APS

Scott A. Bauer
Department Leader
Regulatory Affairs
Palo Verde Nuclear
Generating Station

Tel: 623/393-5978
Fax: 623/393-5442
e-mail: sbauer@apsc.com

Mail Station 7636
P.O. Box 52034
Phoenix, AZ 85072-2034

10 CFR 50.71(b)

102-04621-SAB/TNW/CJJ
October 30, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-37
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, & 3
Docket Nos. STN 50-528/529/530
Submittal of 2000 Annual Financial Reports

Pursuant to 10 CFR 50.71(b), enclosed please find copies of the 2000 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 Bauer

SAB/TNW/CJJ/kg

Enclosure

cc: E. W. Merschoff (all w/enclosure)
L. R. Wharton
J. M. Moorman

M004

ENCLOSURE

PALO VERDE NUCLEAR GENERATING STATION

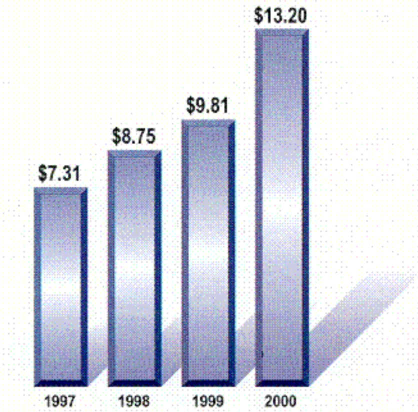
2000 ANNUAL FINANCIAL REPORTS

EL PASO ELECTRIC

2000 ANNUAL REPORT

2000 Performance Highlights

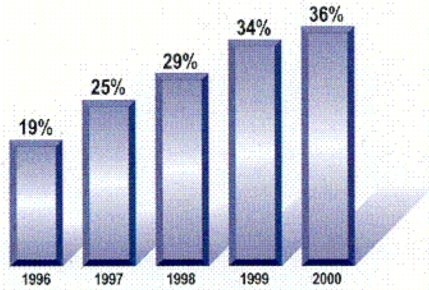
Market Price Per Share
(year-end)



Earnings Per Share
(diluted weighted average)

*1999 excludes unusual non-recurring items.

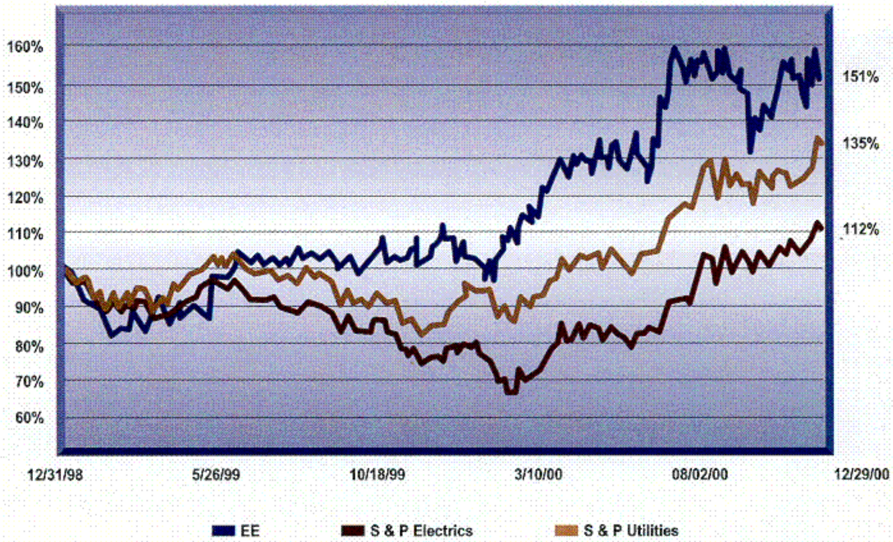
Common Stock Equity
(percent of capitalization)



Financial ($000)	**1998**	**1999**	**2000**
Operating Revenue (net of energy expenses)	$ 471,763	$ 460,672	$ 480,885
EBITDA	$ 263,389	$ 241,464	$ 257,186
Net Income (applicable to common stock)	$ 45,709	$ 46,774*	$ 58,392
Total Assets	$ 1,891,219	$ 1,625,891	$ 1,614,621
EBITDA Interest Coverage	3.22x	2.98x	3.62x
Common Stock Data			
Earnings Per Share (diluted weighted average)	$ 0.75	$ 0.78*	$ 1.06
Free Cash Flow Per Share	$ 2.24	$ 1.88	$ 2.28
Market Price Per Share (year-end close)	$ 8.75	$ 9.81	$ 13.20
Book Value Per Share	$ 6.92	$ 7.36	$ 8.00
Market To Book Ratio	126%	133%	165%
Price Earnings Ratio	11.67x	12.58x*	12.45x
Return on Book Equity	11.62%	10.92%*	13.71%*
Weighted Average Number of Common Shares Outstanding	60,168,234	59,349,468	54,183,915
Number of Registered Holders	5,864	5,547	5,257
Shares of Common Stock Repurchased		3,169,289	5,991,178

* 1999 results before the effects of unusual and non-recurring items.

Relative Price Performance
El Paso Electric vs. S & P Electric and S & P Utilities Indices
12/31/98 - 12/29/00



Statements in this document, other than statements of historical information, are forward-looking statements that are made pursuant to the safe harbor provision 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, 2000, 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 filing 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.

C01

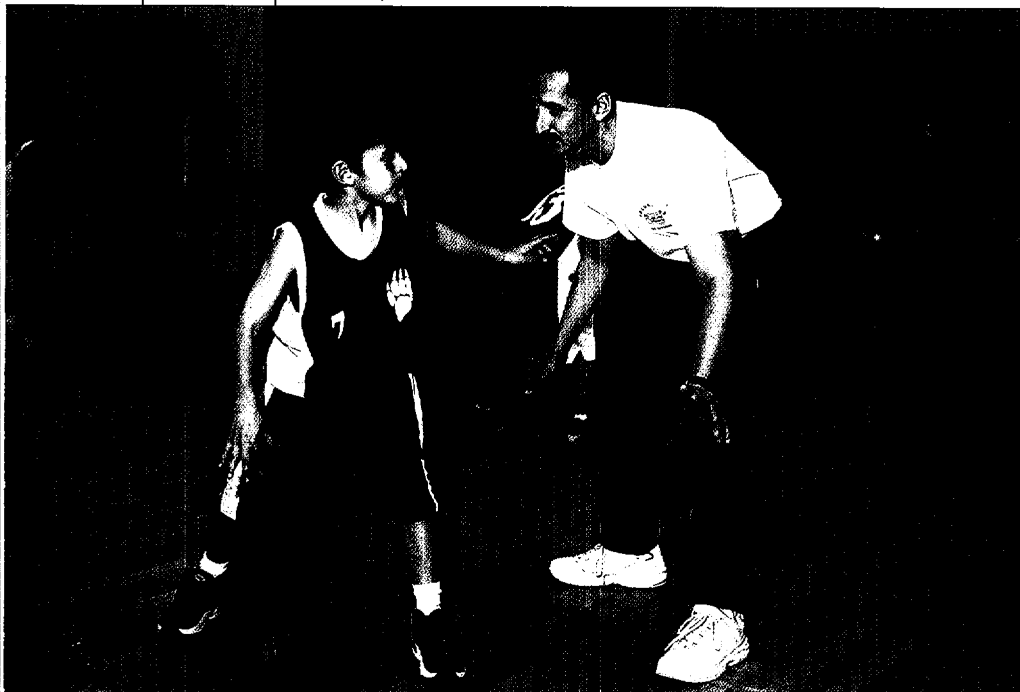
Dear Shareholders:

El Paso Electric in 2000 marked its fifth straight year of increasing earnings and share value. EPE continued to prepare for retail competition, now scheduled to begin for our New Mexico customers in January of 2007 and for our Texas customers in August of 2005. This substantial preparation period shelters our investors and customers from the growing pains evident in some of the earlier moves to competition, assures EPE of ample time to recover stranded costs, and provides us with knowledge about the competitive marketplace prior to the beginning of retail competition.

In early 2000, EPE successfully completed two multi-year goals. Our credit quality was upgraded by Fitch, IBCA / Duff & Phelps in January 2000 and is now rated investment grade by all three major credit rating agencies. In February 2000, after thirteen years of difficult litigation, EPE and the City of Las Cruces reached a settlement ending all court and administrative issues pertaining to the City's municipalization efforts and granting EPE a seven-year franchise agreement with renewal provisions.

Our free cash flow, during 2000, remained strong at $2.28 per share enabling us to reduce debt during the year by over $38 million. This reduction in debt has decreased annual fixed charges on an ongoing basis by $3.4 million. We will redeem the remaining $34.6 million of our Series B bonds at maturity in May 2001. As a result of this aggressive debt reduction plan, EPE's common stock equity increased to 36 percent of long-term capitalization (excluding current maturities) at year-end, a

School children enjoy the EPE display at El Paso's Insights Science Museum.



EPE employee and volunteer yourth basketball coach Jaime Chacon instructs one of his players on improving his basketball skills.

dramatic improvement from the June 30, 1996 level of 19 percent. EPE also remarketed approximately $193 million of Pollution Control Bonds on an unsecured basis in 2000. These bonds previously had been supported by letters of credit secured by First Mortgage Collateral Bonds. The release of these First Mortgage Collateral Bonds further enhances the quality of our remaining bonds.

Of equal importance to our credit quality improvement is our 12 million-share common stock repurchase program started on June 14, 1999. Almost six million shares were repurchased during 2000. As of January 29, 2001, over the life of the program, more than 9.3 million shares had been repurchased for $97.8 million, including commissions. This common stock share reduction added almost $0.09 per share to diluted earnings before extraordinary items in 2000. Future reductions in either fixed obligations or common stock repurchases will depend on the comparative economic value of alternative uses of cash.

At $13.20, our year-end closing stock price increased for the fifth consecutive year and produced a one-year return of almost 35 percent. Our stock price between 1998 and 2000 increased by almost 51 percent, significantly outperforming both the S & P Electric Utilities Index and the S & P Utilities Index which increased 12 and 35 percent, respectively, over the same time period.

Diluted earnings per common share before extraordinary items increased to $1.09. This performance was significantly enhanced by increased demand and prices in the western power market causing EPE's profit margins on economy sales to account for approximately 29 percent of after tax earnings, compared to 16 percent in 1999. While EPE welcomes the increased sales and margins, there is no guarantee that these conditions will continue. The electric utility industry continues to face significant issues relating to escalating natural gas prices and uncertainty about utility restructuring.

Sharply increased natural gas prices have required utilities across the nation to increase the fuel cost component of their rates. EPE has been no exception in that regard. In September of 2000, EPE increased the fuel cost component of its Texas rates. In January of 2001, EPE requested a further increase as well as a surcharge to collect almost $20 million in previously unrecovered fuel costs in Texas. Approval of these requests could be received as early as May 2001. In New Mexico, EPE agreed to freeze its fuel costs as part of the 1998 Rate Stipulation. This freeze expires May 1, 2001, and EPE will seek recovery of increased fuel costs in New Mexico at that time.

EPE owns 1,500 MW of generating capacity which provides a physical hedge against rising wholesale prices and is sufficient to meet the present and near-term projected electricity needs of its service territory. The Palo Verde Nuclear Generating Station, which supplied approximately 50 percent of EPE's energy mix in 2000, operated at a 91 percent capacity factor for the third year in a row, providing a very competitive baseload generation source and a significant buffer against increasing natural gas prices.

Mexico continues to offer substantial growth potential for EPE in addition to the above-average growth expected in its domestic business. In 2000, EPE won contracts from Mexico's national electric utility, the Comisión Federal de Electricidad (CFE), to serve 80 MW in 2000 and 100 MW in 2001 of summer load in Ciudad Juarez. During 2000, electric demand in the CFE's Northern Region, where Juarez is located, grew 7.2 percent. Mexico, as a whole, experienced an increase in electric demand of 8.1 percent.

In early 2001, EPE launched its growing energy services business as a separate subsidiary. MiraSol Energy Services Company, as did its predecessor energy services business unit, will identify, design, and implement energy solutions in lighting, power quality, and distributed generation. A similar energy services market is being developed in Juarez. MiraSol will spearhead this opportunity as well. Project revenue for 2000 was $5.2 million, compared to $2.1 million in 1999.

In early 2000, EPE submitted its transition to competition plan to the New Mexico Public Regulatory Commission (NMPRC). The plan outlines EPE's proposal to create a holding company structure with four subsidiaries: (1) generation, (2) transmission and distribution, (3) energy services, and (4) administrative services. EPE has received most of the approvals necessary to implement its proposed transition plan. In early March 2001, the New Mexico legislature delayed the start of competition in that state by five years until January 1, 2007. Part of the legislation also instructed the NMPRC to approve corporate separation plans which had been previously filed. EPE will address shareholder and Securities and Exchange Commission approval of its proposed reorganization after receipt of formal NMPRC approval. In Texas, EPE is exempt from the competitive provisions of the Texas restructuring legislation until the expiration of its Texas rate freeze in August 2005. Competition in the rest of Texas is scheduled to begin in 2002.

EPE continues to make operational improvements necessary for success in a competitive environment. During the second quarter of 2001, EPE will implement a state-of-the-art customer information system designed to provide products and value-added services to EPE's customers – in addition to the traditional functions of billing and accounting. EPE is also in the process of implementing a state-of-the-art Energy Management System (EMS) scheduled to be online early in the second quarter of 2002. The new EMS will enable EPE to dispatch its generating resources in a more efficient manner.

EPE ranked first, in 2000, in the two system reliability indices reported to the Public Utility Commission of Texas by all investor owned utilities in Texas. In 1999, EPE ranked first in one and second in the other. As evidenced by EPE's sustained superior performance in these indices, EPE's commitment to excellent service continues to be one of its greatest attributes.

Our commitment to excellence extends to corporate citizenship as well. Our community work was significantly recognized on a local and national basis during 2000. EPE received the Greater El Paso Chamber of Commerce Star Award in recognition of outstanding service and commitment to El Paso. For its support of blood drives, EPE was awarded the America's Blood Centers (ABC) National Corporation of the Year Award and the ABC Blood Drives Platinum Award. In its nomination of EPE, United Blood Services of El Paso summarized EPE's philosophy by stating that: "nothing but the highest standards of excellence are acceptable at El Paso Electric."

August 30, 2001 marks EPE's 100th year of service from its modest beginning as El Paso Electric Railway Company in 1901. As we enter a second century of service, we are focused on achieving superior results for shareholders, customers, and employees.

Thank you for your confidence in El Paso Electric.

James Haines

James Haines
President and Chief Executive Officer

George W. Edwards, Jr.
Chairman of the Board

EPE employee and Brownie Leader Barbara Franco presents a badge to Jackie Medina.

Operating Statistics

	2000	1999	1998	1997	1996 (a)	1995	1994	1993	1992	1991
Operating Revenues (in thousands):										
Retail:										
Residential	$ 184,769	$ 164,524	$ 173,215	$ 172,917	$ 163,742	$ 140,799	$ 149,321	$ 144,365	$ 143,150	$ 130,275
Commercial and Industrial, Small	192,895	175,924	174,729	173,318	163,875	142,981	148,024	143,102	141,039	127,521
Commercial and Industrial, Large	65,687	59,497	62,450	64,468	59,041	48,643	51,452	47,930	49,742	47,938
Sales to Public Authorities	86,957	80,393	82,360	82,278	81,185	69,149	73,732	72,529	71,496	65,632
Total Retail	530,308	480,338	492,754	492,981	467,843	401,572	422,529	407,926	405,427	371,366
Wholesale:										
Sales for Resale	70,162	49,441	82,396	83,448	93,737	90,246	102,304	126,187	108,985	73,899
Economy Sales	84,918	32,523	20,167	10,612	11,032	6,681	5,672	3,078	4,982	12,573
Total Wholesale	155,080	81,964	102,563	94,060	104,769	96,927	107,976	129,265	113,967	86,472
Other	16,261	8,167	6,506	4,980	3,981	3,744	4,050	4,433	3,575	3,023
Total Operating Revenues	$ 701,649	$ 570,469	$ 601,823	$ 592,021	$ 576,593	$ 502,243	$ 534,555	$ 541,624	$ 522,969	$ 460,861
Number of Customers (end of year):										
Residential	271,588	266,627	260,356	254,348	250,209	245,245	240,368	235,151	228,688	223,684
Commercial and Industrial, Small	27,947	27,274	26,396	25,900	25,304	24,615	23,857	23,338	22,883	22,417
Commercial and Industrial, Large	133	124	117	115	102	89	80	74	68	68
Other	4,054	3,957	3,867	3,811	3,711	3,674	3,470	3,395	3,251	3,156
Total Customers	303,722	297,982	290,736	284,174	279,326	273,623	267,775	261,958	254,890	249,325
Energy Supplied, Net, MWh:										
Generated	8,706,790	8,392,890	8,586,098	8,186,187	7,920,675	7,439,404	7,018,423	6,625,162	7,330,004	6,128,171
Purchased and Interchanged	905,770	328,225	478,396	617,651	711,791	584,853	1,051,251	1,416,172	589,288	1,273,440
Total Energy Supplied	9,612,560	8,721,115	9,064,494	8,803,838	8,632,466	8,024,257	8,069,674	8,041,334	7,919,292	7,401,611
Energy Sales, MWh:										
Retail:										
Residential	1,767,928	1,653,859	1,621,436	1,587,733	1,545,274	1,473,349	1,500,426	1,424,935	1,395,387	1,342,830
Commercial and Industrial, Small	2,026,768	1,943,120	1,891,703	1,834,953	1,779,986	1,754,176	1,721,736	1,616,434	1,555,047	1,511,550
Commercial and Industrial, Large	1,142,163	1,133,751	1,314,428	1,271,449	1,216,941	1,121,329	1,092,028	872,477	911,750	864,025
Sales to Public Authorities	1,177,883	1,135,438	1,120,654	1,090,312	1,110,706	1,068,048	1,081,850	1,034,231	997,483	956,691
Total Retail	6,114,742	5,866,168	5,948,221	5,784,447	5,652,907	5,416,902	5,396,040	4,948,077	4,859,667	4,675,096
Wholesale:										
Sales for Resale	1,282,540	905,975	1,757,880	1,897,885	1,753,553	1,646,357	1,925,671	2,484,128	2,361,204	1,717,850
Economy Sales	1,714,288	1,497,880	888,708	640,017	757,999	538,102	320,026	164,559	264,654	637,425
Total Sales	9,111,570	8,270,023	8,594,809	8,322,349	8,164,459	7,601,361	7,641,737	7,596,764	7,485,525	7,030,371
Losses and Company Use	500,990	451,092	469,685	481,489	468,007	422,896	427,937	444,570	433,767	371,240
Total, Net	9,612,560	8,721,115	9,064,494	8,803,838	8,632,466	8,024,257	8,069,674	8,041,334 (b)	7,919,292 (b)	7,401,611 (b)
Native System:										
Peak Load, MW	1,159	1,159	1,167	1,122	1,105	1,088	1,093	997	974	929
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500	1,500	1,500	1,497	1,497	1,497	1,497
Load Factor	65.4%	62.5%	63.1%	64.0%	63.4%	61.6%	61.1%	62.1%	62.3%	62.6%
Total System:										
Peak Load, MW	1,360	1,287	1,439	1,442	1,387	1,374	1,365	1,335	1,302	1,142
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500	1,500	1,500	1,497	1,497	1,497	1,497
Load Factor	64.3%	62.9%	64.3%	64.0%	64.2%	62.0%	63.7%	66.4%	66.4%	67.9%

(a) Financial data is based on the results for the Predecessor Company for periods prior to February 11, 1996 and the Reorganized Company thereafter.
(b) Excludes unbilled MWh.

C 02

2000 Operational Highlights

Operational	1998	1999	2000
Retail GWH Sold	5,948	5,866	6,115
Native Peak (MW)	1,167	1,159	1,159
Customers at Year-End	290,736	297,982	303,722
% Change	2.3%	2.5%	1.9%
Employees at Year-End (including temporaries)	1,066	1,068	1,037
Palo Verde Capacity Factor	91%	91%	91%

Generating Capacity

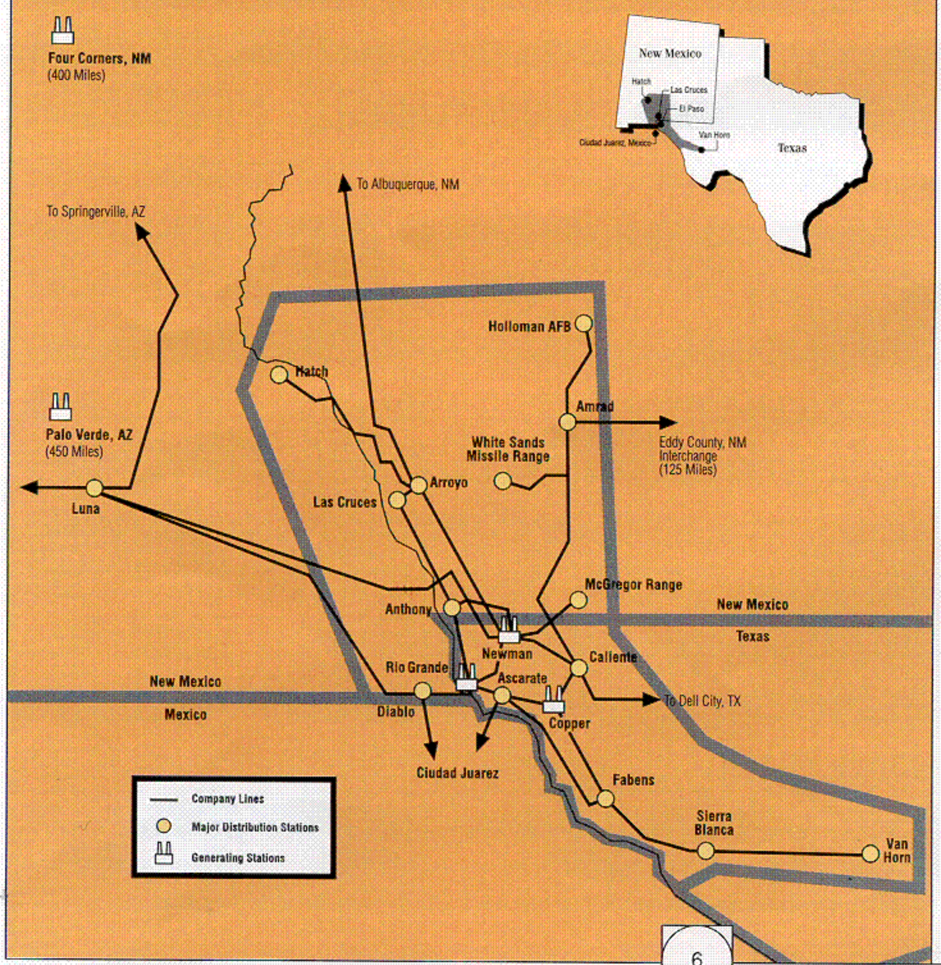
Plant	Entitlement	Fuel Source
Palo Verde	600 MW	Nuclear
Newman	482 MW	Natural Gas
Rio Grande	246 MW	Natural Gas
Four Corners	104 MW	Coal
Copper	68 MW	Natural Gas
TOTAL	**1,500 MW**	

Energy Sources

Nuclear Fuel	50%
Natural Gas	33%
Purchased Power	9%
Coal	8%

A 1.3 MW wind project is scheduled for operation April 2001.

Service Area



Estimated Capital Expenditures

Year	(in millions)
2000	$ 63*
2001	$ 66
2002	$ 66
2003	$ 65
2004	$ 62
Total	$322

*Actual

Wholesale Contracts

Imperial Irrigation District of California
100 MW Firm Capacity
50 MW Contingent
Expires April 2002

Comisión Federal de Electricidad
40 MW Firm (May 2001)
100 MW Firm (June-Sept. 2001)
Expires September 2001

Texas-New Mexico Power Co.
Up to 75 MW Firm
Expires December 2002

Military Contracts

Ft. Bliss Army Air Defense Center
Expires December 2008

Holloman Air Force Base
Expires December 2005

White Sands Missile Range
Expires May 2009

Palo Verde Performance

Institute of Nuclear Power Operations (INPO)

Date	Rating
September 1999	1
October 1997	1
October 1995	1

INPO evaluates seven areas: (1) Organization and Administration, (2) Operations, (3) Maintenance, (4) Engineering, (5) Chemistry, (6) Radiological Protection, and (7) Training.

The evaluation range is 1 to 5, with 1 being the highest score. INPO plant evaluations are conducted on a 12-18-month cycle. The next INPO plant evaluation is scheduled for Summer 2001.

C03

Officers

James Haines
President and Chief Executive Officer

Terry Bassham
Executive Vice President and
General Counsel

Gary R. Hedrick
Executive Vice President
Chief Financial and Administrative Officer

Eduardo A. Rodriguez
Executive Vice President
Chief Operating Officer

J. Frank Bates
Vice President
Transmission and Distribution

Michael L. Blough
Vice President
Administration

John C. Horne
Vice President
Power Generation

Helen Knopp
Vice President
Customer and Public Affairs

Earnest A. Lehman
President
MiraSol Energy Services, Inc.

Robert C. McNiel
Vice President
New Mexico Affairs

Kathryn R. Hood
Treasurer

Kerry B. Lore
Controller

Guillermo Silva, Jr.
Corporate Secretary

Seated left to right: James Haines, George Edwards
Standing left to right: Michael Parks, James Cicconi, James Cardwell, James Harris, Kenneth Heitz, Wilson Cadman, Eric Siegel, Ramiro Guzman, Stephen Wertheimer, Patricia Holland-Branch and Charles Yamarone

Board of Directors

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

Wilson K. Cadman
Retired in 1992. Prior to retirement, Chairman of the Board, President and CEO, Kansas Gas and Electric Company, Wichita, KS and Vice Chairman of the Board of Western Resources, Inc.
Topeka, KS

James A. Cardwell
Chairman of the Board and CEO
Petro Shopping Centers, LP
El Paso, TX

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

Ramiro Guzman
Owner
Ramiro Guzman & Associates
El Paso, TX

James Haines
President and CEO
El Paso Electric
El Paso, TX

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

Kenneth A. Heitz
Partner
Irell & Manella
Los Angeles, CA

Patricia Z. Holland-Branch
President, CEO and Owner
HB/PZH Commercial Environments, Inc.
El Paso, TX

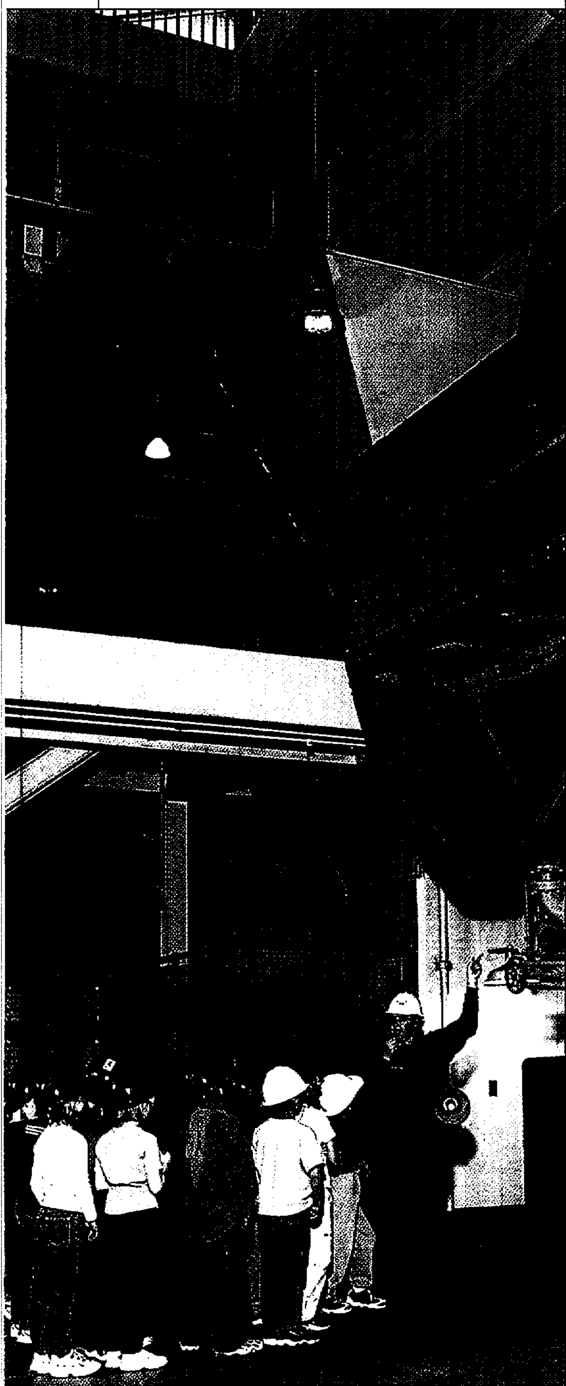
Michael K. Parks
Retired in 2000. Prior to retirement, President and Chief Investment Officer, Aurora National Life Assurance Co.
Los Angeles, CA

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

Stephen N. Wertheimer
Managing Director
Credit Research & Trading
Greenwich, CT

Charles A. Yamarone
Executive Vice President
U.S. Bancorp Libra
Los Angeles, CA

Shareholder Information



EPE employee Dorothy Baca conducts a power plant tour for school children at EPE's Rio Grande Power Plant.

