1.024 billion acquisition of TNP Enterprises, including its principal subsidiaries, Texas-New Mexico Power, or TNMP, and First Choice Power. The Company expects the proposed acquisition to be accretive to its earnings and free cash flow in the first full year after closing, which is expected in the second quarter of 2005.

Safe Harbor Statement under the Private Securities Litigation Reform Act of 1995

Statements made in this Summary Annual Report and documents the Company files with the SEC that relate to future events or the Company's expectations, projections, estimates, intentions, goals, targets and strategies, both with respect to the Company and with respect to the proposed acquisition of TNP Enterprises Inc., are made pursuant to the Private Securities Litigation Reform Act of 1995. You are cautioned that all forward-looking statements are based upon current expectations and estimates and the Company assumes no obligation to update this information. Because actual results may differ materially from those expressed or implied by the forward-looking statements, PNM Resources cautions you not to place undue reliance on these statements. Many factors could cause actual results to differ, and will affect the Company's future financial condition, cash flow and operating results. These factors include risks and uncertainties relating to the receipt of regulatory approvals of the proposed acquisition of TNP Enterprises Inc., the risks that the businesses will not be integrated successfully, the risk that the benefits of the acquisition will not be fully realized or will take longer to realize than expected, disruption from the proposed acquisition making it more difficult to maintain relationships with customers, employees, suppliers or other third parties, conditions in the financial markets relevant to the proposed acquisition, interest rates, weather, water supply, fuel costs, availability of fuel supplies, risk management and commodity risk transactions, seasonality and other changes in supply and demand in the market for electric power, wholesale power prices, market liquidity, the competitive environment in the electric and natural gas industries, the performance of generating units and transmission system, the ability of the Company to secure long-term power sales, the risks associated with completion of the construction of Luna Energy Facility, including construction delays and unanticipated cost overruns, state and federal regulatory and legislative decisions and actions, the outcome of legal proceedings, changes in applicable accounting principles and the performance of state, regional and national economies. For a detailed discussion of the important factors that affect PNM Resources and that could cause actual results to differ from those expressed or implied by the Company's forward-looking statements, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's current and future Annual Reports on Form 10-K and Quarterly Reports on Form 10-Q and the Company's current and future Current Reports on Form 8-K, filed with the SEC.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PNM Resources, Inc. and subsidiaries ("the Company") is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a – 15(f) under the Securities Exchange Act of 1934, as amended.

Management assessed the effectiveness of the Company's internal control over financial reporting based on the Internal Control – Integrated Framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment performed, management concludes that the Company's internal control over financial reporting was effective as of December 31, 2004.

Deloitte & Touche LLP, an independent registered public accounting firm, has issued an attestation report on management's assessment of internal control over financial reporting, which is included in our Annual Report on Form 10-K.

JEFFRY STERBA
Chairman, President & Chief Executive Officer

JOHN R. LOYACK
Senior Vice President & Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of PNM Resources, Inc.

We have audited the consolidated balance sheets and consolidated statements of capitalization of PNM Resources, Inc. and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of earnings, retained earnings, comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2004. We also have audited management's assessment of the effectiveness of the Company's internal control over financial reporting and the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. Such consolidated financial statements, management's assessment of the effectiveness of the Company's internal control over financial reporting and our reports thereon dated February 25, 2005, expressing unqualified opinions (which are not included herein) and including explanatory paragraphs regarding the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003 and the change in actuarial valuation measurement date for the pension plan and other post-retirement benefits from September 30 to December 31, are included in the Company's Annual Report on Form 10-K. The accompanying condensed consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on such condensed consolidated financial statements in relation to the complete consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated balance sheets as of December 31, 2004 and 2003, and the related condensed consolidated statements of earnings and of cash flows for each of the three years in the period ended December 31, 2004, is fairly stated in all material respects in relation to the basic consolidated financial statements from which it has been derived.