Securities and Records

The common stock of El Paso Electric is traded on the American Stock Exchange. The ticker symbol is EE.

EPE and The Bank of New York (BONY) act as co-transfer agents and 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 on Form 10-K for the year ended December 31, 2000, 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 telephoning BONY Shareholder Services at (800) 524-4458. This service is available to all shareholders Monday through Friday, 8 a.m. to 6 p.m., ET.

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

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

Annual Meeting of Shareholders

The annual meeting of El Paso Electric's shareholders will be held at 10 a.m., Mountain Daylight Time on Thursday, May 10, 2001 in the Paul Kayser Center, 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 2000, were mailed on or about April 4, 2001 to shareholders of record as of March 12, 2001.

Form 10-K

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(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, 2000

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ____ to ____

Commission file number 0-296

El Paso Electric Company

(Exact name of registrant as specified in its charter)

Texas	**74-0607870**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Kayser Center, 100 North Stanton, El Paso, Texas	**79901**
(Address of principal executive offices)	(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	**American 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 whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. 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]

As of March 9, 2001, the aggregate market value of the voting stock held by non-affiliates of the registrant was $633,570,481.

As of March 9, 2001, there were 51,211,408 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 2001 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	Comision 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
ESBG	The Company's Energy Services Business Group
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 Utility Commission or its successor, New Mexico Public Regulation Commission
New Mexico Restructuring Law	New Mexico Electric Utility Industry Restructuring Act of 1999
New Mexico Settlement Agreement	Stipulation and Settlement Agreement in Case No. 2722, between the Company, the New Mexico Attorney General, the New Mexico Commission staff and most other parties to the Company's rate proceedings, excluding Las Cruces, before the New Mexico Commission providing for a 30-month moratorium on rate increases or decreases and other matters
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
PSCO	Public Service Company of Colorado
SFAS	Statement of Financial Accounting Standards
SPS	Southwestern Public Service Company
TEP	Tucson Electric Power Company
Texas Commission	Public Utility Commission of Texas
Texas Rate Stipulation	Stipulation and Settlement Agreement in Texas Docket 12700, 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 Electric Utility Industry
Texas Settlement Agreement	Settlement Agreement in Texas Docket 20450, 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

TABLE OF CONTENTS

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 wholesale customers in Texas, New Mexico, California and Mexico. The Company owns or has significant ownership interests in five electrical generating facilities providing it with a total capacity of approximately 1,500 MW. For the year ended December 31, 2000, the Company's energy sources consisted of approximately 50% nuclear fuel, 33% natural gas, 8% coal and 9% purchased power.

The Company serves approximately 304,000 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 53% and 7%, respectively, of the Company's revenues for the year ended December 31, 2000). In addition, the Company's wholesale sales include sales for resale to the Imperial Irrigation District, Texas-New Mexico Power Company and the Comision Federal de Electricidad de Mexico, as well as sales to power marketers, primarily Enron Power Marketing, Inc. ("Enron"). Principal industrial and other large customers of the Company include steel production, copper and oil refining, garment manufacturing 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 Energy Services Business Group began developing energy efficiency products and services in 1997. The Company incorporated the ESBG as MiraSol Energy Services, Inc., a wholly-owned subsidiary of the Company, which began operations in March 2001. The Company named Earnest Lehman, former Vice President of the ESBG, as President of MiraSol. MiraSol offers customers value-added products and services that give them greater value for the kWh purchased from the Company. MiraSol offers a variety of services to reduce energy use and/or lower energy costs for large electricity users, including energy efficient retrofits of lighting and climate control equipment, on-site (customer-based) generation for standby services or peak shaving, power quality improvement, and energy management systems. MiraSol is also offering these services on a limited pilot basis to maquiladora customers in Ciudad Juarez, Mexico. MiraSol provides these services through a local, regional and national network of strategic allies.

The Company's principal offices are located at the Kayser Center, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of February 27, 2001, the Company had approximately 1,000 employees, 32% of whom are covered by a collective bargaining agreement.

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, and 68 MW from its Copper Power Station.

Palo Verde Station

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde, located west of Phoenix, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company, PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District 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 proportionate share of fuel, other operations, maintenance and capital costs. The Company's average monthly share of these costs was approximately $7.0 million in 2000. 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, over their estimated useful lives of 40 years (to 2024, 2025 and 2027, respectively). The Company's funding requirements are determined periodically based upon engineering cost estimates performed by outside engineers retained by APS.

In December 1998, the Palo Verde Participants approved an updated decommissioning study. The 1998 study determined that the Company will have to fund approximately $280.5 million (stated in 1998 dollars) to cover its share of decommissioning costs. Cost estimates for decommissioning have increased with each study. The previous cost estimate from a 1995 study determined that the Company would have to fund approximately $229 million (stated in 1995 dollars). The 1998 estimate reflects a 22% increase from the 1995 estimate primarily due to increases in estimated costs for spent fuel storage after operations have ceased. See "Spent Fuel Storage" below.

Although the 1998 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 and a new study is expected to be completed during the fourth quarter of 2001. See "Disposal of Low-Level Radioactive Waste" below.

The Company will recover its current decommissioning cost estimates in Texas through its existing rates during the Freeze Period, and thereafter through a non-bypassable wires charge under the provisions of the Texas Restructuring Law. The rate freeze under the Texas Rate Stipulation and the rate reduction under the Texas Settlement Agreement preclude the Company from seeking a rate increase in Texas to recover increases in decommissioning cost estimates during the Freeze Period. See "Regulation – Texas Regulatory Matters – Deregulation" for further discussion.

The Company is currently collecting its decommissioning costs in New Mexico under the New Mexico Settlement Agreement, which expires in April 2001. The Company is preparing a rate case filing with the New Mexico Commission and will request recovery of the Company's future New Mexico decommissioning cost estimates through regulated rates after the expiration of the rate freeze under the New Mexico Settlement Agreement. See "Regulation – New Mexico Regulatory Matters" for further discussion.

Spent Fuel Storage. The spent fuel storage facilities at Palo Verde will have sufficient capacity to store all fuel expected to be discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities are currently being constructed to supplement existing facilities. Spent fuel will be removed from the original facilities as necessary and placed in special storage casks which will be stored at the new facilities until accepted by the DOE for permanent disposal. The alternative facilities will be built in stages to accommodate casks on an as needed basis and are expected to be available for use by the end of 2002.

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. In November 1989, the DOE 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 1998 decommissioning study assumes that only 14 of 333 spent fuel casks will have been removed from Palo Verde by 2037 when title to the remaining spent fuel is assumed to be transferred to the DOE. In January 1997, the Texas Commission established a project to evaluate what, if any, action it should take with regard to payments made to the DOE for funding of the DOE's obligation to start accepting spent nuclear fuel by January 31, 1998. After receiving initial comments, no further action has been taken on the project.

In July 1998, APS filed, on behalf of all Palo Verde Participants, a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking confirmation that findings by the Circuit Court in a prior case brought by Northern States Power regarding the DOE's failure to comply with its obligation to begin accepting spent nuclear fuel would apply to all spent nuclear fuel contract holders. The Circuit Court held APS' petition in abeyance pending the United States Supreme Court's decision to review the Northern States Power case. In November 1998, the Supreme Court denied review of this case. The Circuit Court subsequently dismissed APS' petition after the Circuit Court issued clarifying orders essentially granting the relief sought by APS. APS is monitoring pending litigation between the DOE and other nuclear operators before initiating further legal proceedings or other procedural measures on behalf of the Palo Verde Participants to enforce the DOE's statutory and contractual obligations. The Company is unable to predict the outcome of these matters at this time.

The Company expects to incur significant spent fuel storage costs during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs will be expensed as incurred until an agreement is reached with the DOE for recovery of these costs. However, the Company cannot predict when, if ever, these additional costs will be recovered from the DOE.

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. However, 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.

Steam Generators. Palo Verde has experienced some degradation in the steam generator tubes of each unit. APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS believes its remedial actions have slowed the rate of tube degradation.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during scheduled outages of the Palo Verde units. In December 1999, the Palo Verde Participants unanimously approved installation of new steam generators in Unit 2. APS currently estimates it will install these new steam generators during the fourth quarter of 2003. The Company's portion of total costs associated with construction and installation of new steam generators in Unit 2 is currently estimated not to exceed $45 million, including approximately $4.9 million of replacement power costs. APS has also stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated lives of 40 years. However, APS is reassessing whether it is economically desirable to replace the steam generators in Units 1 and 3. Any such replacements would also require the unanimous approval of the Palo Verde Participants.

The Texas Rate Stipulation precludes the Company from seeking a rate increase during the Freeze Period to recover additional capital costs associated with the replacement of steam generators. The Company may request recovery of a portion of these costs through regulated rates in New Mexico. See "Regulation – New Mexico Regulatory Matters" for further discussion. Finally, the Company cannot assure that it will be able to recover these capital costs through its wholesale power rates or its competitive retail rates that become applicable after the start of competition. See also Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Overview."

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability under federal law. 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 an assessment to cover any loss in excess of $200 million. Effective August 1998, the maximum 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 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. Finally, the Company 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 four generating units with an aggregate capacity of 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 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. The two coal-fired generating units each have 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.

Four Corners is located on land held on easements from the federal government and a lease from the Navajo Nation that expires in 2016. 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 leases the combustion turbine and other generation equipment at the station under a lease that expires in July 2005, with an extension option for two additional years.

Transmission and Distribution Lines and Agreements

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

Springerville-Diablo Line. The Company 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, providing 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 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. As a participant in the Southwest New Mexico Transmission Project Participation Agreement, the Company owns 40% of a 60-mile, 345 kV transmission line from TEP's Greenlee Substation in Arizona to the Hidalgo Substation near Lordsburg, New Mexico, 57.2% of a 50-mile, 345 kV transmission line between the Hidalgo Substation and the Luna Substation near Deming, New Mexico, 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.

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. This terminal enables the Company to connect its transmission system to that of SPS, providing the Company with access to emergency power from SPS and power markets to the east.

Palo Verde Transmission. The Company owns 18.7% of two 45-mile, 500 kV lines from Palo Verde to the Westwing Substation and a 75-mile, 500 kV line from Palo Verde to the Kyrene Substation. These lines provide the Company with a transmission path for delivery of power from Palo Verde.

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 and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Substantial expenditures may be required to comply with these regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforeseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company.

Construction Program

The Company has no current plans to construct any new generating facilities to serve retail customers through at least 2004 except for a $2.1 million pilot wind energy project that is expected to go online in April 2001 and supply up to 1.32 MW. Utility construction expenditures reflected in the following table consist primarily of expanding and updating the electric transmission and distribution systems, and the cost of improvements at and the purchase and installation of new steam generators for Palo Verde. The Company's estimated cash construction costs for 2001 through 2004 are approximately $259 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) (In millions)		By Function (In millions)	
2001	$ 66	Production (1)	$ 81
2002	66	Transmission	16
2003	65	Distribution	110
2004	62	General	52
Total	$ 259	Total	$ 259

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

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:

Power Source	Years Ended December 31, 2000	1999	1998
Nuclear fuel	50%	55%	52%
Natural gas	33	33	35
Coal	8	8	7
Purchased power	9	4	6
Total	100%	100%	100%

Allocated fuel and purchased power costs are generally passed through directly to customers in Texas pursuant to applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the Texas Commission to determine whether a refund or surcharge based on such historical costs and revenues is necessary. Prior to the New Mexico Settlement Agreement, the Company was required to make annual filings reconciling the revenues collected under its New Mexico fixed fuel factor with its New Mexico fuel and purchased power expenses. As a result of the New Mexico Settlement Agreement, the fixed fuel factor has been incorporated into base rates. See "Regulation – Texas Regulatory Matters" and "– New Mexico Regulatory Matters."

Nuclear Fuel

The 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 hexaflouride; the enrichment of uranium hexaflouride; the fabrication of fuel assemblies; the utilization of the fuel assemblies in the reactors; and the storage and disposal of the spent fuel. The Company has contracts for uranium concentrates which should be sufficient to meet the Company's share of Palo Verde's operational requirements through 2002. The Palo Verde Participants have contracts for conversion services to meet approximately 75% of plant requirements in 2001 and 80% of plant requirements in 2002. The Palo Verde Participants have an enrichment services contract that should be sufficient to meet Palo Verde's operational requirements through 2003. APS is currently pursuing several offers to procure uranium, conversion services and enrichment services to satisfy 100% of the needs of Palo Verde through 2008. The Palo Verde Participants have contracts for fuel assembly fabrication services through 2015 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. At December 31, 2000, approximately $48.2 million had been drawn to finance nuclear fuel. This financing 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 First Mortgage Collateral Series Bonds. In the Company's financial statements, the assets and liabilities of the trust are reported as assets and liabilities of the Company.

Natural Gas

In 2000, 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. Interstate gas is delivered under a firm ten-year transportation agreement, which expires in August 2001 with automatic extension provisions through 2005. The Company expects to continue transporting natural gas under this agreement through 2005. The Company manages its natural gas requirements through a combination of long-term contracts and market purchases. The Company anticipates it will continue to purchase natural gas at market prices on a monthly basis for a portion of the fuel needs for the Rio Grande Power Station for the near term. To complement these monthly purchases in 2001, the Company has entered into a one-year fixed-price gas supply contract and a six-month fixed-price contract for the period April through October. 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.

In 2000, natural gas for the Newman and Copper Power Stations was supplied primarily pursuant to a five-year intrastate natural gas contract which became effective January 1, 1997 and expires December 31, 2001. Natural gas was also provided to the Newman and Copper Power Stations pursuant to a similar long-term interstate natural gas contract which supplements the intrastate contract and also expires on December 31, 2001. The Company has begun to evaluate extensions or replacement of these contracts with new contracts for the year 2002 and beyond. 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. The lease expires in 2004 and can be extended for an additional 15 years. 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.

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. For 2000, the Company purchased energy in a 50 MW block transaction from SPS in the months of January through May, November and December and 100 MW in the months of June through October. As of December 31, 2000, the Company had entered into an agreement to purchase 60 MW of firm on-peak energy from Enron for June through September 2001. In addition, on January 1, 2001, the Company entered into a contract with SPS to purchase 103 MW of firm on-peak energy monthly in 2001.

Operating Statistics

	Years Ended December 31,		
	2000	1999	1998
Operating revenues (in thousands):			
Retail:			
Residential	$ 184,769	$ 164,524	$ 173,215
Commercial and industrial, small	192,895	175,924	174,729
Commercial and industrial, large	65,687	59,497	62,450
Sales to public authorities	86,957	80,393	82,360
Total retail	530,308	480,338	492,754
Wholesale:			
Sales for resale	70,162	49,441	82,396
Economy sales	84,918	32,523	20,167
Total wholesale	155,080	81,964	102,563
Other	16,261	8,167	6,506
Total operating revenues	$ 701,649	$ 570,469	$ 601,823
Number of customers (end of year):			
Residential	271,588	266,627	260,356
Commercial and industrial, small	27,947	27,274	26,396
Commercial and industrial, large	133	124	117
Other	4,054	3,957	3,867
Total	303,722	297,982	290,736
Average annual kWh use per residential customer	6,553	6,268	6,291
Energy supplied, net, kWh (in thousands):			
Generated	8,706,790	8,392,890	8,586,098
Purchased and interchanged	905,770	328,225	478,396
Total	9,612,560	8,721,115	9,064,494
Energy sales, kWh (in thousands):			
Retail:			
Residential	1,767,928	1,653,859	1,621,436
Commercial and industrial, small	2,026,768	1,943,120	1,891,703
Commercial and industrial, large	1,142,163	1,133,751	1,314,428
Sales to public authorities	1,177,883	1,135,438	1,120,654
Total retail	6,114,742	5,866,168	5,948,221
Wholesale:			
Sales for resale	1,282,540	905,975	1,757,880
Economy sales	1,714,288	1,497,880	888,708
Total wholesale	2,996,828	2,403,855	2,646,588
Total energy sales	9,111,570	8,270,023	8,594,809
Losses and Company use	500,990	451,092	469,685
Total	9,612,560	8,721,115	9,064,494
Native system:			
Peak load, kW	1,159,000	1,159,000	1,167,000
Net generating capacity for peak, kW	1,500,000	1,500,000	1,500,000
Load factor	65.4 %	62.5 %	63.1 %
Total system:			
Peak load, kW	1,360,000	1,287,000	1,439,000
Net generating capacity for peak, kW	1,500,000	1,500,000	1,500,000
Load factor	64.3 %	62.9 %	64.3 %

Regulation

General

In 1999, both Texas and New Mexico enacted electric utility industry restructuring laws requiring competition in certain functions of the industry and ultimately in the Company's service area. Competition in New Mexico was scheduled to begin on January 1, 2002 under the New Mexico Restructuring Law. On March 8, 2001, the New Mexico Restructuring Law was amended to delay the start of competition for five years until January 1, 2007. The amended New Mexico Restructuring Law permits utilities to form holding companies and participate in unregulated power production, provided the utility does not separate its transmission and distribution activities from its existing generation activities. Under the Texas Restructuring Law, the Company's Texas service area is exempt from competition until the expiration of the Freeze Period in August 2005.

The Company continues to work to become more competitive in response to these restructuring laws as well as other regulatory, economic and technological changes occurring throughout the industry. Deregulation of the production of electricity and related services and increasing customer demand for lower priced electricity and other energy services have accelerated the industry's movement toward more competitive pricing and cost structures. These competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets. Once deregulation is initiated in other portions of Texas in January 2002, the Company may face increasing pressure on its retail rates and its rate freeze under the Texas Rate Stipulation. The Company's results of operations and cash flows may be adversely affected if it cannot maintain its current retail rates.

During 2000, the cost of natural gas and purchased power substantially increased and these increased energy costs may continue in 2001. Under the Company's New Mexico Settlement Agreement, which was in effect during 2000 and will remain in effect through April 2001, the Company bears the risk and benefit of any increases or decreases in energy costs related to its New Mexico retail customers. Upon the expiration of the New Mexico Settlement Agreement, the Company will seek to increase its New Mexico rates to include the higher energy costs that the Company expects to incur. The Company cannot predict whether or to what extent the New Mexico Commission will allow the Company to increase rates to recover the increased energy costs. See "New Mexico Regulatory Matters – Fuel" below and Item 7A "Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."

Texas Regulatory Matters

The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas 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 in Texas and jurisdiction over certain other activities of the Company. The decisions of the Texas Commission are subject to judicial review.

Deregulation. The Texas Restructuring Law requires an electric utility to separate its power generation activities from its transmission and distribution activities by January 1, 2002. The Texas Restructuring Law specifically recognizes and preserves the substantial benefits the Company bargained for in its Texas Rate Stipulation and Texas Settlement Agreement, exempting the Company's Texas service area from retail competition, and preserving rates at their current levels until the end of the Freeze Period. At the end of the Freeze Period, the Company will be subject to retail competition and will have no further claim for recovery of stranded costs. The Company believes that its continued ability to provide bundled electric service at current rates in its Texas service area will allow the Company to collect its Texas jurisdictional stranded costs.

Although the Company is not subject to the Texas restructuring requirements until the expiration of the Freeze Period, the Company sought Texas Commission approval of the Company's corporate restructuring in anticipation of complying with the restructuring requirements of the New Mexico Restructuring Law. In December 2000, the Texas Commission approved the Company's corporate restructuring plan. However, the amended New Mexico Restructuring Law now prohibits the separation of the Company's generation activities from its transmission and distribution activities until January 1, 2007, directly conflicting with the Texas Restructuring Law requiring separation of these activities in 2005. Accordingly, in either 2004 or 2005, the Company will seek New Mexico Commission approval to separate the Company's generation activities from its transmission and distribution activities to allow the Company to comply with the Texas Restructuring Law requirements.

Texas Rate Stipulation and Texas Settlement Agreement. The Texas Rate Stipulation and Texas Settlement Agreement govern the Company's rates for its Texas customers, but do not deprive the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Texas Rate Stipulation (other than the Texas Office of Public Utility Counsel and the State of Texas) agreed to not seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking base rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Texas Rate Stipulation retain all rights provided in the Texas Rate Stipulation, the right to participate as a party in any proceeding related to the merger, and the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings.

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 increases or decreases in energy costs associated with the provision of electricity as well as seek recovery of past undercollections of fuel revenues. Beginning in the second quarter of 2000, the Company's average energy costs exceeded its fuel factor due to substantial increases in the price of natural gas and purchased power. Accordingly, the Company had a significant underrecovery of its actual energy expenses. On August 1, 2000, the Company filed a petition with the Texas Commission to increase its fixed fuel factor. The Company was granted interim approval to implement the increased fuel factor with the first billing cycle in September 2000. The Texas Commission granted final approval of the increased fuel factor on November 1, 2000. The new fuel factor increased fuel revenue collections by $12.2 million in 2000 and is expected to increase fuel revenue collections annually by approximately $37 million.

On January 8, 2001, the Company filed a second petition with the Texas Commission for an additional fuel factor increase and for a 12-month fuel surcharge beginning April 2001. The Company's requested fuel factor would increase fuel revenue collections by approximately $28 million in 2001 and $37 million annually thereafter. The requested surcharge seeks to recover $22.4 million in underrecovered energy expenses the Company incurred in 2000, including interest, approximately $17.3 million of which would be collected in 2001. The Company proposes to spread this surcharge recovery over 12 months to mitigate the impact on customers' monthly bills. The Texas Commission traditionally renders a decision within 90 days of the Company's filing, but the Company requested interim approval of its proposed fuel factor if a final order is not issued in early April 2001.

Any fuel surcharge granted to the Company, as well as the Company's other energy expenses, will be subject to final review by the Texas Commission in the Company's next fuel reconciliation proceeding, which is expected to be filed by the middle of 2002. The Texas Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the prudence of fuel and purchased power expenses.

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 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. The Company has calculated approximately $19.7 million of performance rewards for the three-year periods ended December 31, 2000, 1999 and 1998. These rewards are included, along with energy costs incurred, as part of the Texas Commission's review during the periodic fuel reconciliation proceedings discussed above. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel reconciliation proceeding. 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 March 2001, the New Mexico Legislature amended the New Mexico Restructuring Law to postpone deregulation in New Mexico until January 1, 2007. The amended New Mexico Restructuring Law permits utilities to form holding companies and through the holding company participate in unregulated power production, provided the utility does not separate its transmission and distribution activities from its existing generation activities. The Company is currently evaluating possible benefits, if any, of forming a holding company without separating its power generation activities from its transmission and distribution activities.

The amended New Mexico Restructuring Law prohibiting the separation of the Company's generation activities from its transmission and distribution activities until January 1, 2007, directly conflicts with the Texas Restructuring Law requiring separation of these activities in 2005. Accordingly, in either 2004 or 2005, the Company will seek New Mexico Commission approval to separate the Company's generation activities from its transmission and distribution activities to allow the Company to comply with the Texas Restructuring Law requirements.

Due to the uncertainty of the timing of deregulation in New Mexico, on October 12, 2000, the Company filed with the New Mexico Commission an application to form a wholly-owned energy services subsidiary. In December 2000, the New Mexico Commission approved the Company's application and authorized the Company to invest up to $20 million in the subsidiary. Following this approval, the Company created MiraSol Energy Services, Inc., which began operation in March 2001.

The New Mexico Restructuring Law allows the Company to recover reasonable, prudent and unmitigated costs that the Company would not have incurred but for its compliance with the New Mexico Restructuring Law. These transition costs do not include stranded costs, costs the Company can collect under federally approved rates or rates approved by the New Mexico Commission, or any costs the Company would have incurred regardless of the New Mexico Restructuring Law. The March 2001 amendment to the New Mexico Restructuring Law did not address the recovery of transition costs spent to date. The Company cannot predict whether and to what extent the New Mexico Commission will allow the Company to recover these transition costs during the five year delay. Such costs, to the extent they are not capitalizable as fixed assets, are expensed as incurred.

Fuel. The New Mexico Settlement Agreement entered into in October 1998 incorporated the then existing fuel factor into frozen base rates. Accordingly, the Company must absorb any increases or decreases in energy expenses related to its New Mexico retail customers until new rates are approved following the expiration of this rate freeze in April 2001. The Company is preparing a rate case filing with the New Mexico Commission requesting an increase in the Company's rates beginning May 2001, reflecting current increases in natural gas and purchased power prices. The Company may also request recovery of increases in capital costs related to its New Mexico retail customers as part of this rate case filing. The Company cannot predict what rate increase, if any, the New Mexico Commission may approve or when the New Mexico Commission will ultimately rule on the Company's rate case.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The Company is subject to regulation by the FERC in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

In anticipation of complying with the New Mexico Restructuring Law, the Company filed its Application for Authorization to Transfer Certain Assets and Approval for Certain Securities Transactions with the FERC seeking the necessary FERC approvals for its corporate restructuring. On October 4, 2000, the FERC issued its Order Authorizing Disposition of Jurisdictional Facilities allowing the transfer of assets necessary to implement the Company's corporate restructuring. On October 13, 2000, the FERC issued its order authorizing the securities transactions related to the Company's corporate restructuring.

Fuel. Under FERC regulations, the Company's fuel factor is adjusted monthly for almost all FERC jurisdictional customers. Accordingly, any increases or decreases in energy expenses immediately flow through to such customers.

RTOs. On December 15, 1999, the FERC approved its final rule ("Order 2000") on Regional Transmission Organizations ("RTOs"). Order 2000 strongly encourages, but does not require, public utilities to form and join RTOs. Order 2000 also proposes RTO startup by December 15, 2001. The Company is an active participant in the development of the Desert Southwest Transmission and Reliability Operator ("Desert Star"). The Company believes Desert Star will qualify as an RTO under Order 2000. The Company intends, subject to the resolution of outstanding issues, to participate in Desert Star. As a participating transmission owner, the Company will transfer operations of its transmission system to Desert Star. The Desert Star proposal was submitted to the FERC on October 15, 2000. On March 1, 2001, the Desert Star proposal was updated to inform the FERC that the start of Desert Star operations will be delayed. Desert Star is currently scheduled to become operational by January 1, 2003. If Desert Star should fail to become operational, the Company would seek to participate in another RTO similar to Desert Star.

Department of Energy. The DOE regulates the Company's exports of power to 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. The DOE is authorized to assess operators of nuclear generating facilities for 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.

In anticipation of complying with the New Mexico Restructuring Law, the Company filed its Application for NRC consent to the indirect transfer of control of the Company's minority non-operating ownership interest in Palo Verde as part of the Company's corporate restructuring. In December 2000, the NRC granted all requested approvals.

Sales for Resale

During 2000, the Company provided IID with 100 MW of firm capacity and associated energy and 50 MW of system contingent capacity and associated energy pursuant to a 17-year agreement which expires April 30, 2002. In 2001, the Company will provide IID with similar amounts of capacity and associated energy. The Company also provided TNP with up to 25 MW of firm capacity and associated energy pursuant to an agreement that expires December 31, 2002. The contract allows TNP to specify a maximum annual amount with one year's notice. For 2001, the Company is contracted to provide TNP up to 25 MW of firm capacity and associated energy. The Company has also contracted to sell 40 MW to CFE during the month of May 2001 and 100 MW during the months of June through September 2001.

Power Contracts

As of December 31, 2000, the Company had entered into agreements to sell to Enron 50 MW of firm on-peak energy at Palo Verde for February and March 2001 and 60 MW of firm on-peak energy at Palo Verde from June 2002 through September 2002.

On January 1, 2001, the Company entered into concurrent sales and purchase agreements with SPS and PSCO for 103 MW of firm off-peak capacity and associated energy monthly through 2001. Under these agreements, the Company will receive energy from SPS through the Eddy County tie and deliver the same amount of energy to PSCO at various other transmission points connected to the Company's generation sources. The sale to PSCO is contingent upon the Company receiving the energy from SPS, and the sales and purchase prices under these agreements are structured such that the Company receives a guaranteed margin. The Company is currently negotiating similar agreements with SPS and PSCO for 2002 through 2005. The Company also entered into an agreement with PSCO whereby PSCO has the option to deliver up to 60 MW of firm on- or off-peak capacity and associated energy to the Company at Palo Verde from January through May 2001 and October through December 2001. If PSCO exercises this option and delivers energy to the Company, the Company agrees to deliver the same amount of energy to PSCO at Four Corners. The option agreement provides the Company with the potential of increasing its sales at the Palo Verde hub.

Executive Officers of the Company

Name	Age	Current Position and Business Experience
James Haines	54	Chief Executive Officer, President and Director since May 1996; Executive Vice President and Chief Operating Officer of Western Resources, Inc. from June 1995 to May 1996.
Terry Bassham	40	Executive Vice President and General Counsel since August 2000; Vice President and General Counsel from January 1999 to August 2000; General Counsel since August 1996; Shareholder with Clark, Thomas & Winters, P.C. from May 1993 to August 1996.
Gary R. Hedrick	46	Executive Vice President, Chief Financial and Administrative Officer since August 2000; Vice President, Chief Financial Officer and Treasurer from August 1996 to August 2000; Treasurer since March 1996; Vice President – Financial Planning and Rate Administration from September 1990 to August 1996.
Eduardo A. Rodriguez	45	Executive Vice President and Chief Operating Officer since August 2000; Senior Vice President – Energy Services from January 1999 to August 2000; Senior Vice President – Customer and Corporate Services from August 1996 to January 1999; Senior Vice President since January 1994; General Counsel from 1988 to August 1996.
J. Frank Bates	50	Vice President – Transmission and Distribution since August 1996; Vice President – Operations from May 1994 to August 1996.
Michael L. Blough	45	Vice President – Administration since August 1996; Vice President since May 1995; Controller and Chief Accounting Officer from November 1994 to August 1996.
John C. Horne	52	Vice President – Power Generation since August 1996; Vice President – Power Supply from May 1994 to August 1996.
Helen Knopp	58	Vice President – Customer and Public Affairs since April 1999; Executive Director of the Rio Grande Girl Scout Council from September 1991 to April 1999.
Earnest A. Lehman	48	President – MiraSol Energy Services, Inc. since November 2000; Vice President – Energy Services Business Group from January 1999 to November 2000; Director of Rates of Western Resources, Inc. from January 1998 to January 1999; Director of Wholesale Rates of Western Resources, Inc. from January 1997 to January 1998; Vice President – Consumer Sales of Westar Consumer Services from March 1996 to January 1997; Executive Director of Marketing of Western Resources, Inc. from December 1994 to March 1996.
Robert C. McNiel	54	Vice President – New Mexico Affairs since December 1997; Vice President – Public Affairs and Marketing from August 1996 to December 1997; Vice President – New Mexico Division from December 1989 to August 1996.
Kathryn R. Hood	47	Treasurer since October 2000; Assistant Treasurer from April 1999 to October 2000; Manager of Financial Services from March 1991 to April 1999.
Kerry B. Lore	41	Controller since October 2000; Assistant Controller from April 1999 to October 2000; Manager of Accounting Services from July 1993 to April 1999.
Guillermo Silva, Jr.	47	Secretary since January 1994.

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. See Part II, Item 8, "Financial Statements and Supplementary Data – Note F of Notes to Financial Statements" for information regarding encumbrances against the principal properties of the Company.

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 none of these claims will have a material adverse effect on the financial position, results of operations and cash flows of the Company.

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

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Company's common stock trades on the American Stock Exchange under the symbol "EE." On September 25, 2000, the Company's stock began trading in decimals in compliance with the Securities and Exchange Commission requirement that equity and option markets convert to decimal pricing systems. The high, low and close sales prices for the Company's common stock, as reported in the consolidated reporting system of the American Stock Exchange, for the periods indicated below, were as follows:

	Sales Price		
	High	**Low**	**Close (End of period)**
1999			
First Quarter	$ 8.94	$ 7.00	$ 7.63
Second Quarter	9.19	7.31	8.94
Third Quarter	9.38	8.50	9.00
Fourth Quarter	9.81	8.56	9.81
2000			
First Quarter	$ 10.44	$ 8.13	$ 10.38
Second Quarter	12.00	10.00	11.19
Third Quarter	15.50	10.88	13.77
Fourth Quarter	14.05	11.25	13.20

As of March 9, 2001, there were 5,216 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 deleveraging and stock repurchase programs with the goals of improving its capital structure and using free cash flow to its highest economic advantage.

The Company's Board of Directors previously approved two stock repurchase programs allowing the Company to purchase up to twelve million of its outstanding shares of common stock. As of March 9, 2001, the Company had repurchased 9,568,229 shares of common stock under these programs for approximately $101.4 million, including commissions. The Company expects to continue to make purchases primarily in the open market at prevailing prices and will also engage in private transactions, if appropriate. Any 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, 2000	1999	1998	1997	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996
Operating revenues	$ 701,649	$ 570,469	$ 601,323	$ 592,021	$ 521,921	$ 54,672
Operating income	169,974	157,336	159,717	159,636	142,438	1,362
Income before extraordinary item	60,164	43,809	57,073	54,568	41,919	118,198
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(1,772)	(3,336)	3,343	(2,775)	–	264,273
Net income applicable to common stock	58,392	28,276	45,709	38,649	31,431	382,471
Basic earnings per common share:						
Income before extraordinary item	1.11	0.53	0.70	0.69	0.52	3.33
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(0.03)	(0.05)	0.06	(0.05)	–	7.43
Net income	1.08	0.48	0.76	0.64	0.52	10.76
Weighted average number of common shares outstanding	54,183,915	59,349,468	60,168,234	60,128,505	60,073,808	35,544,330
Diluted earnings per common share:						
Income before extraordinary item	1.09	0.53	0.70	0.69	0.52	3.33
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(0.03)	(0.06)	0.05	(0.05)	–	7.43
Net income	1.06	0.47	0.75	0.64	0.52	10.76
Weighted average number of common shares and dilutive potential common shares outstanding	55,001,625	59,731,649	60,633,298	60,437,632	60,116,709	35,544,330
Cash additions to utility property, plant and equipment	66,960	53,705	49,787	46,467	33,926	4,724
Total assets	1,616,544	1,625,891	1,891,219	1,812,613	1,846,190	1,910,354
Long-term debt and financing and capital lease obligations	740,223	811,607	897,062	966,810	1,046,173	1,164,328
Preferred stock	–	–	135,744	121,319	108,426	100,000
Common stock equity	412,034	421,258	417,278	369,640	331,257	300,000

On February 12, 1996, the Company emerged from a bankruptcy proceeding which it instituted in January 1992. The Company's financial statements for periods after February 12, 1996 are not comparable to the Company's financial statements for periods before February 12, 1996 due to the application of "fresh-start" reporting at that date. A vertical line is shown in the above selected financial data to separate the respective financial information and indicate that it has not been prepared on a consistent basis of accounting.

The selected financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data."

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

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 the Company from time to time, including statements contained in the Company's filings with the Securities and Exchange Commission and its reports to shareholders, involve known and unknown risks and other factors which may cause the Company's actual results in future periods to differ materially from those expressed in any forward-looking statements. Any such statement is qualified by reference to the risks and factors discussed below under the headings "Overview" and "Liquidity and Capital Resources," as well as in the Company's filings with the Securities and Exchange Commission, which are available from the Securities and Exchange Commission or which may be obtained upon request from the Company. The Company cautions that the risks and factors discussed below and in such filings are not exclusive. The Company does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of the Company except as required by law.

Overview

El Paso Electric Company is an electric utility that serves retail customers in west Texas and southern New Mexico and wholesale customers in Texas, New Mexico, California and Mexico. The Company owns or has substantial ownership interests in five electrical generating facilities providing it with a total capacity of approximately 1,500 MW. The Company's energy sources consist of nuclear fuel, natural gas, coal and purchased power. The Company owns or has significant ownership interests in four 345 kV transmission lines and three 500 kV lines to provide power from Palo Verde and Four Corners, and owns the distribution network within its retail service territory. The Company is subject to extensive regulation by the Texas and New Mexico Commissions and, with respect to wholesale power sales, transmission of electric power and the issuance of securities, by the FERC.

The Company faces a number of risks and challenges that could negatively impact its operations and financial results. The most significant of these risks and challenges arise from the deregulation of the electric utility industry, the possibility of increased costs, especially from Palo Verde, and the Company's high level of debt.

The electric utility industry in general and the Company in particular are facing significant challenges and increased competition as a result of changes in federal provisions relating to third-party transmission services and independent power production, as well as changes in state laws and regulatory provisions relating to wholesale and retail service. In 1999, both Texas and New Mexico passed industry deregulation legislation requiring the Company to separate its transmission and distribution functions, which will remain regulated, from its power generation and energy services businesses, which will operate in a competitive market in the future. While the Company is not subject to deregulation in its Texas and New Mexico jurisdictions until 2005 and 2007, respectively, the potential effects of competition in the power generation and energy services markets remain important to the Company. There can be no assurance that the deregulation of the power generation market will not adversely affect the future operations, cash flows and financial condition of the Company.

The changing regulatory environment and the advent of unregulated power production have created a substantial risk that the Company will lose important customers. The Company's wholesale and large retail customers already have, in varying degrees, additional alternate sources of economical power, including co-generation of electric power. For example, a 504 MW combined-cycle generating plant located in Samalayuca, Chihuahua, Mexico, which became fully operational at the end of 1998, gave CFE the capacity to supply electricity to portions of northern Chihuahua and allowed CFE to eliminate substantially all purchases of power from the Company in 1999 and most of 2000. However, on May 31, 2000, CFE agreed to purchase from the Company firm capacity and associated energy sales of up to 80 MW from June 1, 2000 through August 31, 2000, up to 40 MW during May 2001 and up to 100 MW from June 1, 2001 through September 30, 2001. Additionally, American National Power, Inc., a wholly-owned subsidiary of International Power PLC, has announced it is exploring the possibility of building a generation plant in El Paso, Texas, and Duke Energy has announced it is exploring the possibility of building a generation plant in Deming, New Mexico. If the Company loses a significant portion of its retail customer base or wholesale sales, the Company may not be able to replace such revenues through either the addition of new customers or an increase in rates to remaining customers.

Another risk to the Company is potential increased costs, including 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; (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; and (vi) compliance with the various requirements and regulations governing commercial nuclear generating stations. At the same time, the Company's retail base rates are effectively capped through rate freezes ending in August 2005 for Texas and April 2001 for New Mexico. Additionally, upon initiation of competition, there will be competitive pressure on the Company's power generation rates which could reduce its profitability. The Company also 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.

During the second, third and fourth quarters of 2000, the Company was unable to pass through to certain customers increased energy expenses resulting from higher natural gas prices and increased power purchases needed because of unscheduled generating unit outages. The Company is unable to request increased rates in the Company's New Mexico service area prior to May 1, 2001 or under certain wholesale contracts to compensate for these increases in energy expenses. From April 1, 2000 through December 31, 2000, the Company incurred increased energy expenses which cannot be recovered from New Mexico and certain wholesale customers of $7.6 million, net of tax, compared to the same period last year. During 2001, the Company may not be able to recover its increased energy costs from its New Mexico customers. See Part I, Item 1, "Business – Regulation – New Mexico Regulatory Matters – Fuel" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk."

The Company made minimal sales directly to the California Independent System Operator (the "CISO") during early December 2000 and had an outstanding receivable of $0.2 million from the CISO at December 31, 2000. The Company will evaluate future sales to the California market and will make such sales in a manner which minimizes the credit risk and which takes into account the credit worthiness of the counterparty.

Liquidity and Capital Resources

The Company's principal liquidity requirements in the near-term are expected to consist of interest and principal payments on the Company's indebtedness and capital expenditures related to the Company's generating facilities and transmission and distribution systems. The Company expects that cash flows from operations will be sufficient for such purposes.

Long-term capital requirements of the Company will consist primarily of construction of electric utility plant and payment of interest on and retirement of debt. The Company has no current plans to construct any significant amount of new generating capacity to serve retail load through at least 2004. See Part I, Item 1, "Business – Construction Program." Utility construction expenditures will consist primarily of expanding and updating the transmission and distribution systems and the cost of capital improvements and replacements at Palo Verde and other generating facilities, including the replacement of the Palo Verde Unit 2 steam generators.

At December 31, 2000, the Company had approximately $11.3 million in cash and cash equivalents. The Company also has a $100 million revolving credit facility, which provides up to $70 million for nuclear fuel purchases and up to $50 million (depending on the amount of borrowings outstanding for nuclear fuel purchases) for working capital needs. The revolving credit facility's term ends on February 8, 2002, when it is expected to be renewed or replaced on comparable terms. At December 31, 2000, approximately $48.2 million had been drawn for nuclear fuel purchases. No amounts are currently outstanding on this facility for working capital needs.

The Company has a high debt to capitalization ratio and significant debt service obligations. Due to the Texas Rate Stipulation, the Texas Settlement Agreement, and competitive pressures, the Company does not expect to be able to raise its base rates in Texas in the event of increases in non-fuel costs or loss of revenues. See Part I, Item 1, "Business – Regulation – Texas Regulatory Matters." Accordingly, as described below, debt reduction continues to be a high priority for the Company in order to gain additional financial flexibility to address the evolving competitive market.

The Company has significantly reduced its long-term debt since its emergence from bankruptcy in 1996. From June 1, 1996 through March 9, 2001, the Company repurchased approximately $353.7 million of first mortgage bonds as part of an aggressive deleveraging program and repaid the remaining $36.0 million of Series A First Mortgage Bonds at their maturity in February 1999, which has combined to reduce the Company's annual interest expense by approximately $31.2 million. The Company also redeemed its 11.40% Series A Preferred Stock in March 1999, which resulted in the avoidance of approximately $15.9 million in annual cash dividends that would have been payable until mandatory redemption in 2008. Common stock equity as a percentage of capitalization, excluding current maturities of long-term debt, has increased from 19% at June 30, 1996 to 36% at December 31, 2000. In addition, the Company's bonds are now rated investment grade by all three major credit rating agencies.

The Company's Board of Directors previously approved two stock repurchase programs allowing the Company to purchase up to twelve million of its outstanding shares of common stock. As of March 9, 2001, the Company had repurchased 9,568,229 shares of common stock under these programs for approximately $101.4 million, including commissions. The Company expects to continue to make purchases primarily in the open market at prevailing prices and will also engage in private transactions, if appropriate. Any repurchased shares will be available for issuance under employee benefit and stock option plans, or may be retired.

The Company continues to believe that the orderly reduction of debt with a goal of achieving a capital structure that is more typical in the electric utility industry is a significant component of long-term shareholder value creation. Accordingly, the Company will regularly evaluate market conditions and, when appropriate, use a portion of its available cash to reduce its fixed obligations through open market purchases of first mortgage bonds.

The degree to which the Company is leveraged could have important consequences on the Company's liquidity, including (i) the Company's ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate or other purposes could be limited in the future and (ii) the Company's higher than average leverage may place the Company at a competitive disadvantage by limiting its financial flexibility to respond to the demands of the competitive market and make it more vulnerable to adverse economic or business changes.

Historical Results of Operations

	Years Ended December 31,		
	2000	**1999**	**1998**
Net income applicable to common stock before extraordinary item (in thousands)................	$ 60,164	$ 31,612	$ 42,366
Diluted earnings per common share before extraordinary item......................................	1.09	0.53	0.70

Results of operations for 1999 were affected by unusual or infrequent items including (i) the recognition of certain items arising from the Texas Settlement Agreement; (ii) a change in estimated fuel cost reserves; (iii) an adjustment reducing fuel expense based on a reduction of the Company's estimated coal mine reclamation liability; (iv) a charge to earnings of $10.1 million, net of tax, as a result of the settlement agreement with Las Cruces; (v) a one-time charge to earnings of $2.5 million, net of tax, resulting from the write-off of interest capitalized prior to 1999 on postload nuclear fuel; and (vi) the early redemption of the Company's 11.40% Series A Preferred Stock. Results of operations for 1998 reflect a charge to earnings of $3.8 million, net of tax, as a result of the New Mexico Settlement Agreement.

Operating revenues net of energy expenses increased $20.2 million in 2000 compared to 1999 as follows (in thousands):

Years Ended December 31:	2000	1999	Increase/(Decrease)
Operating revenues net of energy expenses before the effects of the Texas Settlement Agreement, a change in estimated fuel cost reserves and a coal mine reclamation adjustment	$ 480,885	$ 449,207	$ 31,678
Texas Settlement Agreement:			
Palo Verde performance reward	–	3,453	(3,453)
Retroactive base rate decrease	–	(2,343)	2,343
Change in estimated fuel cost reserves	–	3,754	(3,754)
Coal mine reclamation adjustment	–	6,601	(6,601)
Total operating revenues net of energy expenses	$ 480,885	$ 460,672	$ 20,213

Excluding the effects of the unusual or infrequent items shown above, the increase in operating revenues net of energy expenses of $31.7 million was primarily due to increased kWh sales and increased margins on economy sales. These increases were partially offset by increased energy expenses not recovered in the Company's New Mexico service area.

Operating revenues net of energy expenses decreased $11.1 million in 1999 compared to 1998 as follows (in thousands):

Years Ended December 31:	1999	1998	Increase/(Decrease)
Operating revenues net of energy expenses before the effects of the Texas Settlement Agreement, a change in estimated fuel cost reserves and a coal mine reclamation adjustment	$ 449,207	$ 470,868	$ (21,661)
Texas Settlement Agreement:			
Palo Verde performance reward	3,453	–	3,453
Retroactive base rate decrease	(2,343)	–	(2,343)
Change in estimated fuel cost reserves	3,754	895	2,859
Coal mine reclamation adjustment	6,601	–	6,601
Total operating revenues net of energy expenses	$ 460,672	$ 471,763	$ (11,091)

Excluding the effects of the unusual or infrequent items shown above, the decrease in operating revenues net of energy expenses of $21.7 million was primarily due to the rate reductions in Texas and New Mexico and the loss of sales to CFE. These decreases were partially offset by increased economy sales.

Operating revenues from retail customers shown below include the effects of the retroactive base rate decrease, the recognition of the Palo Verde performance reward and the changes in estimated fuel cost reserves for the years ended December 31, 1999 and 1998, as applicable. Comparisons of kWh sales and operating revenues are shown below (in thousands):

Years Ended December 31:	**2000**	**1999**	**Increase/(Decrease) Amount**	**Percent**	
Electric kWh sales:					
Retail	6,114,742	5,866,168	248,574	4.2%	
Sales for resale	1,282,540	905,975	376,565	41.6	(1)
Economy sales	1,714,288	1,497,880	216,408	14.4	(2)
Total	9,111,570	8,270,023	841,547	10.2	
Operating revenues:					
Retail	$ 530,308	$ 480,338 (3)	$ 49,970	10.4%	(4)
Sales for resale	70,162	49,441	20,721	41.9	(5)
Economy sales	84,918	32,523	52,395	161.1	(2)
Other (6)	16,261	8,167	8,094	99.1	(7)
Total	$ 701,649	$ 570,469	$ 131,180	23.0	

Years Ended December 31:	**1999**	**1998**	**Increase/(Decrease) Amount**	**Percent**	
Electric kWh sales:					
Retail	5,866,168	5,948,221	(82,053)	(1.4)%	
Sales for resale	905,975	1,757,880	(851,905)	(48.5)	(8)
Economy sales	1,497,880	888,708	609,172	68.5	
Total	8,270,023	8,594,809	(324,786)	(3.8)	
Operating revenues:					
Retail	$ 480,338 (3)	$ 492,754	$ (12,416)	(2.5)%	
Sales for resale	49,441	82,396	(32,955)	(40.0)	(8)
Economy sales	32,523	20,167	12,356	61.3	(9)
Other (6)	8,167	6,506	1,661	25.5	
Total	$ 570,469	$ 601,823	$ (31,354)	(5.2)	

(1) Primarily due to (i) increased kWh sales to IID and (ii) sales to CFE as a result of a contract that was effective from June through August 2000 with no comparable sales to CFE in 1999.

(2) In order to ensure sufficient availability of purchased power during the summer of 2000, the Company entered into a firm purchased power contract in January 2000 that was effective through the end of the year. The increase in economy kWh sales is primarily due to the sale of power purchased under this contract that was not needed to serve native load and wholesale contracts during the non-summer months. The increase in economy sales revenue was primarily due to (i) increased margins, (ii) increased prices as a result of increased fuel costs and (iii) increased kWh sales.

(3) Includes the effects of Texas Settlement Agreement and change in estimated fuel cost reserves of $4.9 million.

(4) Primarily due to (i) increased energy expenses that are passed through directly to Texas jurisdictional customers and (ii) increased kWh sales.

(5) Primarily due to (i) increased energy expenses that are passed through directly to certain wholesale customers and (ii) sales to CFE as noted above.

(6) Represents revenues with no related kWh sales.

(7) Primarily due to energy swaps and ESBG revenues.

(8) The Company's previous one-year sales agreement for firm capacity and associated energy sales to CFE terminated on December 31, 1998.
(9) Primarily due to increased kWh sales.

Other operations and maintenance expense increased $9.9 million in 2000 compared to 1999 as follows (in thousands):

Years Ended December 31:	**2000**	**1999**	**Increase/(Decrease)**	
Maintenance at Company-owned generating plants	$ 12,888	$ 8,780	$ 4,108	(1)
ESBG activity	6,670	3,006	3,664	(2)
Corporate restructuring legal fees	1,305	–	1,305	
Maintenance of general plant	3,640	2,548	1,092	(3)
Pensions and benefits expense	13,850	15,596	(1,746)	(4)
Other	142,403	140,973	1,430	
Total other operations and maintenance expense	$ 180,756	$ 170,903	$ 9,853	

Other operations and maintenance expense decreased $0.7 million in 1999 compared to 1998 as follows (in thousands):

Years Ended December 31:	**1999**	**1998**	**Increase/(Decrease)**	
Regulatory expense	$ 1,578	$ 6,043	$ (4,465)	(5)
Pensions and benefits expense	15,596	19,940	(4,344)	(6)
Customer accounts expense	5,014	3,132	1,882	
Outside services expense	9,790	8,008	1,782	
Non-nuclear generation expense	5,199	3,672	1,527	
Maintenance expense	36,307	34,955	1,352	
Other	97,419	95,879	1,540	
Total other operations and maintenance expense	$ 170,903	$ 171,629	$ (726)	

---

(1) Primarily due to (i) an insurance claim receivable recognized in 1999 for expenses of a major overhaul of gas turbines at a local plant that were recognized in prior periods and (ii) unscheduled maintenance due to a mechanical problem with a turbine shaft in 2000.
(2) Primarily due to increased project costs related to new customers.
(3) Primarily due to increased expenses for (i) a one-time environmental assessment at Company-owned generating plants and (ii) new maintenance agreements on computer equipment.
(4) Primarily due to (i) the 1999 reversal of a receivable related to anticipated refunds on medical payments and (ii) increased medical expenses in 1999 with no comparable activity in 2000.
(5) Primarily due to reduced professional fees.
(6) Primarily due to a cumulative year-to-date adjustment in 1999 that reduced other postretirement benefits as a result of a revised actuarial valuation.

The New Mexico Settlement charge of $6.3 million in 1998 represents the write-off of the book value of undercollected fuel revenues in the Company's New Mexico jurisdiction.

Depreciation and amortization expense decreased $3.9 million in 2000 compared to 1999 primarily due to a change in the estimated depreciable life of the plant investment related to the decommissioning of Palo Verde. The increase of $1.1 million in 1999 compared to 1998 was primarily due to increases in depreciable plant balances.

Taxes other than income taxes increased $1.7 million in 2000 compared to 1999 primarily due to (i) a $3.1 million reversal in 1999 of sales tax reserves established in prior years with no comparable amount in 2000 and (ii) an increase in Texas revenue related taxes due to higher operating income in 2000. These increases were partially offset by a $1.7 million decrease in Arizona property taxes as a result of depreciation and a regulatory plant writedown pursuant to the New Mexico Settlement Agreement. The decrease of $2.8 million in 1999 compared to 1998 was primarily due to (i) a $3.1 million reversal in 1999 of sales tax reserves established in prior years and (ii) a decrease in Arizona property taxes as a result of depreciation and a decrease in the assessment ratio in 1999. These decreases were partially offset by (i) an increase in Texas franchise tax resulting from a refund in 1998 with no comparable amount in 1999 and (ii) a 1999 reclassification of payroll taxes related to the 1998 all employee cash bonus.

Other income (deductions) increased $7.0 million in 2000 compared to 1999 primarily due to the accrual in 1999 of $16.5 million to be paid under the settlement agreement with Las Cruces. This increase was partially offset by (i) a decrease in investment income of $3.4 million resulting from the investment of lower levels of cash; (ii) a 1999 adjustment of $1.7 million to the cash value of Company-owned life insurance policies and (iii) a gain realized on the disposition of non-utility property of $2.4 million in 1999 with no comparable activity in 2000. The decrease of $20.7 million in 1999 compared to 1998 was primarily due to (i) the accrual in 1999 of $16.5 million to be paid under the settlement agreement with Las Cruces; (ii) a decrease in investment income of $6.4 million resulting from the investment of lower levels of cash and the investment of a portion of decommissioning trust funds in equity securities, the unrealized gains and losses on which are reported as other comprehensive income; and (iii) a favorable settlement of bankruptcy professional fees of $1.3 million in 1998 with no comparable amount in 1999. These decreases were partially offset by (i) an adjustment of $1.7 million to the cash value of Company-owned life insurance policies, which was not previously recognized due to the uncertainty of recoverability from the insurer; and (ii) a gain realized on the disposition of non-utility property of $2.4 million in 1999 compared to $0.7 million in 1998.

Interest charges decreased $10.0 million in 2000 compared to 1999 primarily due to (i) a reduction in outstanding debt as a result of open market purchases of the Company's first mortgage bonds and (ii) adjustments to postload nuclear fuel to write-off a portion of accumulated interest capitalized prior to 1999. The decrease of $0.7 million in 1999 compared to 1998 was primarily due to a reduction in outstanding debt as a result of open market purchases and redemptions of the Company's first mortgage bonds. This decrease was partially offset by adjustments to postload nuclear fuel to (i) write-off a portion of accumulated interest capitalized prior to 1999 and (ii) discontinue capitalizing interest in 1999.

Income tax expense, excluding the tax effect of extraordinary items, increased $13.3 million in 2000 compared to 1999 primarily due to changes in pretax income, and certain permanent differences including (i) an increase in nondeductible transition costs, (ii) a decrease in the adjustment to the cash value of Company-owned life insurance policies and (iii) a decrease in tax-exempt income. Income tax expense, excluding the tax effect of extraordinary items, decreased $9.1 million in 1999 compared to

1998, primarily due to changes in pretax income, including the accrual under the settlement agreement with Las Cruces, and certain permanent differences including an adjustment to the cash value of Company-owned life insurance policies and tax-exempt income.

Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit, represents the payment of premiums on debt extinguishments and the recognition of unamortized issuance expenses on that debt during 2000 and 1999 and unclaimed and undistributed funds designated for the payment of preconfirmation bankruptcy claims which reverted to the Company in 1998.

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.

The Financial Accounting Standards Board (the "FASB") has issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). SFAS 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recognition of derivatives as either assets or liabilities in the balance sheet with the measurement of those instruments at fair value. The Company has adopted SFAS 133, as amended, as of January 1, 2001. The Company completed the review of all of its significant financial instruments and commodity contracts, including fuel supply, purchased power and power sales contracts. The Company has determined that certain of these commodity contracts meet the "normal purchases and normal sales" exclusion provided in SFAS 133 and, as such, are not required to be accounted for as a derivative, pursuant to SFAS 133. Based on that review, the Company believes that the adoption of SFAS 133 will not have a material impact on the Company's financial position or results of operations.