DELOITTE & TOUCHE LLP
San Francisco, California
February 25, 2005

Condensed Consolidated Statements of Earnings

PNM Resources, Inc. and Subsidiaries

(In thousands except per share amounts and ratios)	YEAR ENDED DECEMBER 31, 2004	2003	2002
Operating Revenues			
Electric	$1,113,046	$1,097,075	$839,884
Gas	490,921	358,267	277,406
Other	825	311	1,404
Total operating revenues	1,604,792	1,455,653	1,118,694
Operating Expenses			
Cost of energy sold	945,309	802,670	499,751
Other operations and maintenance expense	373,695	359,360	359,629
Depreciation and amortization	102,221	115,649	102,409
Taxes, other than income taxes	34,607	31,310	34,244
Income taxes	36,062	28,072	20,887
Total operating expenses	1,491,894	1,337,061	1,016,920
Operating income	112,898	118,592	101,774
Other Income and Deductions			
Other income and deductions	39,920	6,552	36,054
Income tax (expense) benefit	(13,185)	183	(12,144)
Net other income and deductions	26,735	6,735	23,910
Net earnings before interest charges and preferred dividends	139,633	125,327	125,684
Net interest charges	51,375	66,189	61,412
Preferred Stock Dividend Requirements of Subsidiaries	572	586	586
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	87,686	58,552	63,686
Cumulative Effect of Changes in Accounting Principles Net of Tax of $23,999	-	36,621	-
Net Earnings	$87,686	$95,173	$63,686
Net Earnings per Common Share			
Basic	$1.45	$1.60	$1.09
Diluted	$1.43	$1.58	$1.07
Dividends Paid per Share of Common Stock	$0.63	$0.61	$0.57

The condensed financial statements in this summary annual report were derived from the consolidated financial statements that appear in PNM Resources, Inc's Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 1, 2005. Copies of the Form 10-K may be obtained by calling PNM Resources Shareholder Services at 1-800-545-4425 or visiting pnmresources.com.

Condensed Consolidated Balance Sheets

PNM Resources, Inc. and Subsidiaries

(In thousands)	YEAR ENDED DECEMBER 31, 2004	2003
ASSETS		
Utility Plant		
Utility plant	$3,310,266	$3,180,658
Less accumulated depreciation and amortization	1,135,510	1,063,645
	2,174,756	2,117,013
Construction work in progress	124,381	133,317
Nuclear fuel, net	25,449	25,917
Net utility plant	2,324,586	2,276,247
Other Property and Investments		
Investment in lessor notes	308,680	330,339
Other investments	141,285	115,728
Total other property and investments	449,965	446,067
Current Assets		
Cash and cash equivalents	17,195	12,694
Accounts receivable, net	249,701	198,199
Inventories	41,352	40,799
Other current assets	55,306	54,271
Total current assets	363,554	305,963
Deferred Charges		
Regulatory assets	217,196	215,416
Other deferred charges	132,334	134,936
Total deferred charges	349,530	350,352
	$3,487,635	$3,378,629
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stockholders' equity	$1,099,579	$1,077,304
Cumulative preferred stock of subsidiary	11,529	12,800
Long-term debt	987,823	987,210
Total capitalization	2,098,931	2,077,314
Current Liabilities		
Short-term debt	94,700	125,918
Accounts payable	117,645	86,155
Other current liabilities	144,272	133,508
Total current liabilities	356,617	345,581
Deferred Credits		
Accumulated deferred income taxes and investment tax credits	319,888	288,560
Regulatory liabilities	327,419	316,384
Asset retirement obligations	50,361	46,416
Other deferred credits	334,419	304,374
Total deferred charges	1,032,087	955,734
	$3,487,635	$3,378,629

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Condensed Consolidated Statements of Cash Flows

PNM Resources, Inc. and Subsidiaries

(In thousands)	YEAR ENDED DECEMBER 31, 2004	2003	2002
Cash Flows From Operating Activities			
Net earnings	$87,686	$95,173	$63,686
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	131,625	144,854	115,415
Accumulated deferred income tax	39,966	90,175	44,138
Transition costs write-off	-	16,720	-
Loss on reacquired debt	-	16,576	-
Cumulative effect of a change in accounting principle	-	(60,620)	-
Net unrealized (gains) losses on trading and investment contracts	(1,640)	(1,360)	(29,513)
Net change in certain assets and liabilities	(21,882)	(72,826)	(96,367)
Net cash flows from operating activities	235,755	228,692	97,359
Cash Flows From Investing Activities			
Utility plant additions	(145,710)	(177,204)	(240,225)
Redemption of available-for-sale investments	-	80,291	76,633
Combustion turbine payments	-	(11,136)	(29,975)
Return of principle PVNGS lessor notes	20,292	18,360	17,531
Other	(19,033)	(11,878)	(24,391)
Net cash flows from operating activities	(144,451)	(101,567)	(200,427)
Cash Flows From Financing Activities			
Short-term borrowings (repayments), net	(31,218)	(24,082)	115,000
Long-term debt borrowings	-	483,882	-
Long-term debt repayments	-	(476,572)	-
Premium on long-term debt refinancing	-	(23,905)	-
Refund costs of pollution control bonds	-	(31,427)	-
Exercise of employee stock options	(16,430)	(9,639)	(2,412)
Dividends paid	(38,848)	(36,702)	(34,226)
Other	(307)	312	-
Net cash flows from operating activities	(86,803)	(118,133)	78,362
Increase (Decrease) in Cash and Cash Equivalents	4,501	8,992	(24,706)
Beginning of Year	12,694	3,702	28,408
End of Year	$17,195	$12,694	$3,702
Supplemental Cash Flow Disclosures			
Interest paid, net of capitalized interest	$46,469	$69,046	$53,041
Income taxes paid (refunded), net	$14,459	$(23,154)	$13,541
Non Cash Transactions			
Long-term debt assumed for transmission line	-	-	$26,152
Pension contribution of PNM Resources, Inc. common stock	-	$28,950	-