In December 2000 and March 2001, the FASB's Derivatives Implementation Group (the "DIG") discussed whether certain electricity and gas forward contracts that include characteristics of written or purchased options should qualify for the "normal purchases and normal sales" scope exception. The DIG also discussed whether contracts that are subject to "bookout" (net settlement among counterparties in a series of sales and purchases of electricity) meet this exclusion. If the DIG reaches conclusions (and the FASB approves such conclusions) that are contrary to the Company's views, the Company may have to account for certain of its commodity contracts, including certain fuel supply, purchased power and power sales contracts, as derivatives pursuant to SFAS 133. Any such change may be material to the Company's financial position or results of operations and would be accounted for as a cumulative-effect-type adjustment as of the first day of the first fiscal quarter following the date that the FASB-cleared guidance is posted on the FASB's website, unless directed otherwise by the FASB.

Additionally, there remain a number of other unresolved issues before the DIG, the ultimate resolution of which may impact the application of SFAS 133.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The following discussion regarding the Company's market-risk sensitive instruments contains forward-looking information involving risks and uncertainties. The statements regarding potential gains and losses are only estimates of what could occur in the future. Actual future results may differ materially from those estimates presented due to the characteristics of the risks and uncertainties involved.

The Company is exposed to market risk due to changes in interest rates, equity prices and commodity prices. Substantially all financial instruments and positions held by the Company described below are held for purposes other than trading.

Interest Rate Risk

The Company's interest rate risk relates primarily to debt financing issued to fund nuclear fuel requirements. Currently, the Company does not have a plan to issue long-term debt within the next five years. The Company's long-term debt obligations are all fixed-rate obligations with varying maturities, except for nuclear fuel financing, which is based on floating rates. The interest rate risk related to nuclear fuel financing is substantially mitigated through the operation of the Texas Commission rules and the Company's energy cost recovery clauses ("fuel clauses") in certain wholesale rates. Under these rules and fuel clauses, energy costs, including interest expense on nuclear fuel financing, are passed through to customers. However, in the Company's New Mexico service area and under certain wholesale contracts, energy costs are included in the Company's base rates and are not subject to periodic reconciliation or adjustment for past fluctuations in such costs. The Company is preparing a rate case filing with the New Mexico Commission to request a base rate increase in New Mexico to recover higher future energy costs upon the expiration of a rate freeze in April 2001. The near-term losses from reasonably possible near-term increases in interest rates related to the nuclear fuel financing portion of energy costs incurred for these customers would not be material to the Company's financial position, results of operations and cash flows.

In 1999 the Company's interest rate risk also included the pollution control revenue bonds with an aggregate principal amount of $193.1 million. These pollution control revenue bonds were variable-rate bonds until their remarketing in the third quarter of 2000. The near-term losses in 1999 from reasonably possible near-term increases in interest rates would not have been material to the Company's financial position, results of operations and cash flows.

The Company's decommissioning trust funds consist of equity securities and fixed income instruments and are carried at market value. The Company faces interest rate risk on the fixed income instruments, which consist primarily of municipal, federal and corporate bonds and which were valued at $27.6 million and $24.2 million as of December 31, 2000 and 1999, respectively. A hypothetical 10% increase in interest rates would result in a $2.8 million and $2.4 million reduction in fair value at December 31, 2000 and 1999, respectively.

Equity Price Risk

The Company's decommissioning trust funds include marketable equity securities of approximately $32.6 million and $32.9 million at December 31, 2000 and 1999, respectively. A hypothetical 20% decrease in equity prices would result in a $6.5 million and $6.6 million reduction in fair value at December 31, 2000 and 1999, respectively.

Commodity Price Risk

The Company utilizes contracts of various durations for the purchase of natural gas, uranium concentrates and coal to effectively manage its available fuel portfolio. These agreements contain fixed and variable pricing provisions and are settled by physical delivery. The fuel contracts with variable pricing provisions, as well as substantially all of the Company's purchased power requirements, are exposed to fluctuations in prices due to unpredictable factors, including weather, which impact supply and demand. Natural gas and purchased power prices have increased significantly since May 2000. Furthermore, these prices are expected to remain high on average over the next twelve months.

The Company's exposure to fuel and purchased power price risk is substantially mitigated through the operation of the Texas Commission rules and the Company's fuel clauses, as described above. However, in the Company's New Mexico service area and under certain wholesale contracts, energy costs are included in the Company's base rates and are not subject to periodic reconciliation or adjustment for past fluctuations in such costs. The Company is preparing a rate case filing with the New Mexico Commission to request a base rate increase in New Mexico to recover higher future energy costs upon the expiration of a rate freeze in April 2001. The Company's average energy costs incurred for these customers currently exceed the energy costs that were incorporated into the applicable rates. Therefore, the Company is exposed to commodity price risk on energy costs (primarily comprised of natural gas and purchased power) that are related to these sales of electricity. See Part I, Item 1, "Business – Regulation – New Mexico Regulatory Matters – Fuel." If the Company's average energy costs remain at levels experienced during the last half of 2000 and sales volume does not change, the Company would incur increased energy expenses which may not be recovered from New Mexico and certain wholesale customers over the next twelve months of approximately $3.2 million, net of tax, as compared to actual energy expenses incurred in 2000. Additionally, a hypothetical 10% increase in the market-based natural gas and purchased power costs incurred during the last half of 2000 would result in an additional annualized after-tax increase in natural gas and purchased power costs of approximately $1.2 million and $1.0 million, respectively, that may not be recoverable. Prior to the significant 2000 price increases in natural gas and purchased power, the Company's commodity price risk exposure for New Mexico fuel costs for near-term losses from reasonably possible near-term increases in market prices would not have been material to the Company's financial position, results of operations and cash flows.

In the normal course of business, the Company utilizes contracts of various durations for the forward sales and purchases of electricity to effectively manage its available generating capacity and supply needs. Such contracts include forward contracts for the sale of generating capacity and energy during periods when the Company's available power resources are expected to exceed the requirements of its native load and sales for resale. They may also include forward contracts for the purchase of wholesale capacity and energy during periods when the market price of electricity is below the Company's expected incremental power production costs or to supplement the Company's generating capacity when demand is anticipated to exceed such capacity. As of December 31, 2000, the Company had entered into forward sales and purchase contracts for energy with aggregate contract values of approximately $11.7 million and $7.1 million, respectively. A hypothetical 10% increase in the market price of wholesale electricity would result in a $1.2 million decrease in the fair value of the forward sales contracts. A hypothetical 10% decrease in the market price of wholesale electricity would result in a $0.7 million decrease in the fair value of the forward purchase contracts. At December 31, 1999, there were no material open positions in these activities.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

The Shareholders and Board of Directors
El Paso Electric Company

We have audited the accompanying balance sheets of El Paso Electric Company as of December 31, 2000 and 1999, and the related statements of operations, comprehensive operations, changes in common stock equity and cash flows for the years ended December 31, 2000, 1999 and 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 financial statements referred to above present fairly, in all material respects, the financial position of El Paso Electric Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for the years ended December 31, 2000, 1999 and 1998, in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

El Paso, Texas
March 8, 2001

EL PASO ELECTRIC COMPANY
BALANCE SHEETS

ASSETS (In thousands)	December 31, 2000	December 31, 1999
Utility plant:		
Electric plant in service	$ 1,659,539	$ 1,626,224
Less accumulated depreciation and amortization	391,675	329,165
Net plant in service	1,267,864	1,297,059
Construction work in progress	72,580	61,842
Nuclear fuel; includes fuel in process of $10,430 and $8,994, respectively	75,880	78,891
Less accumulated amortization	36,289	39,355
Net nuclear fuel	39,591	39,536
Net utility plant	1,380,035	1,398,437
Current assets:		
Cash and temporary investments	11,344	37,234
Accounts receivable, principally trade, net of allowance for doubtful accounts of $3,293 and $2,429, respectively	86,647	62,036
Inventories, at cost	24,845	25,963
Net undercollection of fuel revenues	15,733	–
Prepayments and other	9,165	8,832
Total current assets	147,734	134,065
Long-term contract receivable	10,709	17,237
Deferred charges and other assets:		
Decommissioning trust fund	60,176	57,117
Other	17,890	19,035
Total deferred charges and other assets	78,066	76,152
Total assets	$ 1,616,544	$ 1,625,891

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands except for share data)	December 31, 2000	December 31, 1999
Capitalization:		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 60,429,107 and 60,200,921 shares issued, and 276,066 and 258,788 restricted shares, respectively	$ 60,705	$ 60,460
Capital in excess of stated value	244,528	242,702
Unearned compensation – restricted stock awards	(1,309)	(1,149)
Retained earnings	202,116	143,724
Accumulated other comprehensive income (net unrealized gains on marketable securities), net of tax	2,902	4,179
	508,942	449,916
Treasury stock, 9,230,786 and 3,199,927, shares respectively; at cost	(96,908)	(28,658)
Common stock equity	412,034	421,258
Long-term debt	715,058	788,576
Financing and capital lease obligations	25,165	23,031
Total capitalization	1,152,257	1,232,865
Current liabilities:		
Current maturities of long-term debt and financing and capital lease obligations	57,663	27,042
Accounts payable, principally trade	39,799	22,241
Litigation settlement payable	–	16,500
Taxes accrued other than federal income taxes	17,054	17,617
Interest accrued	16,528	17,022
Net overcollection of fuel revenues	–	2,640
Other	15,930	12,946
Total current liabilities	146,974	116,008
Deferred credits and other liabilities:		
Decommissioning liability	128,129	120,875
Accrued postretirement benefit liability	81,784	81,176
Accumulated deferred income taxes, net	47,279	12,503
Accrued pension liability	31,134	32,476
Other	28,987	29,988
Total deferred credits and other liabilities	317,313	277,018
Commitments and contingencies		
Total capitalization and liabilities	$ 1,616,544	$ 1,625,891

See accompanying notes to financial statements.

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

	Years Ended December 31, 2000	1999	1998
Operating revenues	$ 701,649	$ 570,469	$ 601,823
Energy expenses:			
Fuel	159,547	104,398	109,450
Coal mine reclamation adjustment	–	(6,601)	–
Purchased and interchanged power	61,217	12,000	20,610
	220,764	109,797	130,060
Operating revenues net of energy expenses	480,885	460,672	471,763
Other operating expenses:			
Other operations	138,956	134,596	136,674
Maintenance	41,800	36,307	34,955
New Mexico Settlement charge	–	–	6,272
Depreciation and amortization	87,001	90,934	89,813
Taxes other than income taxes	43,154	41,499	44,332
	310,911	303,336	312,046
Operating income	169,974	157,336	159,717
Other income (deductions):			
Investment income	3,482	6,928	13,334
Litigation settlements	(1,000)	(16,500)	–
Settlement of bankruptcy professional fees	–	–	1,261
Other, net	(2,271)	2,766	(736)
	211	(6,806)	13,859
Income before interest charges	170,185	150,530	173,576
Interest charges (credits):			
Interest on long-term debt	67,249	76,634	80,967
Other interest	7,632	7,697	7,198
Interest capitalized and deferred	(3,756)	(3,242)	(6,400)
	71,125	81,089	81,765
Income before income taxes and extraordinary item	99,060	69,441	91,811
Income tax expense	38,896	25,632	34,738
Income before extraordinary item	60,164	43,809	57,073
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(1,772)	(3,336)	3,343
Net income	58,392	40,473	60,416
Preferred stock:			
Dividend requirements	–	2,616	14,707
Redemption costs	–	9,581	–
Net income applicable to common stock	$ 58,392	$ 28,276	$ 45,709
Basic earnings per common share:			
Income before extraordinary item	$ 1.11	$ 0.53	$ 0.70
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(0.03)	(0.05)	0.06
Net income	$ 1.08	$ 0.48	$ 0.76
Diluted earnings per common share:			
Income before extraordinary item	$ 1.09	$ 0.53	$ 0.70
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	(0.03)	(0.06)	0.05
Net income	$ 1.06	$ 0.47	$ 0.75
Weighted average number of common shares outstanding	54,183,915	59,349,468	60,168,234
Weighted average number of common shares and dilutive potential common shares outstanding	55,001,625	59,731,649	60,633,298

See accompanying notes to financial statements.

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

	Years Ended December 31,		
	2000	1999	1998
Net income	$ 58,392	$ 40,473	$ 60,416
Other comprehensive income (loss):			
Net unrealized gains (losses) on marketable securities, net of income tax benefit (expense) of $688, $(1,658) and $(690), respectively	(1,277)	3,078	1,285
Comprehensive income	57,115	43,551	61,701
Preferred stock:			
Dividend requirements	–	2,616	14,707
Redemption costs	–	9,581	–
Comprehensive income applicable to common stock	$ 57,115	$ 31,354	$ 46,994

See accompanying notes to financial statements.

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

	Common Stock Shares	Common Stock Amount	Capital in Excess of Stated Value	Unearned Compensation – Restricted Stock Awards	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Common Stock Equity
Balances at December 31, 1997	60,256,438	$ 60,256	$241,222	$ (1,138)	$ 69,484	$ (184)	$ –	$369,640
Grants of restricted common stock	26,675	27	169	(196)				–
Amortization of unearned compensation				709				709
Stock awards withheld for taxes	(10,843)	(11)	(54)					(65)
Forfeitures of restricted common stock	(1,908)	(2)	(12)	14				–
Preferred stock dividends					(14,707)			(14,707)
Net income					60,416			60,416
Other comprehensive income						1,285		1,285
Balances at December 31, 1998	60,270,362	60,270	241,325	(611)	115,193	1,101	–	417,278
Grants of restricted common stock	210,744	211	1,505	(1,716)				–
Amortization of unearned compensation				1,167				1,167
Stock awards withheld for taxes	(19,965)	(20)	(118)					(138)
Forfeitures of restricted common stock	(1,432)	(1)	(10)	11				–
Preferred stock dividends					(2,616)			(2,616)
Preferred stock redemption					(9,581)			(9,581)
Capital stock adjustment					255			255
Net income					40,473			40,473
Other comprehensive income						3,078		3,078
Treasury stock, 3,199,927 shares; at cost							(28,658)	(28,658)
Balances at December 31, 1999	60,459,709	60,460	242,702	(1,149)	143,724	4,179	(28,658)	421,258
Grants of restricted common stock	177,269	177	1,584	(1,761)				–
Stock issued upon exercise of options	93,955	94	406					500
Amortization of unearned compensation				1,601				1,601
Stock awards withheld for taxes	(25,760)	(26)	(164)					(190)
Net income					58,392			58,392
Other comprehensive loss						(1,277)		(1,277)
Treasury stock, 6,030,859 shares; at cost							(68,250)	(68,250)
Balances at December 31, 2000	60,705,173	$ 60,705	$244,528	$ (1,309)	$ 202,116	$ 2,902	$ (96,908)	$412,034

See accompanying notes to financial statements.

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

	Years Ended December 31,		
	2000	1999	1998
Cash Flows From Operating Activities:			
Net income	$ 58,392	$ 40,473	$ 60,416
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization of electric plant in service	87,001	90,934	89,813
Amortization of nuclear fuel	17,125	17,658	21,804
Deferred income taxes, net	36,590	23,490	29,854
Coal mine reclamation adjustment	–	(6,601)	–
New Mexico Settlement charge	–	–	6,272
Extraordinary (gain) loss on extinguishments of debt, net of income tax expense (benefit)	1,772	3,336	(3,343)
Amortization and accretion of interest costs	9,390	9,158	8,796
Other	3,246	6,976	2,476
Change in:			
Accounts receivable	(24,611)	2,699	(5,775)
Inventories	1,118	1,574	(407)
Prepayments and other	(333)	8,064	(4,479)
Long-term contract receivable	6,528	5,902	4,520
Accounts payable	17,558	(8,894)	6,178
Litigation settlement payable	(16,500)	16,500	–
Taxes accrued other than federal income taxes	(563)	(2,699)	1,024
Interest accrued	(494)	(3,390)	(760)
Net under/overcollection of fuel revenues	(18,373)	8	10,230
Other current liabilities	2,984	(3,833)	1,882
Deferred charges and credits	(1,975)	(7,156)	4,734
Net cash provided by operating activities	178,855	194,199	233,235
Cash Flows From Investing Activities:			
Cash additions to utility property, plant and equipment	(66,960)	(53,705)	(49,787)
Cash additions to nuclear fuel	(16,502)	(16,593)	(15,409)
Interest capitalized:			
Utility property, plant and equipment	(3,078)	(2,618)	(2,380)
Nuclear fuel	(678)	(624)	(4,020)
Investment in decommissioning trust fund	(5,026)	(5,656)	(6,312)
Other investing activities	(182)	(935)	(2,623)
Net cash used for investing activities	(92,426)	(80,131)	(80,531)
Cash Flows From Financing Activities:			
Treasury stock	(67,750)	(28,658)	–
Repurchases of and payments on long-term debt	(40,558)	(124,272)	(30,542)
Nuclear fuel financing obligations:			
Proceeds	19,943	19,907	19,438
Payments	(20,077)	(20,930)	(22,121)
Redemption of preferred stock	–	(148,937)	–
Preferred stock dividend payment	–	(1,328)	–
Payments on capital lease obligations	(1,688)	(1,540)	(1,400)
Other financing activities	(2,189)	(226)	(156)
Net cash used for financing activities	(112,319)	(305,984)	(34,781)
Net (decrease) increase in cash and temporary investments	(25,890)	(191,916)	117,923
Cash and temporary investments at beginning of period	37,234	229,150	111,227
Cash and temporary investments at end of period	$ 11,344	$ 37,234	$ 229,150

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

A. Summary of Significant Accounting Policies

General. El Paso Electric Company (the "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 wholesale customers in Texas, New Mexico, California and Mexico.

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"). The Company determined that it does not meet the criteria for the application of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation," and accordingly does not report the effects of certain actions of regulators as assets or liabilities unless such actions result in assets or liabilities under generally accepted accounting principles for commercial enterprises in general.

Comprehensive Income. Certain gains and losses that are not recognized currently in the 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 $324 million of reorganization value allocated primarily to net transmission, distribution and general plant in service. This amount is being depreciated over the ten-year period of a rate settlement (the "Texas Rate Stipulation"). Based on a provision in the Texas Restructuring Law allowing recovery of nuclear decommissioning costs over the service lives of nuclear plants, as of January 1, 2000, the Company changed the estimated useful life of the plant investment of approximately $59 million for the Texas jurisdiction related to the decommissioning of Palo Verde. Previously, this decommissioning portion of Palo Verde plant costs had been depreciated over 10 years. The change in the estimated useful life resulted in a decrease in depreciation expense and an increase in net income of $3.0 million, net of tax, or $0.06 diluted earnings per common share in 2000. 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 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 Company recorded a liability for the present value of the estimated decommissioning costs for the Company's interest in Palo Verde using a cost inflation rate of 3% and a discount rate of 6%.

Accretion of the decommissioning liability is charged to other interest charges in the statements of operations.

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 expensing its share of costs, as incurred, associated with on-site spent fuel storage at Palo Verde. See Note C.

Impairment of Long-Lived Assets. The Company evaluates impairment of its long-lived assets and certain intangible assets whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. An asset is deemed impaired if the sum of the expected future cash flows is less than the carrying amount of the asset.

Capitalized Interest. The Company capitalizes, to construction work in progress and nuclear fuel in process, interest cost calculated in accordance with SFAS No. 34, "Capitalization of Interest Cost."

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.

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. The Company's recovery of energy expenses in Texas is subject to periodic reconciliations of actual energy expenses incurred to actual fuel revenues collected. Rate tariffs currently applicable to certain FERC jurisdictional customers contain energy cost adjustment provisions designed to recover the Company's actual energy expenses. The difference between energy expenses incurred and fuel revenues charged to the Company's Texas and applicable FERC jurisdictional customers, as determined under Texas Commission rules and FERC rate tariffs, is reflected as net over/undercollection of fuel revenues in the balance sheets.

Federal Income Taxes. The Company accounts for federal 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 bases 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 common share is computed by dividing net income, after deducting the preferred stock dividend requirements, by the weighted average number of common shares outstanding. Diluted earnings per common share is computed by dividing net income, after deducting the preferred stock dividend requirements, by the weighted average number of common shares and dilutive potential common shares outstanding.

Benefit Plans. See Note J for accounting policies regarding the Company's retirement plans and postretirement benefits.

Stock Options and Restricted Stock. The Company has a long-term incentive plan which reserves shares of common stock for issuance to officers, key employees and non-employee directors through the award or grant of stock options and restricted stock. The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Accordingly, compensation expense is recognized for the intrinsic value, if any, of option grants at measurement date ratably over the vesting period of the options. Compensation expense for the restricted stock awards is recognized for the fair value of the shares at the award date ratably over the restriction period. Unearned compensation related to restricted stock awards is shown as a reduction of common stock equity.

Reclassifications. Certain amounts in the financial statements for 1999 and 1998 have been reclassified to conform with the 2000 presentation.

Supplemental Statements of Cash Flows Disclosures (in thousands)

	Years Ended December 31,		
	2000	1999	1998
Cash paid for:			
Interest on long-term debt (1)	$ 64,141	$ 72,600	$ 74,537
Income taxes	1,200	1,882	2,900
Other interest	237	702	436
Reorganization items – professional fees and other	–	–	4,310
Non-cash investing and financing activities:			
Grants of restricted shares of common stock	1,761	1,716	196
Acquisition of treasury stock for options exercised	500	–	–
Issuance of preferred stock for pay-in-kind dividends	–	3,867	14,425

(1) Includes interest on bonds, letter of credit fees related to bonds, and interest on nuclear fuel financing not capitalized.

B. Regulation

General

In 1999, both Texas and New Mexico enacted electric utility industry restructuring laws requiring competition in certain functions of the industry and ultimately in the Company's service area. Competition in New Mexico was scheduled to begin on January 1, 2002 under the New Mexico Restructuring Law. On March 8, 2001, the New Mexico Restructuring Law was amended to delay the start of competition for five years until January 1, 2007. The amended New Mexico Restructuring Law permits utilities to form holding companies and participate in unregulated power production, provided the utility does not separate its transmission and distribution activities from its existing generation activities. Under the Texas Restructuring Law, the Company's Texas service area is exempt from competition until the expiration of the Freeze Period in August 2005.

The Company continues to work to become more competitive in response to these restructuring laws as well as other regulatory, economic and technological changes occurring throughout the industry. Deregulation of the production of electricity and related services and increasing customer demand for lower priced electricity and other energy services have accelerated the industry's movement toward more competitive pricing and cost structures. These competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets. Once deregulation is initiated in other portions of Texas in January 2002, the Company may face increasing pressure on its retail rates and its rate freeze under the Texas Rate Stipulation. The Company's results of operations and cash flows may be adversely affected if it cannot maintain its current retail rates.

During 2000, the cost of natural gas and purchased power substantially increased and these increased energy costs may continue in 2001. Under the Company's New Mexico Settlement Agreement, which was in effect during 2000 and will remain in effect through April 2001, the Company bears the risk and benefit of any increases or decreases in energy costs related to its New Mexico retail customers. Upon the expiration of the New Mexico Settlement Agreement, the Company will seek to increase its New Mexico rates to include the higher energy costs that the Company expects to incur. The Company cannot predict whether or to what extent the New Mexico Commission will allow the Company to increase rates to recover the increased energy costs. See "New Mexico Regulatory Matters – Fuel" below.

Texas Regulatory Matters

The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas 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 in Texas and jurisdiction over certain other activities of the Company. The decisions of the Texas Commission are subject to judicial review.

Deregulation. The Texas Restructuring Law requires an electric utility to separate its power generation activities from its transmission and distribution activities by January 1, 2002. The Texas Restructuring Law specifically recognizes and preserves the substantial benefits the Company bargained for in its Texas Rate Stipulation and Texas Settlement Agreement, exempting the Company's Texas service area from retail competition, and preserving rates at their current levels until the end of the Freeze Period. At the end of the Freeze Period, the Company will be subject to retail competition and will have no further claim for recovery of stranded costs. The Company believes that its continued ability to provide bundled electric service at current rates in its Texas service area will allow the Company to collect its Texas jurisdictional stranded costs.

Although the Company is not subject to the Texas restructuring requirements until the expiration of the Freeze Period, the Company sought Texas Commission approval of the Company's corporate restructuring in anticipation of complying with the restructuring requirements of the New Mexico Restructuring Law. In December 2000, the Texas Commission approved the Company's corporate restructuring plan. However, the amended New Mexico Restructuring Law now prohibits the separation of the Company's generation activities from its transmission and distribution activities until January 1, 2007, directly conflicting with the Texas Restructuring Law requiring separation of these activities in 2005. Accordingly, in either 2004 or 2005, the Company will seek New Mexico Commission approval to separate the Company's generation activities from its transmission and distribution activities to allow the Company to comply with the Texas Restructuring Law requirements.

Texas Rate Stipulation and Texas Settlement Agreement. The Texas Rate Stipulation and Texas Settlement Agreement govern the Company's rates for its Texas customers, but do not deprive the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Texas Rate Stipulation (other than the Texas Office of Public Utility Counsel and the State of Texas) agreed to not seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking base rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Texas Rate Stipulation retain all rights provided in the Texas Rate Stipulation, the right to participate as a party in any proceeding related to the merger, and the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings.

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 increases or decreases in energy costs associated with the provision of electricity as well as seek recovery of past undercollections of fuel revenues. Beginning in the second quarter of 2000, the Company's average energy costs exceeded its fuel factor due to substantial increases in the price of natural gas and purchased power. Accordingly, the Company had a significant underrecovery of its actual energy expenses. On August 1, 2000, the Company filed a petition with the Texas Commission to increase its fixed fuel factor from $0.01435 per kWh to $0.02186 per kWh. The Company was granted interim approval to implement the increased fuel factor with the first billing cycle in September 2000. The Texas Commission granted final approval of the increased fuel factor on November 1, 2000. The new fuel factor increased fuel revenue collections by $12.2 million in 2000.

On January 8, 2001, the Company filed a second petition with the Texas Commission for an additional fuel factor increase and a 12-month fuel surcharge beginning April 2001. The Company's requested fuel factor would increase from $0.02186 per kWh to $0.02915 per kWh. The requested surcharge seeks to recover $22.4 million in underrecovered energy expenses the Company incurred in 2000, including interest. The Company proposes to spread this surcharge recovery over 12 months to mitigate the impact on customers' monthly bills. The Texas Commission traditionally renders a decision within 90 days of the Company's filing, but the Company requested interim approval of its proposed fuel factor if a final order is not issued in early April 2001.

Any fuel surcharge granted to the Company, as well as the Company's other energy expenses, will be subject to final review by the Texas Commission in the Company's next fuel reconciliation proceeding, which is expected to be filed by the middle of 2002. The Texas Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the prudence of fuel and purchased power expenses.

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 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. The Company has calculated approximately $19.7 million of performance rewards for the three-year periods ended December 31, 2000, 1999 and 1998. These rewards are included, along with energy costs incurred, as part of the Texas Commission's review during the periodic fuel reconciliation proceedings discussed above. Performance rewards are not recorded on the Company's books until the Texas Commission has ordered a final determination in a fuel reconciliation proceeding. 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 March 2001, the New Mexico Legislature amended the New Mexico Restructuring Law to postpone deregulation in New Mexico until January 1, 2007. The amended New Mexico Restructuring Law permits utilities to form holding companies and through the holding company participate in unregulated power production, provided the utility does not separate its transmission and distribution activities from its existing generation activities. The Company is currently evaluating possible benefits, if any, of forming a holding company without separating its power generation activities from its transmission and distribution activities.

The amended New Mexico Restructuring Law prohibiting the separation of the Company's generation activities from its transmission and distribution activities until January 1, 2007, directly conflicts with the Texas Restructuring Law requiring separation of these activities in 2005. Accordingly, in either 2004 or 2005, the Company will seek New Mexico Commission approval to separate the Company's generation activities from its transmission and distribution activities to allow the Company to comply with the Texas Restructuring Law requirements.

Due to the uncertainty of the timing of deregulation in New Mexico, on October 12, 2000, the Company filed with the New Mexico Commission an application to form a wholly-owned energy services subsidiary. In December 2000, the New Mexico Commission approved the Company's application and authorized the Company to invest up to $20 million in the subsidiary. Following this approval, the Company created MiraSol Energy Services, Inc., which began operation in March 2001.

The New Mexico Restructuring Law allows the Company to recover reasonable, prudent and unmitigated costs that the Company would not have incurred but for its compliance with the New Mexico Restructuring Law. These transition costs do not include stranded costs, costs the Company can collect under federally approved rates or rates approved by the New Mexico Commission, or any costs the Company would have incurred regardless of the New Mexico Restructuring Law. The March 2001 amendment to the New Mexico Restructuring Law did not address the recovery of transition costs spent to date. The Company cannot predict whether and to what extent the New Mexico Commission will allow the Company to recover these transition costs during the five year delay. Such costs, to the extent they are not capitalizable as fixed assets, are expensed as incurred.

Fuel. The New Mexico Settlement Agreement entered into in October 1998 incorporated the then existing fuel factor into frozen base rates. Accordingly, the Company must absorb any increases or decreases in energy expenses related to its New Mexico retail customers until new rates are approved following the expiration of this rate freeze in April 2001. The Company is preparing a rate case filing with the New Mexico Commission requesting an increase in the Company's rates beginning May 2001 reflecting current increases in natural gas and purchased power prices. The Company may also request recovery of increases in capital costs related to its New Mexico retail customers as part of this rate case filing. The Company cannot predict what rate increase, if any, the New Mexico Commission may approve or when the New Mexico Commission will ultimately rule on the Company's rate case.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The Company is subject to regulation by the FERC in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

In anticipation of complying with the New Mexico Restructuring Law, the Company filed its Application for Authorization to Transfer Certain Assets and Approval for Certain Securities Transactions with the FERC seeking the necessary FERC approvals for its corporate restructuring. On October 4, 2000, the FERC issued its Order Authorizing Disposition of Jurisdictional Facilities allowing the transfer of assets necessary to implement the Company's corporate restructuring. On October 13, 2000, the FERC issued its order authorizing the securities transactions related to the Company's corporate restructuring.

Fuel. Under FERC regulations, the Company's fuel factor is adjusted monthly for almost all FERC jurisdictional customers. Accordingly, any increases or decreases in energy expenses immediately flow through to such customers.

RTOs. On December 15, 1999, the FERC approved its final rule ("Order 2000") on Regional Transmission Organizations ("RTOs"). Order 2000 strongly encourages, but does not require, public utilities to form and join RTOs. Order 2000 also proposes RTO startup by December 15, 2001. The Company is an active participant in the development of the Desert Southwest Transmission and Reliability Operator ("Desert Star"). The Company believes Desert Star will qualify as an RTO under Order 2000. The Company intends, subject to the resolution of outstanding issues, to participate in Desert Star. As a participating transmission owner, the Company will transfer operations of its transmission system to Desert Star. The Desert Star proposal was submitted to the FERC on October 15, 2000. On March 1, 2001, the Desert Star proposal was updated to inform the FERC that the start of Desert Star operations will be delayed. Desert Star is currently scheduled to become operational by January 1, 2003. If Desert Star should fail to become operational, the Company would seek to participate in another RTO similar to Desert Star.

Department of Energy. The DOE regulates the Company's exports of power to the Comision Federal de Electricidad de Mexico ("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. The DOE is authorized to assess operators of nuclear generating facilities for 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 Note C for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission. The Nuclear Regulatory Commission ("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.

In anticipation of complying with the New Mexico Restructuring Law, the Company filed its Application for NRC consent to the indirect transfer of control of the Company's minority non-operating ownership interest in Palo Verde as part of the Company's corporate restructuring. In December 2000, the NRC granted all requested approvals.

Sales for Resale

During 2000, the Company provided the Imperial Irrigation District ("IID") with 100 MW of firm capacity and associated energy and 50 MW of system contingent capacity and associated energy pursuant to a 17-year agreement which expires April 30, 2002. In 2001, the Company will provide IID with similar amounts of capacity and associated energy. The Company also provided Texas-New Mexico Power ("TNP") with up to 25 MW of firm capacity and associated energy pursuant to an agreement that expires December 31, 2002. The contract allows TNP to specify a maximum annual amount with one year's notice. For 2001, the Company is contracted to provide TNP up to 25 MW of firm capacity and associated energy. The Company has also contracted to sell 40 MW to CFE during the month of May 2001 and 100 MW during the months of June through September 2001.

C. Palo Verde and Other Jointly-Owned Utility Plant

The Company owns a 15.8% interest in each of the three nuclear generating units and Common Facilities at Palo Verde. The Palo Verde Participants include the Company, five other utilities and Arizona Public Service Company ("APS"), which 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").

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, 2000 and 1999 is as follows (in thousands):

	December 31, 2000		December 31, 1999	
	Palo Verde Station	Other	Palo Verde Station	Other
Electric plant in service	$ 599,798	$ 182,982	$ 594,755	$ 180,196
Accumulated depreciation	(102,862)	(70,097)	(88,004)	(55,526)
Construction work in progress	19,405	1,681	16,502	3,373

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 proportionate share of fuel, other operations, maintenance and capital costs, which, except capital costs, are included in the corresponding expense captions in the statements of operations. The Company's average monthly share of these costs was approximately $7.0 million in 2000. 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, over their estimated useful lives of 40 years (to 2024, 2025 and 2027, respectively). The Company's funding requirements are determined periodically based upon engineering cost estimates performed by outside engineers retained by APS.

In December 1998, the Palo Verde Participants approved an updated decommissioning study. The 1998 study determined that the Company will have to fund approximately $280.5 million (stated in 1998 dollars) to cover its share of decommissioning costs. Cost estimates for decommissioning have increased with each study. The previous cost estimate from a 1995 study determined that the Company would have to fund approximately $229 million (stated in 1995 dollars). The 1998 estimate reflects a 22% increase from the 1995 estimate primarily due to increases in estimated costs for spent fuel storage after operations have ceased. See "Spent Fuel Storage" below.

Although the 1998 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 and a new study is expected to be completed during the fourth quarter of 2001. See "Disposal of Low-Level Radioactive Waste" below.

The Company will recover its current decommissioning cost estimates in Texas through its existing rates during the Freeze Period, and thereafter through a non-bypassable wires charge under the provisions of the Texas Restructuring Law. The rate freeze under the Texas Rate Stipulation and the rate reduction under the Texas Settlement Agreement preclude the Company from seeking a rate increase in Texas to recover increases in decommissioning cost estimates during the Freeze Period. See Note B.

The Company is currently collecting its decommissioning costs estimates in New Mexico under the New Mexico Settlement Agreement, which expires in April 2001. The Company is preparing a rate case filing with the New Mexico Commission and will request recovery of the Company's future New Mexico decommissioning cost estimates through regulated rates after the expiration of the rate freeze under the New Mexico Settlement Agreement. See Note B.

The Company has established external trusts 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, 2000, the fair market value of the trust funds was approximately $60.2 million, which is reflected in the Company's balance sheet in deferred charges and other assets.

Spent Fuel Storage. The spent fuel storage facilities at Palo Verde will have sufficient capacity to store all fuel expected to be discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities are currently being constructed to supplement existing facilities. Spent fuel will be removed from the original facilities as necessary and placed in special storage casks which will be stored at the new facilities until accepted by the DOE for permanent disposal. The alternative facilities will be built in stages to accommodate casks on an as needed basis and are expected to be available for use by the end of 2002.

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. In November 1989, the DOE 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 1998 decommissioning study assumes that only 14 of 333 spent fuel casks will have been removed from Palo Verde by 2037 when title to the remaining spent fuel is assumed to be transferred to the DOE. In January 1997, the Texas Commission established a project to evaluate what, if any, action it should take with regard to payments made to the DOE for funding of the DOE's obligation to start accepting spent nuclear fuel by January 31, 1998. After receiving initial comments, no further action has been taken on the project.

In July 1998, APS filed, on behalf of all Palo Verde Participants, a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking confirmation that findings by the Circuit Court in a prior case brought by Northern States Power regarding the DOE's failure to comply with its obligation to begin accepting spent nuclear fuel would apply to all spent nuclear fuel contract holders. The Circuit Court held APS' petition in abeyance pending the United States Supreme Court's decision to review the Northern States Power case. In November 1998, the Supreme Court denied review of this case. The Circuit Court subsequently dismissed APS' petition after the Circuit Court issued clarifying orders essentially granting the relief sought by APS. APS is monitoring pending litigation between the DOE and other nuclear operators before initiating further legal proceedings or other procedural measures on behalf of the Palo Verde Participants to enforce the DOE's statutory and contractual obligations. The Company is unable to predict the outcome of these matters at this time.

The Company expects to incur significant spent fuel storage costs during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs will be expensed as incurred until an agreement is reached with the DOE for recovery of these costs. However, the Company cannot predict when, if ever, these additional costs will be recovered from the DOE.

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. However, 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.

Steam Generators. Palo Verde has experienced some degradation in the steam generator tubes of each unit. APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS believes its remedial actions have slowed the rate of tube degradation.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during scheduled outages of the Palo Verde units. In December 1999, the Palo Verde Participants unanimously approved installation of the new steam generators in Unit 2. APS currently estimates it will install these new steam generators during the fourth quarter of 2003. The Company's portion of total costs associated with construction and installation of new steam generators in Unit 2 is currently estimated not to exceed $45 million, including approximately $4.9 million of replacement power costs. APS has also stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated lives of 40 years. However, APS is reassessing whether it is economically desirable to replace the steam generators in Units 1 and 3. Any such replacements would also require the unanimous approval of the Palo Verde Participants.

The Texas Rate Stipulation precludes the Company from seeking a rate increase during the Freeze Period to recover additional capital costs associated with the replacement of steam generators. The Company may request recovery of a portion of these costs through regulated rates in New Mexico. See Note B. Finally, the Company cannot assure that it will be able to recover these capital costs through its wholesale power rates or its competitive retail rates that become applicable after the start of competition.

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability under federal law. 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 an assessment to cover any loss in excess of $200 million. Effective August 1998, the maximum 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 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. Finally, the Company 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. 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 3,500,000 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 will 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 2000, 1999 and 1998:

	Number of Shares	Weighted Average Exercise Price
Unexercised options outstanding at December 31, 1997 ...	1,950,000	$ 5.71
Options granted ...	585,000	7.71
Options exercised ...	–	–
Options forfeited ...	–	–
Unexercised options outstanding at December 31, 1998 ...	2,535,000	6.17
Options granted ...	255,644	8.24
Options exercised ...	–	–
Options forfeited ...	–	–
Unexercised options outstanding at December 31, 1999 ...	2,790,644	6.36
Options granted ...	248,159	11.48
Options exercised ...	(93,955)	5.32
Options forfeited ...	–	–
Unexercised options outstanding at December 31, 2000 ...	2,944,848	6.86

Stock option awards provide for vesting periods of up to five years. Stock options outstanding at December 31, 2000 are as follows:

Exercise Price	Number Outstanding	Remaining Life, In Years	Number Exercisable
$ 5.32	706,045	5.3	706,045
5.56	800,000	5.4	680,000
6.56	50,000	6.3	50,000
7.00	300,000	5.4	300,000
7.50	525,000	7.0	210,000
9.50	60,000	7.4	60,000
8.75	100,000	8.0	20,000
7.38	50,000	8.3	50,000
8.13	100,000	8.0	20,000
8.94	2,703	8.6	2,703
9.00	2,941	8.9	2,941
9.81	42,432	9.0	2,432
9.50	50,000	9.3	50,000
10.38	1,492	9.3	1,492
11.19	2,128	9.6	2,128
13.77	2,107	9.9	2,107
12.60	150,000	10.0	—
	2,944,848		2,159,848

The number of stock options exercisable and the weighted average exercise price of these stock options at December 31, 2000, 1999 and 1998 are as follows:

	December 31, 2000	1999	1998
Number of stock options exercisable	2,159,848	1,770,644	1,330,000
Weighted average exercise price.................	$ 6.22	$ 6.06	$ 6.01

The Company has adopted the disclosure-only provisions of SFAS No. 123. Accordingly, because the stock option grants had no intrinsic value at the measurement date, no compensation expense has been recognized. Had compensation expense for the plan been determined based on the fair value at the grant date, consistent with the provisions of SFAS No. 123, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts presented below:

	Years Ended December 31,		
	2000	1999	1998
Net income applicable to common stock (in thousands):			
As reported	$ 58,392	$ 28,276	$ 45,709
Pro forma	57,403	27,380	44,913
Basic earnings per share:			
As reported	1.08	0.48	0.76
Pro forma	1.06	0.46	0.75
Diluted earnings per share:			
As reported	1.06	0.47	0.75
Pro forma	1.04	0.46	0.74

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 2000, 1999 and 1998 are presented below:

	2000	1999	1998
Risk-free interest rate	6.23%	5.01%	5.82%
Expected life, in years	10	10	10
Expected volatility	33.85%	33.98%	7.47%
Expected dividend yield	–	–	–
Fair value per option	$6.78	$4.58	$2.97

Restricted Stock. The Company has awarded vested and unvested restricted stock awards under the 1996 Plan. Restrictions from resale generally lapse, and unvested awards vest, over periods of four to five years. The market value of the unvested restricted stock at the time of grant is recorded as unearned compensation as a separate component of common stock equity and is amortized to expense over the restriction period. During 2000, 1999 and 1998, approximately $1.6 million, $1.2 million and $0.5 million, respectively, related to restricted stock awards was charged to expense. The following table summarizes the vested and unvested restricted stock awards for 2000, 1999 and 1998:

	Vested	Unvested	Total
Restricted shares outstanding at December 31, 1997	86,952	109,452	196,404
Restricted stock awards	–	26,675	26,675
Lapsed restrictions and vesting	(40,488)	(32,698)	(73,186)
Forfeitures	–	(1,908)	(1,908)
Restricted shares outstanding at December 31, 1998	46,464	101,521	147,985
Restricted stock awards	94,619	116,125	210,744
Lapsed restrictions and vesting	(40,488)	(58,021)	(98,509)
Forfeitures	–	(1,432)	(1,432)
Restricted shares outstanding at December 31, 1999	100,595	158,193	258,788
Restricted stock awards	74,539	102,730	177,269
Lapsed restrictions and vesting	(85,107)	(74,884)	(159,991)
Forfeitures	–	–	–
Restricted shares outstanding at December 31, 2000	90,027	186,039	276,066

The weighted average market values at grant date for restricted stock awarded during 2000, 1999 and 1998 are $9.93, $8.14 and $7.32, 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.

Common Stock Repurchase Program

The Company's Board of Directors previously approved two stock repurchase programs allowing the Company to purchase up to twelve million of its outstanding shares of common stock. As of December 31, 2000, the Company had repurchased 9,160,467 shares of common stock under these programs for approximately $96.4 million, including commissions. The Company expects to continue to make purchases primarily in the open market at prevailing prices and will also engage in private transactions, if appropriate. Any 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 Common Share

The reconciliation of basic and diluted earnings per common share before extraordinary item is presented below:

	Year Ended December 31, 2000		
	Income (In thousands)	Shares	Per Common Share
Basic earnings per common share:			
Income before extraordinary item	$ 60,164	54,183,915	$ 1.11
Effect of dilutive securities:			
Unvested restricted stock	–	56,490	
Stock options	–	761,220	
Diluted earnings per common share:			
Income before extraordinary item	$ 60,164	55,001,625	$ 1.09

	Year Ended December 31, 1999		
	Income (In thousands)	Shares	Per Common Share
Income before extraordinary item	$ 43,809		
Less:			
Preferred stock:			
Dividend requirements	2,616		
Redemption costs	9,581		
Basic earnings per common share:			
Income before extraordinary item applicable to common stock	31,612	59,349,468	$ 0.53
Effect of dilutive securities:			
Unvested restricted stock	–	32,729	
Stock options	–	349,452	
Diluted earnings per common share:			
Income before extraordinary item applicable to common stock	$ 31,612	59,731,649	$ 0.53

	Year Ended December 31, 1998		
	Income (In thousands)	Shares	Per Common Share
Income before extraordinary item	$ 57,073		
Less: Preferred stock dividend requirements	14,707		
Basic earnings per common share:			
Income before extraordinary item applicable to common stock	42,366	60,168,234	$ 0.70
Effect of dilutive securities:			
Unvested restricted stock	–	30,309	
Stock options	–	434,755	
Diluted earnings per common share:			
Income before extraordinary item applicable to common stock	$ 42,366	60,633,298	$ 0.70

Options that were excluded from the computation of diluted earnings per common share because the options' exercise price was greater than the average market price of the common shares for the period are listed below:

1) 525,000 options granted January 2, 1998 at an exercise price of $7.50 were excluded for the first quarter of 1998.
2) 60,000 options granted May 29, 1998 at an exercise price of $9.50 were excluded for the second through fourth quarters of 1998, all of 1999 and the first quarter of 2000.
3) 100,000 options granted January 11, 1999 at an exercise price of $8.75 were excluded for the first and second quarters of 1999.
4) 42,432 options granted January 1, 2000 at an exercise price of $9.81 were excluded for the first quarter of 2000.
5) 50,000 options granted March 15, 2000 at an exercise price of $9.50 were excluded for the first quarter of 2000.
6) 2,107 options granted October 1, 2000 at an exercise price of $13.77 were excluded for the fourth quarter of 2000.

E. Preferred Stock

In March 1999, after obtaining required consents of holders of certain of the Company's outstanding debt securities, the Company redeemed its Series A Preferred Stock. The Company paid the redemption price of approximately $139.6 million, accrued cash dividends of $1.3 million, and premium, fees and costs of securing the consents aggregating $9.6 million. The preferred stock had an annual dividend rate of 11.40%.

Following is a summary of the changes in the preferred stock for 1999 and 1998:

	Shares	Amount (In thousands)
Balance at December 31, 1997	1,213,188	$ 121,319
Issuance of pay-in-kind dividends	144,256	14,425
Balance at December 31, 1998	1,357,444	135,744
Issuance of pay-in-kind dividends	38,670	3,867
Redemption of preferred stock	(1,396,114)	(139,611)
Balance at December 31, 1999	–	$ –

F. Long-Term Debt and Financing and Capital Lease Obligations

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

	December 31, 2000	December 31, 1999
	(In thousands)	
Long-Term Debt:		
First Mortgage Bonds (1):		
7.75% Series B, issued 1996, due 2001	$ 34,571	$ 38,571
8.25% Series C, issued 1996, due 2003	84,505	94,505
8.90% Series D, issued 1996, due 2006	207,052	211,402
9.40% Series E, issued 1996, due 2011	230,000	250,498
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
6.150% 1984 Series E refunding bonds, due 2014	37,100	37,100
6.150% 1994 Series A refunding bonds, due 2013	33,300	33,300
Promissory note, due 2007 ($99,000 due in 2001) (3)	465	558
Total long-term debt	749,728	788,669
Financing and Capital Lease Obligations:		
Nuclear fuel ($22,993,000 due in 2001) (4)	48,158	48,292
Turbine lease (5)	–	1,688
Total financing and capital lease obligations	48,158	49,980
Total long-term debt and financing and capital lease obligations	797,886	838,649
Current maturities (amount due within one year)	(57,663)	(27,042)
	$ 740,223	$ 811,607

---

(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 B, C and 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, on or after February 1, 2006. The Company is not required to make mandatory redemption or sinking fund payments with respect to the bonds prior to maturity.

Repurchases, excluding redemption upon maturity, of First Mortgage Bonds made during 2000, 1999 and 1998 are as follows (in thousands):

	Years Ended December 31,		
	2000	1999	1998
7.25% Series A	$ –	$ –	$ 30,227
7.75% Series B	4,000	24,127	–
8.25% Series C	10,000	24,787	–
8.90% Series D	4,350	11,730	–
9.40% Series E	20,498	22,900	–
Total	$ 38,848	$ 83,544	$ 30,227

(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, the bonds may be required to be repurchased at the holder's option or are subject to mandatory redemption. The bonds are redeemable at the option of the Company under certain circumstances. In August 2000, the Company remarketed all four series of the bonds. The interest rates were fixed for five years for the two 6.375% series and two years for the two 6.150% series of bonds. This remarketing allowed the Company to discontinue the letters of credit and related First Mortgage Collateral Series Bonds ("Collateral Series Bonds") that previously enhanced the bond issues. The Company anticipates remarketing the bonds at the end of the two and five year periods, as applicable. The bonds will be shown as current maturities whenever they are within one year of being remarketed.

(3) Promissory Note

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

(4) Nuclear Fuel Financing

The Company has available a $100 million credit facility that expires in February 2002 and provides for up to $70 million for the financing of nuclear fuel and up to $50 million, depending on the balance of nuclear fuel financings, for working capital. This financing 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 Bonds. In the Company's financial statements, the assets and liabilities of the trust are reported as assets and liabilities of the Company.

The $100 million credit facility requires compliance with certain total debt and interest coverage ratios. The Company was in compliance with these requirements throughout 2000.

(5) Copper Turbine Lease Obligation

The Company leases a turbine and certain other related equipment under a lease which was accounted for as a capital lease until its expiration in July 2000. The Company renewed the lease through July 2005, with an extension option for two additional years. The lease is now being accounted for as an operating lease and requires semiannual lease payments of approximately $0.4 million.

As of December 31, 2000, the scheduled maturities for the next five years of long-term debt and financing and capital lease obligations are as follows (in thousands):

2001	$ 57,663
2002	95,669
2003	84,615
2004	116
2005	122,770

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

G. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2000 and 1999 are presented below (in thousands):

	December 31, 2000	December 31, 1999
Deferred tax assets:		
Benefits of federal tax loss carryforwards	$ 105,009	$ 137,752
Pensions and benefits	44,642	45,341
Decommissioning	31,307	29,642
Investment tax credit carryforward	20,410	20,410
Alternative minimum tax credit carryforward	18,862	16,776
Reorganization expenses financed with bonds	8,275	9,247
Other (including benefits of state tax loss carryforwards)	26,632	38,427
Total gross deferred tax assets	255,137	297,595
Less valuation allowance:		
Federal	12,661	12,661
State	14,911	15,659
Total valuation allowance	27,572	28,320
Net deferred tax assets	227,565	269,275
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(245,412)	(256,701)
Other	(29,432)	(25,077)
Total gross deferred tax liabilities	(274,844)	(281,778)
Net accumulated deferred income taxes	$ (47,279)	$ (12,503)

The deferred tax asset valuation allowance decreased by $0.7 million, $0.7 million and $0.8 million in 2000, 1999 and 1998, respectively. These decreases were due to a reduction of unused state net operating loss ("NOL") carryforward benefits, which had valuation allowances recorded against them. Based on the average annual book income before taxes for the prior three years, 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. Approximately $26.8 million of the Company's valuation allowance at December 31, 2000, if subsequently recognized as a tax benefit, would be credited directly to capital in excess of stated value in accordance with Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code."

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

	Years Ended December 31,		
	2000	1999	1998
Income tax expense:			
Federal:			
Current	$ 2,306	$ 2,142	$ 2,884
Deferred	30,881	20,415	27,412
Total federal income tax expense from operations	33,187	22,557	30,296
Deferred included in extraordinary item	(954)	(1,796)	1,800
Total federal income tax expense	$ 32,233	$ 20,761	$ 32,096
State:			
Deferred	$ 5,709	$ 3,075	$ 4,442
Deferred included in extraordinary item	(172)	(331)	344
Total state income tax expense	$ 5,537	$ 2,744	$ 4,786

The current federal income tax expense for 2000, 1999 and 1998 results primarily from the accrual of alternative minimum tax ("AMT"). Deferred federal income tax includes an offsetting AMT benefit of $2.1 million, $2.1 million and $2.8 million for 2000, 1999 and 1998, respectively.

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,		
	2000	1999	1998
Federal income tax expense computed on income at statutory rate	$ 31,719	$ 21,432	$ 32,379
Difference due to:			
Adjustment to cash value of Company-owned life insurance policies	(103)	(608)	–
Transition costs	442	123	–
Other	175	(186)	(283)
Total federal income tax expense	$ 32,233	$ 20,761	$ 32,096
Effective federal income tax rate	35.6%	33.9%	34.7%

As of December 31, 2000, the Company had $300 million of federal tax NOL carryforwards, $20.4 million of investment tax credit ("ITC") carryforwards and $18.9 million of AMT credit carryforwards. If unused, the NOL carryforwards would expire at the end of 2011, the ITC carryforwards would expire in 2001 through 2005, and the AMT credit carryforwards have an unlimited life. The Company had $273.6 million of state NOL carryforwards at December 31, 2000 which, if unused, would expire at the end of 2001. These federal tax attributes are subject to audit by the Internal Revenue Service ("IRS"). The IRS is currently performing an examination of the carryforwards and the 1996 through 1998 federal income tax returns.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

H. Commitments and Contingencies

Sale/Leaseback Indemnification Obligations

Pursuant to the Palo Verde sale/leaseback participation agreements and leases, if the lessors incur additional tax liability or other loss as a result of federal or state tax assessments related to the sale/leaseback transactions, the lessors may have claims against the Company for indemnification.

One of the lessors in the sale/leaseback transactions related to Unit 2 of Palo Verde notified the Company in a prior year that the IRS raised issues, primarily related to ITC claims by the lessor, regarding the income tax treatment of the sale/leaseback transactions. Previous estimates of the potential claims for indemnification from all lessors related to this issue as raised by the IRS were approximately $10.0 million if the IRS prevailed. The Company did not believe it was probable that a loss had been incurred and, therefore, made no provision in the accompanying financial statements related to this matter.

The lessor has advised the Company that it received an informal written notification that the IRS conceded this issue. A formal notification will be included in the final IRS report; however, it is unknown when the final report will be issued.

Power Contracts

As of December 31, 2000, the Company had entered into agreements to sell to Enron 50 MW of firm on-peak energy at Palo Verde for February and March 2001 and 60 MW of firm on-peak energy at Palo Verde from June 2002 through September 2002.

On January 1, 2001, the Company entered into concurrent sales and purchase agreements with Southwestern Public Service Company ("SPS") and Public Service Company of Colorado ("PSCO") for 103 MW of firm off-peak capacity and associated energy monthly through 2001. Under these agreements, the Company will receive energy from SPS through the Eddy County tie and deliver the same amount of energy to PSCO at various other transmission points connected to the Company's generation sources. The sale to PSCO is contingent upon the Company receiving the energy from SPS, and the sales and purchase prices under these agreements are structured such that the Company receives a guaranteed margin. The Company is currently negotiating similar agreements with SPS and PSCO for 2002 through 2005. The Company also entered into an agreement with PSCO whereby PSCO has the option to deliver up to 60 MW of firm on- or off-peak capacity and associated energy to the Company at Palo Verde from January through May 2001 and October through December 2001. If PSCO exercises this option and delivers energy to the Company, the Company agrees to deliver the same amount of energy to PSCO at Four Corners. The option agreement provides the Company with the potential of increasing its sales at the Palo Verde hub.

For 2000, the Company purchased energy in a 50 MW block transaction from SPS in the months of January through May, November and December and 100 MW in the months of June through October. As of December 31, 2000, the Company had entered into an agreement to purchase 60 MW of firm on-peak energy from Enron for June through September 2001. In addition, on January 1, 2001, the Company entered into a contract with SPS to purchase 103 MW of firm on-peak energy monthly in 2001.

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 and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Substantial expenditures may be required to comply with these regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforeseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company.

I. Litigation

The Company is a party to various claims, legal actions and complaints. 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 none of these claims will have a material adverse effect on the financial position, results of operations and cash flows of the Company.

J. 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, are 21 years of age 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 based on the minimum funding amounts required by the Department of Labor and IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company's Non-Qualified Retirement Income Plan is a non-funded defined benefit plan which covers certain former employees of the Company. During 1996, as part of the Company's reorganization, the Company terminated the Non-Qualified Retirement Income Plan with respect to all active employees. The benefit cost for the Non-Qualified Retirement Income Plan is based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan.