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Shareholder Information

PNM Resources, Inc. and Subsidiaries

2005 ANNUAL MEETING

The 2005 Annual Meeting of Stockholders will be held at 9:00 am on May 17, 2005 at the National Hispanic Cultural Center, Bank of America Theatre, 1701 Fourth Street SW, Albuquerque, NM. Proxies will be requested from stockholders when the notice of meeting and proxy statement are mailed on or about April 1.

TRANSFER AGENT AND REGISTRAR

Corporate Headquarters:
Mellon Investor Services
PO Box 3338
South Hackensack, NJ 07606-1938
Phone: 1-877-663-7775

Website: melloninvestor.com
Overnight, Registered or Certified Mail:
Mellon Investor Services
85 Challenger Road
Ridgefield Park, NJ 07660

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

PNM Resources offers a dividend reinvestment and direct stock purchase plan as a service to both new investors and current shareholders. In addition to full or partial reinvestment of dividends, the PNM Direct Plan gives shareholders the opportunity to make direct cash investments. More information about the plan and enrollment forms are available by calling Mellon Investor Services at 1-877-663-7775 or by visiting Mellon's website at melloninvestor.com.

Mellon has done an excellent job as our agent in processing requests for transfer of share ownership, address changes and other routine transactions. But if you prefer to deal with someone in PNM Resources Shareholder Services, please feel free to call us anytime during business hours. You can reach a PNM Resources representative by calling us directly at 1-800-545-4425.

SECURITIES INFORMATION

PNM Resources' common stock is listed on the New York Stock Exchange under the symbol PNM. The newspaper listing is PNM Res. As of January 31, 2005, there were 14,557 common shareholders of record.

DIVIDENDS DECLARED AND COMMON STOCK PRICE: (IN DOLLARS)

(Please note that the dividend and stock prices have been adjusted for the 3-for-2 stock split that occurred on June 11, 2004)

	2004			2003		
		STOCK PRICE			STOCK PRICE	
QTR	DIVIDEND	HIGH	LOW	DIVIDEND	HIGH	LOW
1	$ 0.16	$ 21.20	$ 18.77	$ 0.15	$ 15.99	$ 12.63
2	$ 0.16	$ 20.87	$ 18.70	$ 0.15	$ 18.56	$ 14.56
3	$ 0.16	$ 22.75	$ 20.09	$ 0.15	$ 19.31	$ 16.87
4	$ 0.185	$ 26.11	$ 22.57	$ 0.15	$ 19.64	$ 17.52

For further information regarding dividends, please see discussion in the Company's Annual Report on Form 10-K.

REPORTS AND PUBLICATIONS

Copies of the Company's Annual Report on Form 10-K and Quarterly Report Form 10-Q to the Securities and Exchange Commission (SEC), proxy statement, all news releases, a 5-year Financial and Statistical Report, up-to-date stock quotes, quarterly earnings results and other corporate literature are available free upon request by calling 505-241-2868, by accessing the information on the Internet at pnmresources.com or by writing the Executive Director, Investor Relations & Corporate Planning.

CONTACT INFORMATION

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Albuquerque, NM 87158
Phone: 505-241-2700
Website: pnmresources.com

Investor Services:
Lisa K. Rister
Executive Director, Investor Relations & Corporate Planning
Phone: 505-241-2787
Fax: 505-241-2367
E-Mail: lrister@pnm.com

Design: Kline & Kline Brand Consultants Photography: Michael Barley

PNM Resources

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