The Company accounts for the Retirement Plan and the Non-Qualified Retirement Income Plan under SFAS No. 87, "Employers' Accounting for Pensions," ("SFAS No. 87"). In accordance with SFAS No. 87, the 2000 net periodic benefit cost includes amortization of the unrecognized net gain which exceeded 10% of the benefit obligation at the beginning of the year. The amortization reflects the excess divided by the average remaining service period of active employees expected to receive benefits.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

The amounts recognized in the Company's balance sheets and the funded status of the plans at December 31, 2000 and 1999 are presented below (in thousands):

	Years Ended December 31, 2000 Retirement Income Plan	2000 Non-Qualified Retirement Income Plan	1999 Retirement Income Plan	1999 Non-Qualified Retirement Income Plan
Change in benefit obligation:				
Benefit obligation at beginning of year	$ (87,727)	$ (17,713)	$ (94,140)	$ (19,495)
Service cost	(2,670)	–	(3,155)	–
Interest cost	(6,839)	(1,323)	(6,295)	(1,271)
Actuarial gain (loss)	(9,624)(1)	(901)	12,517 (2)	1,366
Benefits paid	3,547	1,681	3,346	1,687
Benefit obligation at end of year	(103,313)	(18,256)	(87,727)	(17,713)
Change in fair value of plan assets:				
Fair value of plan assets at beginning of year	86,453	–	79,629	–
Actual return on plan assets	3,218	–	7,050	–
Employer contribution	3,327	1,681	3,120	1,687
Benefits paid	(3,547)	(1,681)	(3,346)	(1,687)
Fair value of plan assets at end of year	89,451	–	86,453	–
Funded status	(13,862)	(18,256)	(1,274)	(17,713)
Unrecognized net (gain) loss	984	257	(12,844)	(645)
Balance of additional liability	–	(257)	–	–
Accrued benefit liability	$ (12,878)	$ (18,256)	$ (14,118)	$ (18,358)

(1) Represents a decrease in the discount rate.
(2) Represents a change in actuarial assumptions due to revised census data and an increase in the discount rate.

Weighted average actuarial assumptions used in determining the actuarial present value of the benefit obligations are as follows:

	2000 Retirement Income Plan	2000 Non-Qualified Retirement Income Plan	1999 Retirement Income Plan	1999 Non-Qualified Retirement Income Plan
Discount rate	7.25%	7.25%	7.75%	7.75%
Expected return on plan assets	8.50%	N/A	8.50%	N/A
Rate of compensation increase	5.00%	N/A	5.00%	N/A

Net periodic benefit cost is made up of the components listed below as determined using the projected unit credit actuarial cost method (in thousands):

	Years Ended December 31,		
	2000	1999	1998
Components of net periodic benefit cost:			
Service cost	$ 2,670	$ 3,155	$ 2,879
Interest cost	8,162	7,566	7,165
Expected return on plan assets	(7,307)	(6,597)	(5,820)
Amortization of unrecognized gain	(115)	–	–
Net periodic benefit cost	$ 3,410	$ 4,124	$ 4,224

Weighted average actuarial assumptions used in determining the net periodic benefit costs are as follows:

	2000	1999	1998
Discount rate	7.75%	6.75%	7.00%
Expected return on plan assets	8.50%	8.50%	8.50%
Rate of compensation increase	5.00%	5.00%	5.00%

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 reach retirement age while working for the Company. Those benefits are accounted for under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," ("SFAS No. 106"). In accordance with SFAS No. 106, the 2000 and 1999 net periodic benefit cost includes amortization of the unrecognized net gains which exceeded 10% of the benefit obligation at the beginning of the year in which they occurred. The amortization reflects the excess divided by the average remaining service period of active employees expected to receive benefits. Contributions from the Company are based on the funding amounts required by the Texas Commission in the Texas Rate Stipulation. The assets of the Other Postretirement Benefits Plan are invested in fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

The amounts recognized in the Company's balance sheets and the funded status of the plan at December 31, 2000 and 1999 are presented below (in thousands):

	December 31, 2000	December 31, 1999
Change in benefit obligation:		
Benefit obligation at beginning of year	$ (53,946)	$ (94,658)
Service cost	(2,289)	(2,226)
Interest cost	(4,357)	(3,994)
Actuarial gain (loss)	(8,727)(1)	45,314 (2)
Retirees' contributions	(230)	(215)
Benefits paid	1,803	1,833
Benefit obligation at end of year	(67,746)	(53,946)
Change in fair value of plan assets:		
Fair value of plan assets at beginning of year	13,525	11,254
Actual return (loss) on plan assets	(75)	467
Employer contribution	3,422	3,422
Retirees' contributions	230	215
Benefits paid	(1,803)	(1,833)
Fair value of plan assets at end of year	15,299	13,525
Funded status	(52,447)	(40,421)
Unrecognized net gain	(29,337)	(40,755)
Accrued benefit liability	$ (81,784)	$ (81,176)

(1) Represents a decrease in the discount rate.
(2) Represents a change in actuarial assumptions due to (i) a change in Medicare credits; (ii) revised census data; (iii) prior experience benefit; and (iv) an increase in the discount rate.

Net periodic benefit cost is made up of the components listed below (in thousands):

	Years Ended December 31, 2000	1999	1998
Components of net periodic benefit cost:			
Service cost	$ 2,289	$ 2,226	$ 2,818
Interest cost	4,357	3,994	5,822
Expected return on plan assets	(444)	(381)	(271)
Amortization of unrecognized gain	(2,171)	(1,719)	–
Net periodic benefit cost	$ 4,031	$ 4,120	$ 8,369

Weighted average assumptions are as follows:

	2000	1999	1998
Discount rate	7.25%	7.75%	6.75%
Expected return on plan assets	4.50%	4.50%	4.50%
Rate of compensation increase	5.00%	5.00%	5.00%

For measurement purposes, a 9.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001; the rate was assumed to decrease gradually to 6% for 2006 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 $8.5 million or $8.0 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of net periodic benefit cost by $1.2 million or $1.1 million, respectively.

All Employee Cash Bonus Plan

The All Employee Cash Bonus Plan (the "Bonus Plan"), introduced in early 1997, was established to reward employees for their contribution in helping the Company attain its corporate goals. Eligible employees below manager level would receive a cash bonus if the Company attained established levels of safety, customer satisfaction and financial results during 2000. The financial goal had to be met before any bonus amounts would be paid and the improvement in financial results had to be greater than any bonus amounts paid. The Company was able to attain its financial goal for 2000. As a result of the Company's success, the Company accrued approximately $4.9 million in cash bonuses, which were expensed in 2000 and were paid to all eligible employees in March 2001. The Company has renewed the Bonus Plan in 2001 with similar goals.

K. Franchises and Significant Customers

City of El Paso Franchise

The Company's major franchise is with the City of El Paso, Texas. The franchise agreement includes a 2% annual franchise fee (approximately $6.6 million per year currently) and provides an arrangement for the Company's utilization of public rights-of-way necessary to serve its retail customers within the City of El Paso. The franchise with the City of El Paso extends through August 1, 2005.

Las Cruces Franchise

The Company and Las Cruces entered into a seven-year franchise agreement with a 2% annual franchise fee (approximately $0.8 million per year currently) for the provision of electric distribution service in February 2000. 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 long-term 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 service from the Company through December 2008. The Company has a contract to provide retail electric service to Holloman for a ten-year term which began in December 1995. In May 1999, the Army and the Company entered into a new ten-year contract to provide retail electric service to White Sands.

L. Financial Instruments

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, long-term contract receivable, decommissioning trust funds, long-term debt and financing obligations, accounts payable, litigation settlement payable and customer deposits meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable, litigation settlement payable and customer deposits approximate fair value because of the short maturity of these items. Based on prevailing interest rates, the fair value of the long-term contract receivable approximates its carrying value. 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 at December 31, 2000 and 1999 and are presented below (in thousands):

	2000		1999	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
First Mortgage Bonds (1)	$ 556,128	$ 600,767	$ 594,976	$ 607,517
Pollution Control Bonds	193,135	194,350	193,135	193,135
Nuclear Fuel Financing(1)(2)	48,158	48,158	48,292	48,292
Total	$ 797,421	$ 843,275	$ 836,403	$ 848,944

(1) Includes current maturities.
(2) 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.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

M. Selected Quarterly Financial Data (Unaudited)

	2000 Quarters				1999 Quarters			
	4th(1)	3rd	2nd	1st	4th(2)	3rd	2nd	1st
	(In thousands except for share data)							
Operating revenues	$180,730	$211,410	$171,464	$138,045	$137,409	$170,340	$133,168	$129,552
Operating income	35,652	57,744	43,786	32,792	36,425	59,790	28,447	32,674
Income before extraordinary item	10,998	25,442	15,164	8,560	1,075	26,224	7,048	9,462
Extraordinary gain (loss) on extinguishments of debt, net of income tax (expense) benefit	–	(1,223)	4	(553)	(85)	(2,068)	(1,183)	–
Net income (loss) applicable to common stock	10,998	24,219	15,168	8,007	990	24,156	5,855	(2,725)
Basic earnings (loss) per common share:								
Income (loss) before extraordinary item	0.21	0.47	0.28	0.16	0.02	0.44	0.12	(0.05)
Extraordinary loss on extinguishments of debt, net of income tax benefit	–	(0.02)	–	(0.01)	–	(0.03)	(0.02)	–
Net income (loss)	0.21	0.45	0.28	0.15	0.02	0.41	0.10	(0.05)
Diluted earnings (loss) per common share:								
Income (loss) before extraordinary item	0.21	0.46	0.28	0.15	0.02	0.44	0.12	(0.05)
Extraordinary loss on extinguishments of debt, net of income tax benefit	–	(0.02)	–	(0.01)	–	(0.03)	(0.02)	–
Net income (loss)	0.21	0.44	0.28	0.14	0.02	0.41	0.10	(0.05)

(1) Includes an all employee bonus of approximately $3.1 million, net of income tax benefit, or $0.06 reduction in diluted earnings per common share.

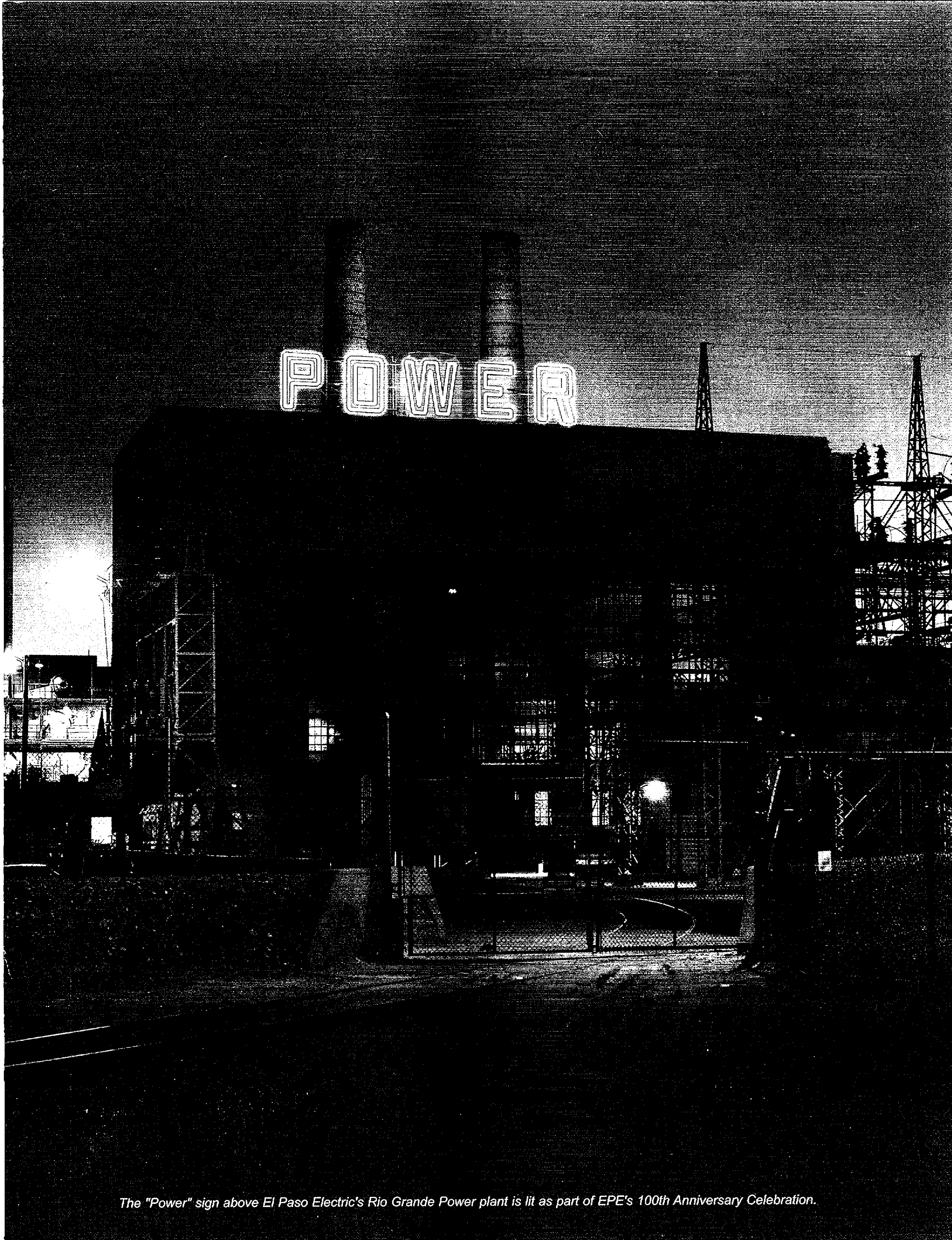
(2) Includes an accrued loss pursuant to the settlement agreement with Las Cruces, a coal mine reclamation adjustment, an all employee bonus, the write-off of capitalized interest on postload nuclear fuel and a sales tax liability adjustment, which resulted in an aggregate decrease in net earnings applicable to common stock of approximately $9.3 million, net of income tax benefit, or $0.16 reduction in diluted earnings per common share.

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

Not applicable.

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 "Power" sign above El Paso Electric's Rio Grande Power plant is lit as part of EPE's 100th Anniversary Celebration.

SOUTHERN CALIFORNIA EDISON COMPANY 2000 *Annual Report*

Southern California Edison Company (SCE) is one of the nation's largest investor-owned electric utilities. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International.

SCE, a 115-year-old electric utility, serves 4.3 million customers and more than 11 million people within a 50,000-square-mile area of central, coastal and Southern California.

Contents

Selected Financial and Operating Data: 1996-2000

Southern California Edison Company

Dollars in millions	**2000**	1999	1998	1997	1996
Income statement data:					
Operating revenue	**$ 7,870**	$ 7,548	$ 7,500	$ 7,953	$ 7,583
Operating expenses	**9,522**	6,693	6,582	6,893	6,450
Fuel and purchased power expenses	**4,882**	3,405	3,586	3,735	3,336
Income tax from operations	**(1,007)**	451	446	582	578
Allowance for funds used during construction	**21**	24	20	17	25
Interest expense — net of amounts capitalized	**572**	483	485	444	453
Net income (loss)	**(2,028)**	509	515	606	655
Net income (loss) available for common stock	**(2,050)**	484	490	576	621
Ratio of earnings to fixed charges	**(4.28)**	2.94	2.95	3.49	3.54
Balance sheet data:					
Assets	**$15,966**	$17,657	$16,947	$18,059	$17,737
Gross utility plant	**15,653**	14,852	14,150	21,483	21,134
Accumulated provision for depreciation and decommissioning	**7,834**	7,520	6,896	10,544	9,431
Common shareholder's equity	**780**	3,133	3,335	3,958	5,045
Preferred stock:					
Not subject to mandatory redemption	**129**	129	129	184	284
Subject to mandatory redemption	**256**	256	256	275	275
Long-term debt	**5,631**	5,137	5,447	6,145	4,779
Capital structure:					
Common shareholder's equity	**11.5%**	36.2%	36.4%	37.5%	48.6%
Preferred stock:					
Not subject to mandatory redemption	**1.9%**	1.5%	1.4%	1.7%	2.7%
Subject to mandatory redemption	**3.8%**	2.9%	2.8%	2.6%	2.7%
Long-term debt	**82.8%**	59.4%	59.4%	58.2%	46.0%
Operating data:					
Peak demand in megawatts (MW)	**19,757**	19,122	19,935	19,118	18,207
Generation capacity at peak (MW)	**10,191**	10,474	10,546	21,511	21,602
Kilowatt-hour sales (in millions)	**83,436**	78,602	76,595	77,234	75,572
Total energy requirement (kWh) (in millions)	**82,503**	78,752	80,289	86,849	84,236
Energy mix:					
Thermal	**36.0%**	35.5%	38.8%	44.6%	47.6%
Hydro	**5.4%**	5.6%	7.4%	6.5%	6.9%
Purchased power and other sources	**58.6%**	58.9%	53.8%	48.9%	45.5%
Customers (in millions)	**4.29**	4.36	4.27	4.25	4.22
Full-time employees	**12,593**	13,040	13,177	12,642	12,057

California's investor-owned electric utilities, including Southern California Edison Company (SCE), are currently facing a crisis resulting from deregulation of the generation side of the electric industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remain frozen at June 1996 levels. Since May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall has been accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. SCE has borrowed significant amounts of money to finance its electricity purchases, creating a severe financial drain on SCE.

On April 9, 2001, SCE and the California Department of Water Resources (CDWR) executed a memorandum of understanding (MOU) which sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which is expected to help restore SCE's creditworthiness and liquidity. The Governor of the State of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU is discussed in detail in the Memorandum of Understanding with the CDWR section. SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. If required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions by June 8, 2001, the MOU may be terminated by SCE or the CDWR. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken and definitive agreements executed before the applicable deadlines.

Accounting standards generally accepted in the United States permit SCE to defer costs as regulatory assets if those costs are determined to be probable of recovery in future rates. If SCE determines that regulatory assets, such as the TRA and the transition cost balancing account (TCBA), are no longer probable of recovery through future rates, they must be written off. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs, including stranded investments. SCE must assess the probability of recovery of the undercollected costs that are now recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceeding. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. Until legislative and regulatory actions contemplated by the MOU occur, or other actions are taken, SCE is unable to conclude that its undercollected costs that are recovered through the TCBA mechanism are probable of recovery in future rates. As a result, SCE's financial results for the year ended 2000 include an after-tax charge of approximately $2.5 billion ($4.2 billion on a pre-tax basis), reflecting a write-off of the TCBA (as restated to reflect the CPUC's March 27, 2001, decisions) and regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. In addition, SCE currently does not have regulatory authority to recover any purchased-power costs it incurs during 2001 in excess of revenue from retail rates. Those amounts will be charged against earnings in 2001 absent a regulatory or legislative solution, such as implementation of the actions called for in the MOU that makes recovery of such costs probable. This will result in further material declines in reported common shareholder's equity, particularly in light of the CPUC's failure to provide SCE with sufficient rate revenue to cover its ongoing costs and obligations through the CPUC's March 27, 2001, decisions. The December 31, 2000, write-off also caused SCE to be unable to meet an earnings test that must be met before SCE can issue additional first mortgage bonds. If the MOU is implemented, or a rate mechanism provided by legislation or regulatory authority is established that makes recovery from regulated rates probable as to all or a portion of the amounts that were previously charged against earnings, current accounting standards provide that a regulatory asset would be reinstated with a corresponding increase in earnings.

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the devastating effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and possible resolution of the current crisis through implementation of the MOU.

Results of Operations

Earnings

In 2000, SCE recorded a loss of $2.0 billion. The net loss in 2000 included a write-off of regulatory assets and liabilities in the amount of $2.5 billion (after tax) as of December 31, 2000. Accounting principles generally accepted in the United States require SCE at each financial statement date to assess the probability of recovering its regulatory assets through a regulatory process. On March 27, 2001, the CPUC issued a decision adopting a 3¢-per-kilowatt-hour (kWh) surcharge on rates effective immediately, with revenue generated by the surcharge to be applied to electric power costs incurred after the date of the order. This rate stabilization decision also stated that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called for TRA overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power Procurement Costs Recovery section of Regulatory Environment).

On April 9, 2001, SCE and the CDWR executed an MOU providing for the sale of SCE's transmission assets, or other assets under certain circumstances, recovery of SCE's net undercollected amount through the application of proceeds of the asset sale and one or more securitization financings, rate-making provisions for recovery of SCE's future power procurement costs, settlement of SCE's legal actions against the CPUC, and other elements of a comprehensive plan (see further discussion in Memorandum of Understanding with the CDWR). The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Until those actions or actions in other proceedings are taken, which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other regulatory assets and liabilities, that were to be recovered through the TCBA mechanism by the end of the rate freeze, are probable of recovery through the rate-making process as of December 31, 2000.

As a result, accounting principles generally accepted in the United States require that the net balance of these accounts be written off as a charge to earnings as of December 31, 2000. This write-off consists of the following:

In millions	
TCBA (as recalculated)	$2,878
Unamortized nuclear investment — net	610
Purchased-power settlements	435
Unamortized loss on sale of plant	61
Other regulatory assets — net	39
Subtotal	4,023
Flow-through taxes	218
Total regulatory assets — net	4,241
Less income tax benefit	(1,720)
Net write-off	$2,521

This write-off is included in the income statement as a $4.0 billion charge to provisions for regulatory adjustment clauses, and a $1.5 billion net reduction in income tax expense.

As stated above, an MOU has been negotiated with representatives of the Governor (see Memorandum of Understanding with the CDWR) to resolve the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions or other actions that make such recovery probable are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Excluding the write-off, SCE's 2000 earnings were $471 million. SCE's earnings were $484 million in 1999 and $490 million in 1998. SCE's 1999 earnings include a $15 million one-time tax benefit due to an Internal Revenue Service ruling. The 2000 decrease was mainly due to adjustments to reflect potential regulatory refunds and lower gains from sales of equity investments, partially offset by superior operating performance at the San Onofre Nuclear Generating Station and higher kWh sales. Excluding the one-time tax benefit, SCE's 1999 earnings were $469 million, down $21 million from 1998. The 1999 decrease was primarily due to the accelerated depreciation of SCE's generation assets, partially offset by higher kWh sales in 1999.

Unless a rate-making mechanism is implemented in accordance with the MOU described above or other necessary rate-making action is taken, future net undercollections in the TCBA will be charged to earnings as the losses are incurred. The loss (before tax) incurred in this balancing account (as redefined) in January and February 2001 amounts to approximately $800 million. SCE anticipates that losses will continue unless a rate-making mechanism is established. In addition to the losses from the TCBA undercollections, SCE expects its 2001 earnings to be negatively affected by the recent fire and resulting damage at San Onofre Unit 3. See further discussion of the San Onofre fire in the San Onofre Nuclear Generating Station section.

Operating Revenue

SCE's customers are able to choose to purchase power directly from an energy service provider, thus becoming direct access customers, or continue to have SCE purchase power on their behalf. Most direct access customers are billed by SCE, but given a credit for the generation portion of their bills. Under Assembly Bill 1 (First Extraordinary Session) (AB 1X), enacted on February 1, 2001, the CPUC was directed (on a schedule it determines) to suspend the ability of retail customers to select alternative providers of electricity until the CDWR stops buying power for retail customers.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for a lower generation rate with a provision that service can be interrupted if needed, with penalties for noncompliance) were asked to curtail their electricity usage at various times. As a result of noncompliance with SCE's requests, those customers were assessed significant penalties.

On January 26, 2001, the CPUC waived the penalties being assessed to noncompliant customers until a reevaluation of the operation of the interruptible programs can be completed.

Operating revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not adhering to their interruptible contracts. The increase in resale sales resulted from other utilities and municipalities exercising their contractual option to buy more power from SCE as the price of power purchased through the California Power Exchange (PX) and Independent System Operator (ISO) increased significantly in 2000. These increases were partially offset by the credit given to customers who chose direct access. Operating revenue increased by less than 1% in 1999, as increased kWh sales and revenue resulting from maintenance work SCE was providing the new owners of generating plants previously sold by SCE was almost completely offset by the credit given to customers who chose direct access. On March 27, 2001, the CPUC affirmed that the interim surcharge of 1¢ per kWh granted on January 4, 2001, is now permanent. See further discussion in Rate Stabilization Proceeding.

In 2000, more than 92% of operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, operating revenue during the third quarter of each year is significantly higher than other quarters.

The changes in operating revenue resulted from:

In millions Year ended December 31,	**2000**	1999	1998
Operating revenue —			
Rate changes (including refunds)	**$ 120**	$ (75)	$ (498)
Direct access credit	**(434)**	(213)	(29)
Interruptible noncompliance penalty	**102**	6	—
Sales volume changes	**520**	195	(44)
Other	**14**	136	117
Total	**$ 322**	$ 49	$ (454)

Operating Expenses

Fuel expense decreased in both 2000 and 1999. The decrease in 2000 was primarily due to fuel-related refunds resulting from a settlement with another utility that SCE recorded in the second and third quarters of 2000. The decrease in 1999 was due to the sale of 12 generating plants in 1998.

Prior to April 1998, SCE was required under federal law and CPUC orders to enter into contracts to purchase power from qualifying facilities (QFs) at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. Purchased-power expense related to contracts decreased in both 2000 and 1999. The decrease in 2000 was primarily due to a contract adjustment with a state agency, as well as the terms in some of the remaining QF contracts reverting to lower prices. The decrease in 1999 was primarily due to the terms in some of the remaining QF contracts reverting to lower prices, as well as SCE's settlement agreements to terminate contracts with certain QFs. SCE's settlement agreements with certain QFs decreased purchased-power expense related to contracts by $47 million in 1999. SCE's purchased-power settlement obligations were recorded as a liability. Because the settlement payments were to be recovered through the TCBA mechanism as the payments were made, a regulatory asset was also recorded. As of December 31, 2000, the purchased-power settlement regulatory asset was written off as a charge to earnings. See further discussion of the write-off in Earnings.

In 2000, PX/ISO purchased-power expense increased significantly due to increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and structural problems within the PX and ISO. The increased volume of higher priced PX purchases was minimally offset by increases in PX sales revenue and ISO net revenue, as well as the use of risk management instruments (gas call options and PX block forward contracts). The gas call options (which were sold in October 2000) and the PX block forward contracts mitigated SCE's transition cost recovery exposure to increases in energy prices. SCE's use of gas call options reduced PX/ISO purchased-power expense by $200 million in 2000 compared to 1999. SCE's use of PX block forward contracts reduced PX/ISO purchased-power expense by $688 million in 2000 compared to 1999. In 1999, PX/ISO purchased-power expense increased compared to 1998, mainly due to three additional months of PX transactions in 1999. However, when 1999 PX purchased-power expense was compared on the same nine-month basis as 1998, the increase was less than 1%, despite the fact that SCE experienced a significant decrease in the volume of kWh sales through the PX. The lower volume of sales through the PX in 1999 was the result of less generation at SCE (due to San Onofre refueling outages in 1999, divestiture of 12 generating plants in 1998 and reduced hydroelectric generation) and fewer purchases from QFs. SCE's use of gas call options decreased PX/ISO purchased-power expense by $8 million in 1999 compared to 1998. SCE's use of PX block forward contracts increased PX/ISO purchased-power expense by $3 million in 1999 compared to 1998. For a further discussion of SCE's hedging instruments and the recent significant increases in power prices, see Market Risk Exposures. As of December 15, 2000, the FERC eliminated the requirement that SCE buy and sell its purchased and generated power through the PX and ISO. See further discussion in Wholesale Electricity Markets.

Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges for the day-of market effective January 18, 2001, and, for the day-ahead market effective January 19, 2001. See further discussion of SCE's liquidity crisis in Financial Condition.

Provisions for regulatory adjustment clauses increased in 2000 and decreased in 1999. The 2000 increase was mainly due to a write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. See further discussion of the write-off in the Earnings section. In addition, the provision also increased in 2000 due to adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs. The decrease in 1999 was mainly due to undercollections related to the TCBA and the rate-making treatment of the rate reduction notes. These undercollections were partially offset by overcollections related to the administration of public purpose funds. The rate-making treatment associated with rate reduction notes has allowed for the deferral of the recovery of a portion of the transition-related costs, from a four-year period to a 10-year period. SCE's use of gas call options increased the provisions by $200 million in 2000 compared to 1999, and decreased the provisions by $8 million in 1999 compared to 1998.

Other operation and maintenance expense decreased in 2000, primarily due to a $120 million decrease in mandated transmission service (known as must-run reliability services) expense and a $19 million decrease in operating expenses at San Onofre. The decrease at San Onofre in 2000 was primarily due to scheduled refueling outages for both units in the first half of 1999. San Onofre had only one refueling outage in 2000. Other operation and maintenance expense increased in 1999, mostly due to an increase in mandated transmission service expense and PX and ISO costs incurred by SCE. These increases were partially offset by lower expenses incurred for distribution facilities.

Income taxes decreased in 2000, primarily due to the $1.5 billion income tax benefit related to the write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent the write-off, SCE's income tax expense increased in 2000 due to higher pre-tax income.

Net gain on sale of utility plant in 2000 resulted from the sale of additional property related to four of the generating stations SCE sold in 1998. The gains were returned to the ratepayers through the TCBA mechanism.

Other Income and Deductions

Interest and dividend income increased in 2000, primarily due to increases in interest earned on higher balancing account undercollections.

Other nonoperating income decreased in 2000 but increased in 1999. Although SCE recorded gains on sales of equity investments in 2000, 1999 and 1998, the different amounts of the gains were the primary reason for other nonoperating income to decrease in 2000 when compared to 1999, and to increase in 1999 when compared to 1998.

Interest expense — net of amounts capitalized increased in 2000 and decreased slightly in 1999. The increase in 2000 was mostly due to higher overall short-term debt balances necessary to meet general cash requirements (especially PX and ISO payments) and higher interest expense related to balancing account overcollections. The decrease in 1999 was mainly due to a decrease in interest on long-term debt more than offsetting an increase resulting from higher overall short-term debt balances necessary to meet general cash requirements and higher interest expense related to balancing account overcollections. The 1999 decrease in interest on long-term debt was due to an adjustment of accrued interest in first quarter 1998 related to the rate reduction notes issued in December 1997.

Other nonoperating deductions decreased in 1999, as expenses related to a ballot initiative in 1998 more than offset additional accruals for regulatory matters in 1999.

The tax benefit on other income and deductions increased in both 2000 and 1999. The increase in 2000 was primarily the result of tax benefits related to interest expense and other nonoperating expenses exceeding the tax expense related to interest income and other nonoperating income. The increase in 1999 was primarily the result of a $15 million one-time tax benefit due to an Internal Revenue Service ruling.

Financial Condition

SCE's liquidity is primarily affected by power purchases, debt maturities, access to capital markets, dividend payments and capital expenditures. Capital resources include cash from operations and external financings. As a result of SCE's lack of creditworthiness (further discussed in Liquidity Crisis), at March 31, 2001, the fair market value of approximately $500 million of its short-term debt was approximately 75% of its carrying value (as compared to 100% at December 31, 2000) and the fair market value of its long-term debt was approximately 90% of its carrying value (as compared to 92% at December 31, 2000).

Beginning in 1995, Edison International's Board of Directors authorized the repurchase of up to $2.8 billion of its outstanding shares of common stock. Edison International repurchased more than 21 million shares (approximately $400 million) of its common stock during the first six months of 2000. These were the first repurchases since first quarter 1999. Between January 1, 1995, and June 30, 2000, Edison International repurchased $2.8 billion (approximately 122 million shares) of its outstanding shares of common stock, funded by dividends from its subsidiaries (primarily from SCE).

Liquidity Crisis

Sustained higher wholesale energy prices that began in May 2000 persisted through Spring 2001. This resulted in an increasing undercollection in the TRA. The increasing undercollection, coupled with SCE's anticipated near-term capital requirements (detailed in the Projected Capital Requirements section of Financial Condition) and the adverse reaction of the credit markets to continued regulatory uncertainty adversely affected SCE's liquidity. As a result of its liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or ISO; (2) $1.1 billion to QFs; (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5-7/8% notes; and (6) $7 million of other obligations. SCE's failure to pay when due the principal amount of the 5-7/8% series of notes constitutes a default on the series, entitling those noteholders to exercise their remedies. Such failure and the failure to pay commercial paper when due could also constitute an event of default on all the other series of notes (totaling $2.4 billion of outstanding principal) if the trustee or holders of 25% in principal amount of the notes give a notice demanding that the default be cured, and SCE does not cure the default within 30 days. Such failures are also an event of default under SCE's credit facilities, entitling those lenders to exercise their remedies including potential acceleration of the outstanding borrowings of $1.6 billion. If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5-7/8% notes. Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders were to declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

Subject to certain conditions, the bank lenders under SCE's credit facilities agreed to forbear from exercising remedies, including acceleration of borrowed amounts, against SCE with respect to the event of default arising from the failure to pay the 5-7/8 notes and commercial paper when due. The initial forbearance agreement expired on February 13, 2001, but it has been extended twice and currently expires on April 28, 2001. At March 31, 2001, SCE had estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations (discussed above) and overdue amounts of preferred stock dividends (see below). As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness, which would allow SCE to pay all of its past due obligations.

On March 27, 2001, the CPUC ordered SCE and the other California investor-owned utilities to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay the QFs within 15 days of the end of the QFs' billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a required payment within 15 days of delivery would result in a fine equal to the amount owed to the QF. The CPUC decision also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than index prices at the Arizona border. The changes apply to all QFs, where appropriate, regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation (see CDWR Power Purchases discussion) and the approval of a 3¢per-kWh rate increase (see Rate Stabilization Proceeding discussion). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the CDWR, and the QF decision discussed above could result in a shortfall to the CPA calculation of $1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to SCE's parent, Edison International, in either December 2000 or March 2001. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. As of March 31, 2001, SCE's preferred stock dividends in arrears were $6 million. As a result of SCE's $2.5

declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. As of March 31, 2001, SCE's preferred stock dividends in arrears were $6 million. As a result of SCE's $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. These actions were expected to impact about 1,450 to 1,850 jobs, affect service levels for customers, and reduce near-term capital expenditures to levels that will not sustain operations in the long term. However, on March 15, 2001, the CPUC issued an order rescinding SCE's layoffs of employees involved with service and reliability. SCE was also ordered to restore specified service levels, make regular reports to the CPUC concerning its cost-cutting measures, and track its cost savings pending future adjustments to rates. The amount of the cost savings affected by the order is not material. SCE's current actions, including the suspension of debt and purchased-power obligations, are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future. See further discussion in Status of Transition and Power Procurement Costs Recovery.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on an agreement to resolve SCE's crisis, see Memorandum of Understanding with the CDWR.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain. In addition, SCE's independent accountant's opinion in the accompanying financial statements includes an explanatory paragraph which states that the issues resulting from the California energy crisis raise substantial doubt about SCE's ability to continue as a going concern.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $829 million in 2000, $1.5 billion in 1999 and $978 million in 1998. The decrease in cash flows provided by operating activities in 2000 was primarily due to the extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO. Cash flows provided by operations is expected to increase in the first half of 2001 as SCE conserves cash as result of the liquidity crisis (see Liquidity Crisis discussion).

SCE's cash flow coverage of dividends was 2.1 times for both 2000 and 1999, and 0.9 times for 1998. The 1999 increase primarily reflects the rate-making treatment of the gains on sales of the generating plants, as well as the special dividend ($680 million) SCE paid to Edison International in 1998. Beginning in first quarter 2001, the cash flow coverage of dividends calculation will reflect SCE's inability to pay dividends (discussed above in the Liquidity Crisis section).

SCE's estimates of cash available for operations in 2001 assume, among other things, satisfactory reimbursement of costs incurred during California's energy crisis, the receipt of adequate and timely rate relief, and the realization of its assumptions regarding cost increases, including the cost of capital.

Cash Flows from Financing Activities

At December 31, 2000, SCE had total credit lines of $1.65 billion, with $125 million available for the refinancing of its variable-rate pollution-control bonds. These unsecured lines of credit have various expiration dates and can be drawn down at negotiated or bank index rates. However, as of January 2, 2001, SCE had drawn on its entire credit lines of $1.65 billion.

Short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings, SCE does not currently meet the interest coverage ratios that are required for SCE to issue additional first mortgage bonds or preferred stock. In addition, because of its current liquidity and credit problems, SCE is unable to obtain financing of any kind.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, SCE has been unable to sell its commercial paper and other short-term financial instruments.

In January 2001, Fitch IBCA, Standard & Poor's and Moody's Investors Service lowered their credit ratings of SCE to substantially below investment grade. In mid-April, Moody's removed SCE's credit ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other agencies.

Subject to the outcome of regulatory, legislative and judicial proceedings, including steps to implement the MOU, SCE intends to pay all of its obligations.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities beginning in 2001 and ending in 2007, with interest rates ranging from 6.17% to 6.42%. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International. Due to its recent credit rating downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, non-dollar, and cash equivalent securities; and derivatives of all descriptions are prohibited. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a review proceeding will provide input into the contribution analysis for that proceeding's contribution determination.

Projected Capital Requirements

SCE's projected construction expenditures for 2001 are $602 million. This projection reflects SCE's recently announced cost-cutting measures discussed above in the Liquidity Crisis section.

Long-term debt maturities and sinking fund requirements for the next five years are: 2001 – $646 million; 2002 – $746 million; 2003 – $1.4 billion; 2004 – $371 million; and 2005 – $246 million.

Preferred stock redemption requirements for the next five years are: 2001– zero; 2002 – $105 million; 2003 – $9 million; 2004 – $9 million; and 2005 – $9 million.

Market Risk Exposures

SCE's primary market risk exposures arise from fluctuations in both energy prices and interest rates. SCE's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes. At December 31, 2000, a 10% change in market rates would have had an immaterial effect on SCE's financial instruments not specifically discussed below.

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes and to fund business operations, as well as to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. As a result of California's energy crisis, SCE has been exposed to significantly higher interest rates, which has intensified its liquidity crisis (further discussed in the Liquidity Crisis section of Financial Condition).

At December 31, 2000, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $222 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $244 million increase in the fair market value of SCE's long-term debt. See further discussion in Financial Condition of the impact of SCE's lack of creditworthiness on its short-term and long-term debt.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $5 million increase in the fair value of SCE's interest rate swap. A 10% decrease in market interest rates would have resulted in an $8 million decrease in the fair value of SCE's interest rate swap. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on

January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, since May 2000, market power prices have skyrocketed, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power, but these caps are set at high levels and are not entirely effective. For example, SCE paid an average of $248 per megawatt in December 2000, versus an average of $32 per megawatt in December 1999.

SCE attempted to hedge a portion of its exposure to increases in power prices. However, the CPUC has approved a very limited amount of hedging. In 1997, SCE bought gas call options as a hedge against electricity price increases, since gas is a primary component for much of SCE's power supply. These gas call options were sold in October 2000, resulting in a $190 million gain (lowering purchased-power expense) for 2000. In July 1999, SCE began forward purchases of electricity through the PX block forward market. In November 2000, SCE began purchases of energy through bilateral forward contracts. At December 31, 2000, the nominal value of SCE's block and bilateral forward contracts was $234 million and $798 million, respectively. The block forward contracts reduced purchased-power costs by $684 million in 2000.

At December 31, 2000, a 10% fluctuation in electricity prices would have changed the fair market value of SCE's forward contracts by $187 million.

Because SCE has temporarily suspended payments for purchased power since January 16, 2001, the PX sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the State of California seized the contracts, but must pay SCE the reasonable value of the contracts under the law. A valuation of the contracts is expected in mid-2001. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts.

Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

In January 2001, the CDWR began purchasing power for delivery to utility customers. On March 27, 2001, the CPUC issued a decision directing SCE to, among other things, immediately pay amounts owed to the CDWR for certain past purchases of power for SCE's customers. See additional discussion of regulatory proceedings related to CDWR activities in the Generation and Power Procurement section of Regulatory Environment.

Regulatory Environment

SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory and certain obligations of the regulatory authorities to provide just and reasonable rates. In 1996, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own those generating plants. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms (as described in Status of Transition and Power Procurement Costs Recovery) allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates were to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations were recovered. However, since May 2000, the prices charged by sellers of power have escalated far beyond what SCE can currently charge its customers. See further discussion in Wholesale Electricity Markets.

Generation and Power Procurement

During the rate freeze, revenue from generation-related operations has been determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. The portion of revenue related to coal generation plant costs (Mohave Generating Station and Four Corners Generating Station) that was made uneconomic by electric industry restructuring has been recovered through the transition cost recovery mechanisms. After April 1, 1998, coal generation operating costs have been recovered through the market. The excess of power sales revenue from the coal generating plants over the plants' operating costs has been accumulated in a coal generation balancing account. SCE's costs associated with its hydroelectric plants have been recovered through a performance-based mechanism. The mechanism set the hydroelectric revenue requirement and established a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurred first. The mechanism provided that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement is accumulated in a hydroelectric balancing account. In accordance with a CPUC decision issued in 1997, the credit balances in the coal and hydroelectric balancing accounts were transferred to the TCBA at the end of 1998 and 1999. However, due to the CPUC's March 27, 2001, rate stabilization decision, the credit balances in these balancing accounts have now been transferred to the TRA on a monthly basis, retroactive to January 1, 1998. In addition, the TRA balance, whether over- or undercollected, has now been transferred to the TCBA on a monthly basis, retroactive to January 1, 1998. Due to a December 15, 2000, FERC order, SCE is no longer required to buy and sell power exclusively through the ISO and PX. In mid-January 2001, the PX suspended SCE's trading privileges for failure to post collateral due to SCE's rating agency downgrades. As a result, power from SCE's coal and hydroelectric plants is no longer being sold through the market and these two balancing accounts have become inactive. As a key element of the MOU, SCE would continue to own its generation assets, which would be subject to cost-based ratemaking, through 2010. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

SCE has been recovering its investment in its nuclear facilities on an accelerated basis in exchange for a lower authorized rate of return on investment. SCE's nuclear assets are earning an annual rate of return on investment of 7.35%. In addition, the San Onofre incentive pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre plan commenced in April 1996, and ends at the earlier of December 2001 or the date when the statutory rate freeze ends for the accelerated recovery portion, and in December 2003 for the incentive-pricing portion. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, are subject to balancing account treatment. The Palo Verde plan commenced in January 1997 and ends in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period. Under the MOU, both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), SCE is no longer able to conclude that the unamortized nuclear investment regulatory assets (as discussed in Accounting for Generation-Related Assets and Power Procurement Costs) are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfalls from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the State if a sale of SCE's transmission assets is not completed under certain circumstances. In June 2000, SCE credited the TCBA with the estimated excess of market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric assets. If there were a difference in the final market value, it would have been credited to or recovered from customers through the TCBA. Due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), the GABA transaction was reclassified back to the TCBA, and as discussed in the Earnings section, the TCBA balance (as recalculated based on a March 27, 2001, CPUC interim decision discussed in Rate Stabilization Proceeding) was written off as of December 31, 2000.

During 2000, SCE entered into agreements to sell the Mohave, Palo Verde and Four Corners generation stations. The sales were pending various regulatory approvals. Due to the shortage of electricity in California and the increasing wholesale costs, state legislation was enacted in January 2001 barring the sale of utility generation stations until 2006. Under the MOU, SCE would continue to retain its generation assets through 2010.

<u>CDWR Power Purchases</u>

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, AB 1X was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of a CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢-per-kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain non-generation related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh. The CPUC determined that the company-wide generation-related rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢-surcharge discussed in Rate Stabilization Proceeding), for each kWh delivered to customers beginning February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers. Using these rates, SCE has billed customers $196 million for energy sales made by the CDWR during the period

January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Liquidity Crisis) and the payments ordered to be made to CDWR (discussed above), could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU described in Memorandum of Understanding with CDWR, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it can not assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transactions. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Status of Transition and Power Procurement Costs Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions (discussed in Rate Stabilization Proceeding). Until the various regulatory and legislative actions necessary to implement the MOU, or other actions that make such recovery probable are taken, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets, and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 bars the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets (see discussion in Generation and Power Procurement) are no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover non-transition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue (TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceeding).

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9

billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$3,561
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	577
Other transition costs	634
Total transition costs	7,862
Revenue available to recover transition costs	(4,984)
Unrecovered transition costs	$2,878

Unless the regulatory and legislative actions required to implement the MOU, or other actions that make such recovery probable are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings). In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002. For more details on the matters discussed above, see Rate Stabilization Proceeding.

Litigation

In November 2000, SCE filed a lawsuit against the CPUC in federal court in California, seeking a ruling that SCE is entitled to full recovery of its past electricity procurement costs in accordance with the tariffs filed with the FERC. The effect of such a ruling would be to overturn the prior decisions of the CPUC restricting recovery of TRA undercollections. In January 2001, the court denied the CPUC's motion to dismiss the action and also denied SCE's motion for summary judgment without prejudice. In February 2001, the court denied SCE's motion for a preliminary injunction ordering the CPUC to institute rates sufficient to enable SCE to recover its past procurement costs, subject to refund. The court granted, in part, SCE's additional motion to specify certain material facts without substantial controversy, but denied the remainder of the motion and declined to declare at that time that SCE is entitled to recover the amount of its undercollected procurement costs. In March 2001, the court directed the parties to be prepared for trial on July 31, 2001. As discussed in the Memorandum of Understanding with the CDWR, after the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government. SCE cannot predict whether or when a favorable final judgment or other resolution would be obtained in this legal action, if it were to proceed to trial.

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with the March 15, 2001, lawsuit discussed below. SCE believes that its current and past accounting for the TRA undercollections and related items, as described above, is appropriate and in accordance with accounting principles generally accepted in the United States.

On March 15, 2001, a purported class action lawsuit was filed in federal district court in Los Angeles against Edison International and SCE and certain of their officers. The complaint alleges that the defendants engaged in securities fraud by misrepresenting and/or failing to disclose material facts concerning the financial condition of Edison International and SCE, including that the defendants allegedly over-reported income and improperly accounted for the TRA undercollections. The complaint is supposedly filed on behalf of a class of persons who purchased all publicly traded securities of Edison International between May 12, 2000, and December 22, 2000. Pursuant to an agreement with Edison International and SCE, this lawsuit is expected to be consolidated with the October 20, 2000, lawsuit discussed above, pending the court's approval.

In addition to the two lawsuits filed against SCE and discussed above, as of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund (see additional discussion below). The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens past CPUC decisions authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. SCE cannot provide assurance that the CPUC will adopt such a decision, or predict what effects any investigation or any subsequent actions by the CPUC may have on SCE.

In its interim rate stabilization order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢-per-kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢-increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢-surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision (see CDWR Power Purchases).

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA, whether over- or undercollected, be transferred on a monthly basis to the TCBA, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis (see further discussion of the recalculation of the TCBA in Status of Transition and Power Procurement Costs Recovery). SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thus only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it would monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceeding. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Accounting for Generation-Related Assets and Power Procurement Costs

In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets. At that time, SCE did not write off any of its generation-related assets, including related regulatory assets, because the electric utility industry restructuring plan made probable their recovery through a nonbypassable charge to distribution customers.

During the second quarter of 1998, in accordance with asset impairment accounting standards, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Unless those actions or other actions that make such recovery probable are taken, which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its generation-related regulatory assets and liabilities to be amortized into the TCBA, are probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States require that the balances in the accounts be written off as a charge to earnings as of December 31, 2000 (see Earnings).

As discussed below, an MOU has been negotiated with representatives of the Governor as a step to resolving the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions, or other actions that make such recovery probable, are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Memorandum of Understanding with the CDWR

On April 9, 2001, SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.

- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.

- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment grade credit rating.

- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- An affiliate of Edison International will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for 10 years from a power project currently under development. The Edison International affiliate will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.

- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.

- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. The distribution PBR will extend through December 2001. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety;

and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations.

Transmission

Transmission revenue is determined through FERC-authorized rates and is subject to refund.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive; immediately impose a cap on the price for energy and ancillary services; and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. Three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, the FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to the FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over the sellers' exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above

$430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

As further discussed in Note 12 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. SCE believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $75 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information. As a result, no reasonable estimate of cleanup costs can be made for these sites. SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $5 million to $15 million. Recorded costs for 2000 were $13 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In 1998, several environmental groups filed suit against the co-owners of the Mohave station regarding alleged violations of emissions limits. In order to accelerate resolution of key environmental issues regarding the plant, the parties filed, in concurrence with SCE and the other station owners, a consent decree, which was approved by the court in December 1999. In a letter to SCE, the EPA has expressed its belief that the controls provided in the consent decree will likely resolve the potential Clean Air Act visibility concerns. The EPA is considering incorporating the decree into the visibility provisions of its Federal Implementation Plan for Nevada.

SCE's projected environmental capital expenditures are $1.2 billion for the 2001-2005 period, mainly for undergrounding certain transmission and distribution lines.

San Onofre Nuclear Generating Station

On February 3, 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. SCE expects that Unit 3 will return to service sometime in mid-June 2001. SCE anticipates that its lost revenue under the currently effective San Onofre rate-recovery plan (discussed in the Generation and Power Procurement section of Regulatory Environment) will be approximately $100 million.

The San Onofre Units 2 and 3 steam generators' design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. Increased tube degradation was found during routine inspections in 1997. To date, 8% of Unit 2's tubes and 6% of Unit 3's tubes have been removed from service. A decreasing (favorable) trend in degradation has been observed in more recent inspections.

Accounting Changes

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. On the implementation date, SCE recorded its interest rate swap agreement (terminated January 5, 2001), and its block forward power purchase contracts (seized by the State of California on February 2, 2001) at fair value on its balance sheet. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates.

Forward-looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as implementation (or non-implementation) of the MOU as described above; the outcome of negotiations for solutions to SCE's liquidity problems; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry; actions by lenders, investors and creditors in response to SCE's suspension of payments for debt service and purchased power, including the possible filing of an involuntary bankruptcy petition against SCE; the effects, unfavorable interpretations and applications of new or existing laws and regulations relating to restructuring, taxes and other matters; the effects of increased competition in energy-related businesses; changes in prices of electricity and fuel costs; the actions of securities rating agencies; the availability of credit, including SCE's ability to regain an investment grade credit rating and re-enter the credit markets; changes in financial market conditions; the amount of revenue available to both transition and non-transition costs; new or increased environmental liabilities; the financial viability of new businesses, such as telecommunications; weather conditions; and other unforeseen events.

Consolidated Statements of Income (Loss)

Southern California Edison Company

In thousands Year ended December 31,	2000	1999	1998
Operating revenue	**$ 7,869,950**	$ 7,547,834	$ 7,499,519
Fuel	**194,961**	214,972	323,716
Purchased power — contracts	**2,357,336**	2,419,147	2,625,900
Purchased power — PX/ISO — net	**2,329,276**	770,574	636,343
Provisions for regulatory adjustment clauses — net	**2,301,268**	(762,653)	(472,519)
Other operation and maintenance	**1,771,792**	1,933,217	1,891,210
Depreciation, decommissioning and amortization	**1,472,872**	1,547,738	1,545,735
Income taxes	**(1,006,825)**	451,247	445,642
Property and other taxes	**125,720**	121,628	128,402
Net gain on sale of utility plant	**(24,602)**	(3,035)	(542,608)
Total operating expenses	**9,521,798**	6,692,835	6,581,821
Operating income (loss)	**(1,651,848)**	854,999	917,698
Interest and dividend income	**172,736**	69,389	66,725
Other nonoperating income	**118,064**	162,317	129,046
Interest expense — net of amounts capitalized	**(571,760)**	(483,241)	(484,788)
Other nonoperating deductions	**(110,163)**	(107,285)	(116,845)
Taxes on other income and deductions	**14,627**	13,242	3,286
Net income (loss)	**(2,028,344)**	509,421	515,122
Dividends on preferred stock	**21,443**	25,889	24,632
Net income (loss) available for common stock	**$ (2,049,787)**	$ 483,532	$ 490,490

Consolidated Statements of Comprehensive Income (Loss)

In thousands Year ended December 31,	2000	1999	1998
Net income (loss)	**$ (2,028,344)**	$ 509,421	$ 515,122
Unrealized gain on securities – net	**2,919**	28,009	9,275
Reclassification adjustment for gains included in net income	**(24,470)**	(45,920)	(17,836)
Comprehensive income (loss)	**$ (2,049,895)**	$ 491,510	$ 506,561

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheets

In thousands December 31,	2000	1999
ASSETS		
Utility plant, at original cost:		
Transmission and distribution	**$13,128,755**	$12,439,059
Generation	**1,745,505**	1,717,676
Accumulated provision for depreciation and decommissioning	**(7,834,201)**	(7,520,036)
Construction work in progress	**635,572**	562,651
Nuclear fuel, at amortized cost	**143,082**	132,197
Total utility plant	**7,818,713**	7,331,547
Nonutility property — less accumulated provision for depreciation of $11,008 and $6,797 at respective dates	**102,223**	103,644
Nuclear decommissioning trusts	**2,504,990**	2,508,904
Other investments	**89,570**	160,241
Total investments and other assets	**2,696,783**	2,772,789
Cash and equivalents	**583,159**	26,046
Receivables, less allowances of $23,220 and $24,665 for uncollectible accounts at respective dates	**919,045**	579,859
Accrued unbilled revenue	**376,873**	433,802
Fuel inventory	**11,720**	49,989
Materials and supplies, at average cost	**131,651**	122,866
Accumulated deferred income taxes — net	**544,561**	188,143
Prepayments and other current assets	**124,736**	111,151
Total current assets	**2,691,745**	1,511,856
Regulatory assets — net	**2,390,124**	5,555,216
Other deferred charges	**368,731**	485,898
Total deferred charges	**2,758,855**	6,041,114
Total assets	**$15,966,096**	$17,657,306

The accompanying notes are an integral part of these financial statements.

In thousands, except share amounts December 31,	Southern California Edison Company 2000	1999
CAPITALIZATION AND LIABILITIES		
Common shareholder's equity:		
Common stock (434,888,104 shares outstanding at each date)	**$2,168,054**	$ 2,168,054
Additional paid-in capital	**334,030**	335,038
Accumulated other comprehensive income	**—**	21,551
Retained earnings (deficit)	**(1,721,599)**	608,453
	780,485	3,133,096
Preferred stock:		
Not subject to mandatory redemption	**128,755**	128,755
Subject to mandatory redemption	**255,700**	255,700
Long-term debt	**5,631,308**	5,136,681
Total capitalization	**6,796,248**	8,654,232
Short-term debt	**1,451,071**	795,988
Current portion of long-term debt	**646,300**	571,300
Accounts payable	**1,055,483**	573,919
Accrued taxes	**535,517**	500,709
Accrued interest	**96,053**	82,554
Dividends payable	**662**	94,407
Regulatory liabilities — net	**195,047**	100,907
Deferred unbilled revenue	**249,949**	300,339
Other current liabilities	**1,154,834**	1,114,834
Total current liabilities	**5,384,916**	4,134,957
Accumulated deferred income taxes — net	**2,009,290**	2,938,661
Accumulated deferred investment tax credits	**163,952**	205,197
Customer advances and other deferred credits	**754,741**	823,992
Power purchase contracts	**466,231**	563,459
Accumulated provision for pensions and benefits	**296,380**	233,003
Other long-term liabilities	**93,978**	103,470
Total deferred credits and other liabilities	**3,784,572**	4,867,782
Minority interest	**360**	335
Commitments and contingencies (Notes 2, 3, 11 and 12)		
Total capitalization and liabilities	**$15,966,096**	$17,657,306

The accompanying notes are an integral part of these financial statements.

Consolidated Statements of Cash Flows

In thousands Year ended December 31,	2000	1999	1998
Cash flows from operating activities:			
Net income (loss)	**$(2,028,344)**	$ 509,421	$ 515,122
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,472,872**	1,547,738	1,545,735
Other amortization	**96,958**	95,060	89,323
Deferred income taxes and investment tax credits	**(927,607)**	177,599	(94,504)
Regulatory balancing accounts — long-term	**1,758,594**	(1,353,570)	(361,403)
Regulatory asset related to the sale of generating plants	**48**	179	(220,232)
Net gain on sale of generating plants	**(14,287)**	(938)	(564,623)
Net gain on sale of marketable securities	**(41,161)**	(77,241)	(30,002)
Other assets	**44,369**	(62,328)	(45,191)
Other liabilities	**850**	17,315	40,263
Changes in working capital:			
Receivables	**(282,257)**	98,969	(206,242)
Regulatory balancing accounts — short-term	**96,882**	363,071	(94,067)
Fuel inventory, materials and supplies	**29,484**	(5,297)	23,481
Prepayments and other current assets	**(13,585)**	(19,159)	1,106
Accrued interest and taxes	**48,307**	(185,520)	174,107
Accounts payable and other current liabilities	**588,154**	352,489	205,256
Net cash provided by operating activities	**829,277**	1,457,788	978,129
Cash flows from financing activities:			
Long-term debt issued	**1,759,708**	490,840	—
Long-term debt repaid	**(524,700)**	(362,872)	(776,030)
Bonds repurchased and funds held in trust	**(439,855)**	—	—
Preferred stocks redeemed	—	—	(74,300)
Rate reduction notes repaid	**(246,300)**	(246,300)	(251,591)
Nuclear fuel financing — net	**8,651**	(37,287)	16,244
Short-term debt financing — net	**655,033**	326,423	147,537
Dividends paid	**(394,718)**	(685,731)	(1,129,812)
Net cash provided (used) by financing activities	**817,819**	(514,927)	(2,067,952)
Cash flows from investing activities:			
Additions to property and plant	**(1,095,633)**	(985,623)	(860,837)
Proceeds from sale of generating plants	**18,880**	—	1,203,039
Funding of nuclear decommissioning trusts	**(69,428)**	(115,937)	(162,925)
Proceeds from sales of marketable securities	**41,161**	84,306	32,127
Investments in other assets	**11,607**	15,870	(3,952)
Other	**3,430**	3,069	1,599
Net cash provided (used) by investing activities	**(1,089,983)**	(998,315)	209,051
Net increase (decrease) in cash and equivalents	**557,113**	(55,454)	(880,772)
Cash and equivalents, beginning of year	**26,046**	81,500	962,272
Cash and equivalents, end of year	**$ 583,159**	$ 26,046	$ 81,500
Cash payments for interest and taxes (in millions):			
Interest — net of amounts capitalized	**$ 303**	$ 287	$ 264
Taxes	**306**	433	405

The accompanying notes are an integral part of these financial statements.

Consolidated Statement of Changes in Common Shareholder's Equity

In thousands	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income	Retained Earnings (deficit)	Total Common Shareholder's Equity
Balance at December 31, 1997	$2,168,054	$ 334,031	$ 48,023	$ 1,407,834	$3,957,942
Net income				515,122	515,122
Unrealized gain on securities			13,784		13,784
Tax effect			(4,509)		(4,509)
Reclassified adjustment for gain included in net income			(30,002)		(30,002)
Tax effect			12,166		12,166
Dividends declared on common stock				(1,100,777)	(1,100,777)
Dividends declared on preferred stock				(24,632)	(24,632)
Stock option appreciation				(3,922)	(3,922)
Balance at December 31, 1998	$2,168,054	$ 334,031	$ 39,462	$ 793,625	$3,335,172
Net income				509,421	509,421
Unrealized gain on securities			45,813		45,813
Tax effect			(17,804)		(17,804)
Reclassified adjustment for gain included in net income			(77,241)		(77,241)
Tax effect			31,321		31,321
Dividends declared on common stock				(665,884)	(665,884)
Dividends declared on preferred stock				(25,889)	(25,889)
Stock option appreciation				(2,820)	(2,820)
Capital stock expense		1,007			1,007
Balance at December 31, 1999	$2,168,054	$ 335,038	$ 21,551	$ 608,453	$3,133,096
Net income (loss)				(2,028,344)	(2,028,344)
Unrealized gain on securities			8,027		8,027
Tax effect			(5,108)		(5,108)
Reclassified adjustment for gain included in net income			(41,161)		(41,161)
Tax effect			16,691		16,691
Dividends declared on common stock				(278,522)	(278,522)
Dividends declared on preferred stock				(21,443)	(21,443)
Stock option appreciation				(1,743)	(1,743)
Capital stock expense and other		(1,008)			(1,008)
Balance at December 31, 2000	**$2,168,054**	**$ 334,030**	**$ —**	**$(1,721,599)**	**$ 780,485**

Authorized common stock is 560 million shares with no par value.

The accompanying notes are an integral part of these financial statements.

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Southern California Edison Company (SCE) is a rate-regulated electric utility which supplies electric energy for its 4.3 million customers in central, coastal and Southern California. SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. In 1996, state lawmakers and the California Public Utilities Commission (CPUC) initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its generation portfolio. Today, those generating plants are owned by independent power companies. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates are to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, since the summer of 2000, the prices charged by generators and other sellers have escalated far beyond what SCE can currently charge its customers. See Note 3 for a further discussion.

SCE also produces electricity. On April 1, 1998, SCE began selling all of its electric generation through the California Power Exchange (PX) and Independent System Operator (ISO) and scheduling delivery through the ISO, as mandated by the CPUC's 1995 restructuring decision. By purchasing wholesale electricity through the PX and ISO, SCE satisfied the electric energy needs for customers who did not choose an alternative energy provider. The Federal Energy Regulatory Commission (FERC) issued an order on December 15, 2000, which, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX. On January 19, 2001, the PX announced that it will permanently cease operations by April 2001; on March 9, 2001, the PX filed for Chapter 11 bankruptcy protection.

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International, in either December 2000 or March 2001. See Note 2 for a further discussion.

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated. Certain prior-year amounts were reclassified to conform to the December 31, 2000, financial statement presentation.

SCE's accounting policies conform with accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. Since 1997, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate-recovery of generation-related assets. Application of such accounting principles to SCE's generation assets did not result in any adjustment of their carrying value.

SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Estimates

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to liquidity, regulatory matters, decommissioning and contingencies are further discussed in Notes 2, 3, 11 and 12 to the Consolidated Financial Statements, respectively.

Regulatory Balancing Accounts

During the rate freeze period, the difference between certain generation-related revenue and generation-related costs are being accumulated in the transition cost balancing account (TCBA). The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA; the losses are being amortized over the remaining transition period and accumulated in the TCBA.

In June 2000, SCE credited the TCBA for the estimated excess of the market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric generation assets. If there was a difference in the final market valuation, it would have been credited to or recovered from customers through the TCBA mechanism. Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the GABA transaction was reclassified back into the TCBA as of December 31, 2000.

The coal and hydroelectric generation balancing accounts tracked the differences between market revenue from coal and hydroelectric generation and the plants' operating costs after April 1, 1998. Overcollections were credited to the TCBA in 1998 and 1999, pursuant to a 1997 CPUC decision. Due to a January 4, 2001, interim CPUC decision, the balance at year-end 2000 was not credited to the TCBA, pending further testimony and evidence on the implications of crediting the overcollections to the transition revenue account (TRA) rather than the TCBA. The TRA is a CPUC-authorized regulatory asset in which SCE recorded the difference between revenue received from customers through currently frozen rates and the costs of providing service to customers, including power procurement costs.

On March 27, 2001 the CPUC issued a decision stating, among other things, that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called only for overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections, were reclassified to the TCBA, and the TCBA balance was recalculated to be a $2.9 billion undercollection.

Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the TCBA undercollection was charged to earnings as of December 31, 2000.

Balancing account undercollections and overcollections accrue interest. Income tax effects on all balancing account changes are deferred.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process. SCE's discontinuance of the application of accounting principles for rate-regulated enterprises to its generation assets in 1997 did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE must assess the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, and April 3, 2001, decisions (discussed in Note 3), including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. Until legislative and regulatory actions contemplated by the memorandum of understanding (MOU, as discussed in Note 3) occur, or other actions are taken, SCE is unable to conclude that its generation-related regulatory assets are probable of recovery through the rate-making process. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings as of December 31, 2000, to write off the TCBA and other regulatory assets (see below).

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including unamortized nuclear investment, flow-through taxes, unamortized loss on sale of plant, purchased-power settlements and other regulatory assets) were written off as of December 31, 2000. Unless the memorandum of understanding (MOU, as discussed in Note 3) is implemented or a rate-making mechanism is in place that would make recovery of SCE's TCBA-related regulatory assets probable, future net undercollections in the TCBA will be charged to earnings as losses are incurred. The regulatory and legislative actions set forth in the MOU are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions are taken, or other actions occur that make such recovery probable, and the rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Regulatory assets and liabilities included in the consolidated balance sheets are:

In millions December 31,	**2000**	1999
Generation-related:		
Unamortized nuclear investment – net	**$ —**	$ 1,366
Flow-through taxes	**—**	414
Unamortized loss on sale of plant	**—**	122
Purchased-power settlements	**—**	531
TCBA	**—**	1,044
Other – net	**—**	47
Subtotal	**—**	3,524
Rate reduction notes – transition cost deferral	**1,090**	707
Other:		
Flow-through taxes	**874**	859
Unamortized loss on reacquired debt	**273**	295
Environmental remediation	**52**	111
Regulatory balancing accounts and other	**(94)**	(42)
Subtotal	**1,105**	1,223
Total	**$2,195**	$ 5,454

The regulatory asset related to the rate reduction notes will be recovered over the terms of the rate reduction notes. The other regulatory assets and liabilities are being recovered through other components of the unbundled rates.

The unamortized nuclear investment regulatory asset was created during the second quarter of 1998. SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount in accordance with asset impairment accounting standards. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

Nuclear

SCE has been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account are part of the TCBA.

The nuclear rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period and through 2001 for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues (as discussed in Note 3), SCE is no longer able to conclude that the unamortized nuclear investment is probable of recovery through the rate-making process. As a result, the balance was written off as a charge to earnings as of December 31, 2000.

The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Palo Verde's existing nuclear unit incentive procedure will continue through 2001 only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle.

Under the MOU (discussed in Note 3), both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated.

Cash Equivalents

Cash equivalents include tax-exempt investments, time deposits and other investments with original maturities of three months or less.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. All such costs are expensed as incurred.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil and under the first-in, first-out method for coal.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year.

Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholder's equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Derivative Financial Instruments

SCE uses the hedge accounting method to record its derivative financial instruments. Hedge accounting requires an assessment that the transaction reduces risk, that the derivative be designated as a hedge at the inception of the derivative contract, and that the changes in the market value of a hedge move in an inverse direction to the item being hedged. Under hedge accounting, the derivative itself is not recorded on SCE's balance sheet. Mark-to-market accounting would be used if the hedge accounting criteria were not met. Interest rate differentials and amortization of premiums for interest rate caps are recorded as adjustments to interest expense. If the derivatives were terminated before the maturity of the corresponding debt issuance, the realized gain or loss on the transaction would be amortized over the remaining term of the debt.

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

AFUDC – equity was $11 million in 2000, $13 million in 1999 and $12 million in 1998. AFUDC – debt was $10 million in 2000, $11 million in 1999 and $8 million in 1998.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for both 2000 and 1999, and 4.2% for 1998.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2000, and December 31, 1999.

Related Party Transactions

Certain Edison Mission Energy (a wholly owned subsidiary of Edison International) subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements. Such sales to SCE were $716 million in 2000, $513 million in 1999 and

$535 million in 1998. As a result of SCE's liquidity crisis, SCE has deferred payments for power purchases from some of these facilities.

Purchased Power — PX/ISO

Transactions through the PX and ISO (reported net) were:

In millions Year ended December 31,	2000	1999	1998
Purchases	**$8,449**	$2,490	$1,984
Generation sales	**6,120**	1,719	1,348
Purchased power — PX/ISO — net	**$2,329**	$ 771	$ 636

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	2000	1999	1998
Gain on sale of marketable securities	**$ 41**	$ 77	$ 30
AFUDC	**21**	24	20
Other	**56**	61	79
Total other nonoperating income	**$ 118**	$ 162	$ 129
Provisions for regulatory issues and refunds	**$ 78**	$ 79	$ 66
Other	**32**	28	51
Total other nonoperating deductions	**$ 110**	$ 107	$ 117

Note 2. Liquidity Crisis

SCE's liquidity is primarily affected by debt maturities, dividend payments, capital expenditures and power purchases. Capital resources include cash from operations and external financings.

The increasing undercollection in the TRA, coupled with SCE's anticipated near-term capital requirements and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, have materially and adversely affected SCE's liquidity. As a result of the liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or the ISO; (2) $1.1 billion to power producers that are qualifying facilities (QFs); (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5-7/8% notes; and (6) $7 million of other obligations. Unpaid obligations will continue to accrue interest, as applicable. At March 31, 2001, SCE had estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations and preferred stock dividends in arrears (see below).

SCE is unable to obtain financing of any kind. As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, SCE has been unable to market its commercial paper and other short-term financial instruments. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness, which would allow SCE to pay all of its past due obligations.

On March 27, 2001, the CPUC ordered SCE to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay QFs within 15 days of the end of the QF's billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a payment when due will result in a fine equal to the amount owed. The CPUC also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than the Arizona border. The CPUC stated that the changes will probably result in lower QF power prices. The changes apply to all QFs, where appropriate, regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation and the approval of a 3¢per kWh rate increase (see Note 3). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the California Department of Water Resources (CDWR), and the QF decision discussed above could result in a shortfall to the CPA calculation of $1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International, in either December 2000 or March 2001. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. The total preferred stock dividends in arrears is $6 million as of March 31, 2001. As a result of the $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore, under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as dividends in arrears on SCE's cumulative preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

In addition to the above, SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. SCE's current cost-cutting measures are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future.

On April 9, 2001, SCE and the CDWR signed an MOU that, if approved by the legislature, would allow SCE to restore its financial health.

For a more detailed discussion on the matters discussed above, see Notes 3 through 7.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain. In addition, SCE's independent public accountant's opinion in the accompanying financial statements includes an explanatory paragraph which states that the issues resulting from the California energy crisis raise substantial doubt about SCE's ability to continue as a going concern.

Note 3. Regulatory Matters

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions. Until the various regulatory and legislative actions to implement the MOU are taken, or other actions occur that make such recovery probable, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000.

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets is no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover non-transition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue

(TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998.

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9 billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$3,561
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	577
Other transition costs	634
Total transition costs	7,862
Revenue available to recover transition costs	(4,984)
Unrecovered transition costs	$2,878

Unless the regulatory and legislative actions required to implement the MOU or other actions that make recovery probable are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000. In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund. The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the

CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens the past CPUC decision authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated company requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. SCE cannot provide assurance that the CPUC will adopt such a decision, or predict what effects this investigation or any subsequent actions by the CPUC may have on SCE.

In its interim order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢ per kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢ increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢ surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision.

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA account, whether over- or undercollected, be transferred on a monthly basis to the TCBA account, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis. SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thereby only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it will monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceedings. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X (see CDWR Power Purchases) continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. The three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over sellers exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above $430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Memorandum of Understanding with the CDWR

On April 9, 2001, Edison International and SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.

- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.

- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment-grade credit rating.

- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment-grade credit rating.

- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- An affiliate of Edison International will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for ten years from a power project currently under development. The Edison International affiliate will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.

- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.

- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. Edison International, SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

CDWR Power Purchases

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, Assembly Bill 1 (First Extraordinary Session) (AB 1X) was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of the CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR, which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered on an interim basis to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceeding), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late. Using these rates, SCE has billed customers $196 million for sales made by the CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Note 2) and the payments ordered to be made to CDWR, could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it cannot assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transactions. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost-recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Hydroelectric Market Value Filing

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfall from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the state if a sale of SCE's transmission assets is not completed under certain circumstances.

Note 4. Financial Instruments

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments, fluctuations in interest rates and energy prices, but prohibits the use of these instruments for speculative or trading purposes.

SCE used the mark-to-market accounting method for its gas call options, which were used to mitigate SCE's transition cost recovery exposure to increases in energy prices. Gains and losses from monthly changes in market prices were recorded as income or expense. In addition, the options' costs and market price changes were included in the TCBA. As a result, the mark-to-market gains or losses had no effect on earnings. In October 2000, SCE sold its gas call options resulting in a $190 million gain. The options covered various periods through 2001. The gains were credited to the TCBA.

The PX block forward market allowed SCE to purchase monthly blocks of energy and ancillary services for six days a week (excluding Sundays and holidays) for 8 to 16 hours a day, up to 12 months in advance of the delivery date.

SCE purchased block forward energy contracts through the PX, with various terms and prices, to hedge its exposure to fluctuations in energy prices. Due to the downgrades in SCE's credit ratings and SCE's failure to pay its obligations to the PX, the PX suspended SCE's market trading privileges and sought to liquidate SCE's block forward contracts. On February 2, 2001, SCE's motion for a preliminary injunction was denied, freeing the PX to liquidate the contracts and apply the proceeds to amounts owed by SCE to the PX. On the same day, the State seized the contracts for the benefit of the State before they could be sold by the PX. The State must compensate SCE for the reasonable value of the contracts. The PX has indicated that it will also seek to recover the monies that SCE owes to the PX from any proceeds realized from those contracts. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts. At December 31, 2000, these contracts had a nominal value of $234 million.

SCE also has bilateral forward contacts, which are considered normal purchases under accounting rules. At December 31, 2000, these contracts had a nominal value of $798 million. Due to its deteriorating credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and $379 million (nominal value) of its existing contracts were terminated by the counterparties in early 2001. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty. SCE is exposed to market risk resulting from changes in the spot market price for power. Changes in the value of bilateral forward contracts affects purchased power expense in the period when the power is delivered.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, and December 31, 1999, SCE had an interest rate swap agreement which fixed the interest rate at 5.585% for $196 million of debt due 2008; the receive rate on the swap averaged 3.839% in 2000. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008. The realized loss of $26 million will be amortized over a period ending in 2008.

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives to be recognized on the balance sheet at fair value.

Gains or losses from changes in fair value will be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure will be recorded as a separate component of shareholder's equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. On the implementation date, SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power purchase contracts (seized by the State on February 2, 2001) at fair value on its balance sheet. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates.

Fair values of financial instruments were:

In millions December 31,	2000		1999	
	Cost Basis	**Fair Value**	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	**$1,720**	**$2,505**	$1,650	$2,509
Equity investments	**—**	**—**	—	33
Gas call options	**—**	**—**	28	20
Financial liabilities:				
DOE decommissioning and decontamination fees	**36**	**31**	40	35
Interest rate swap	**—**	**21**	—	13
Long-term debt	**5,631**	**5,178**	5,137	5,044
Preferred stock subject to mandatory redemption	**256**	**157**	256	259

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts, equity investments and gas call options. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: quoted market prices for the interest rate swap; brokers' quotes for long-term debt and preferred stock; and discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximated fair value at December 31, 2000, and 1999.

As a result of investors' concerns regarding SCE's liquidity difficulties, its short-term debt and long-term debt fair values have decreased approximately $150 million and $500 million, respectively, from amounts reported at year-end.

Gross unrealized holding gains on debt and equity securities were:

In millions December 31,	2000	1999
Decommissioning trusts:		
Municipal bonds	**$193**	$239
Stocks	**384**	454
U.S. government issues	**136**	119
Short-term and other	**72**	47
	785	859
Equity investments	**—**	33
Total	**$785**	$892

There were no unrealized holding losses on debt and equity securities for the years presented.

Note 5. Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. As a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE has had to repurchase $549 million of pollution control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt.

Commercial paper intended to be refinanced for a period exceeding one year and used to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International. Due to SCE's recent credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	2000	1999
First and refunding mortgage bonds:		
2002-2026 (5.625% to 7.25%)	**$1,175**	$1,400
Rate reduction notes:		
2001-2007 (6.17% to 6.42%)	**1,724**	1,970
Pollution-control bonds:		
2008-2040 (5.125% to 7.2% and variable)	**1,216**	1,196
Bonds repurchased	**(420)**	—
Funds held by trustees	**(20)**	(2)
Debentures and notes:		
2001-2029 (5.875% to 7.625% and variable)	**2,450**	1,000
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**79**	71
Long-term debt due within one year	**(646)**	(571)
Unamortized debt discount — net	**(27)**	(27)
Total	**$5,631**	$5,137

Long-term debt maturities and sinking-fund requirements for the next five years are: 2001 — $646 million; 2002 — $746 million; 2003 — $1.4 billion; 2004 — $371 million; and 2005 — $246 million.

As a result of its liquidity crisis, SCE has taken steps to conserve cash, and has been forced to consider further alternatives for conserving cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations. As of March 31, 2001, SCE has failed to pay $206 million of maturing principal and accrued interest on its 5-7/8% notes. Under the indenture for SCE's senior unsecured notes, the failure to pay principal was an immediate event of default as to the one series of notes on which the principal was due. If an event of default occurs as to any series of senior unsecured notes, the trustee or the holders of 25% in principal amount of the notes of such series may declare the principal of the notes of that series to be immediately due and payable. In addition, SCE's failure to pay any obligation for borrowed money in an aggregate amount in excess of $10 million would constitute an event of default with respect to all of the senior unsecured notes and SCE's outstanding quarterly income preferred securities if not cured within 30 days after notice from the trustee of holders of the securities. No such notice has been received by SCE.

If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5-7/8% notes. (SCE has also deferred payment of maturing commercial paper. See Note 6 for a further discussion.) Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

In January 2001, three rating agencies lowered their credit ratings of SCE to substantially below investment grade. In mid-April, one agency removed SCE's credit ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other two agencies.

Note 6. Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including PX and ISO payments. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt consisted of:

In millions December 31,	2000	1999
Commercial paper	$ 700	$ 696
Bank loans	835	—
Floating rate notes	—	175
Amount reclassified as long-term debt	(79)	(71)
Unamortized discount	(5)	(4)
Total	$1,451	$ 796
Weighted average interest rates	6.9%	6.1%

At December 31, 2000, SCE had lines of credit totaling $1.65 billion, with $125 million available for the refinancing of certain variable-rate pollution control debt. The lines can be drawn at negotiated or bank index rates.

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit line. The proceeds were used in part to repurchase $420 million of pollution control bonds; the balance was retained as a liquidity reserve.

In late 2000, SCE was unable to complete the syndication of a $1 billion revolving credit agreement that was intended to finance current and expected balancing account undercollections and other operating requirements. In addition, SCE has been unable to market its commercial paper and other short-term financial instruments. And, in SCE's efforts to conserve cash, SCE has deferred payment of approximately $506 million of maturing commercial paper as of March 31, 2001.

Note 7. Preferred Stock

Authorized shares of preferred and preference stocks are: $25 cumulative preferred — 24 million; $100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stocks are redeemable.

Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2001 — zero; 2002 —$105 million; 2003 — $9 million; 2004 — $9 million; and 2005 — $9 million.

Cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2000 Shares Outstanding	December 31, 2000 Redemption Price	**2000**	1999
Not subject to mandatory redemption:				
$25 par value:				
4.08% Series	1,000,000	$25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Total			**$ 129**	$ 129
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$100.00	**$ 75**	$ 75
6.45	1,000,000	100.00	**100**	100
7.23	807,000	100.00	**81**	81
Total			**$ 256**	$ 256

In 1998, SCE redeemed 2.2 million shares of Series 5.8% and 193,000 shares of Series 7.23% preferred stock. SCE did not issue any preferred stock in the last three years.

SCE's Board of Directors did not declare the regular quarterly dividend for its cumulative preferred stock in 2001. As long as these dividends remain unpaid, SCE cannot declare or pay future cash dividends on any series of preferred stock or on its common stock, and SCE cannot repurchase any shares of its common stock. As a result of the $2.5 billion charge to earnings during fourth quarter 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains.

Note 8. Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under an income tax allocation agreement approved by the CPUC, SCE calculates its tax liability on a stand-alone basis.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are amortized over the lives of the related properties.

Notes to Consolidated Financial Statements

The components of the net accumulated deferred income tax liability were:

In millions December 31,	2000	1999
Deferred tax assets:		
Decommissioning	$ 98	$ 127
Accrued charges	379	247
Investment tax credits	81	113
Property-related	277	184
Regulatory balancing accounts	1,763	67
Unbilled revenue	101	122
Unrealized gains or losses	420	453
Other	56	92
Total	$3,175	$1,405
Deferred tax liabilities:		
Property-related	$2,184	$2,629
Capitalized software costs	264	225
Regulatory balancing accounts	1,632	448
Unrealized gains and losses	317	351
Other	242	502
Total	$4,639	$4,155
Accumulated deferred income taxes — net	$1,464	$2,750
Classification of accumulated deferred income taxes:		
Included in deferred credits	$2,009	$2,938
Included in current assets	545	188

The current and deferred components of income tax expense were:

In millions Year ended December 31,	2000	1999	1998
Current:			
Federal	$ (104)	$299	$450
State	—	79	101
	(104)	378	551
Deferred—federal and state:			
Accrued charges	(133)	(76)	(43)
Investment and energy tax credits — net	(41)	(45)	(74)
Property related	(302)	(194)	(169)
Regulatory asset amortization	251	7	63
Regulatory balancing accounts	(740)	371	177
State tax—privilege year	31	7	—
Unbilled revenue	20	(5)	(67)
Other	(4)	(5)	4
	(918)	60	(109)
Total	$(1,022)	$438	$442
Classification of income taxes:			
Included in operating income	$(1,007)	$451	$445
Included in other income	(15)	(13)	(3)

The composite federal and state statutory income tax rate was 40.551% for all years presented.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	2000	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
Capitalized software	**—**	(2.4)	(0.7)
Investment and energy tax credits	**1.4**	(4.4)	(6.8)
Property-related and other	**(6.6)**	9.3	11.4
State tax — net of federal deduction	**3.7**	8.5	6.9
Effective tax rate	**33.5%**	46.0%	45.8%

Note 9. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $29 million in 2000, $25 million in 1999 and $17 million in 1998.

Pension Plan

SCE has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. SCE recognizes pension expense as calculated by the actuarial method used for ratemaking. In April 1999, SCE adopted a cash balance feature for its pension plan.

Information on plan assets and benefit obligations is shown below:

In millions — Year ended December 31,	2000	1999
Change in benefit obligation		
Benefit obligation at beginning of year	**$2,075**	$2,251
Service cost	**63**	66
Interest cost	**155**	146
Plan amendment	**—**	(22)
Actuarial loss (gain)	**90**	(224)
Benefits paid	**(183)**	(142)
Benefit obligation at end of year	**$2,200**	$2,075
Change in plan assets		
Fair value of plan assets at beginning of year	**$3,078**	$2,552
Actual return on plan assets	**143**	620
Employer contributions	**29**	48
Benefits paid	**(183)**	(142)
Fair value of plan assets at end of year	**$3,067**	$3,078
Funded status	**$867**	$1,003
Unrecognized net loss (gain)	**(745)**	(1,018)
Unrecognized transition obligation	**22**	28
Unrecognized prior service cost	**118**	132
Recorded asset	**$262**	$ 145
Discount rate	**7.25%**	7.75%
Rate of compensation increase	**5.0%**	5.0%
Expected return on plan assets	**8.5%**	7.5%

Expense components were:

In millions Year ended December 31,	2000	1999	1998
Service cost	$ 63	$ 66	$ 59
Interest cost	155	146	141
Expected return on plan assets	(266)	(188)	(170)
Net amortization and deferral	(40)	12	14
Expense under accounting standards	(88)	36	44
Regulatory adjustment — deferred	88	14	11
Total expense recognized	$ —	$ 50	$ 55

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2000	1999
Change in benefit obligation		
Benefit obligation at beginning of year	$ 1,462	$ 1,545
Service cost	39	46
Interest cost	121	109
Actuarial loss (gain)	202	(185)
Benefits paid	(62)	(53)
Benefit obligation at end of year	$ 1,762	$ 1,462
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,283	$ 1,029
Actual return on plan assets	(40)	185
Employer contributions	19	122
Benefits paid	(62)	(53)
Fair value of plan assets at end of year	$ 1,200	$ 1,283
Funded status	$ (562)	$ (179)
Unrecognized net loss (gain)	141	(207)
Unrecognized transition obligation	323	349
Recorded asset (liability)	$ (98)	$ (37)
Discount rate	7.5%	8.0%
Expected return on plan assets	8.2%	7.5%

Expense components were:

In millions Year ended December 31,	2000	1999	1998
Service cost	$ 39	$ 46	$ 41
Interest cost	121	109	99
Expected return on plan assets	(106)	(79)	(62)
Net amortization and deferral	27	27	28
Total expense	$ 81	$ 103	$ 106

The assumed rate of future increases in the per-capita cost of health care benefits is 11.0% for 2001, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2000, by $277 million and annual aggregate service and interest costs by $30 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2000, by $239 million and annual aggregate service and interest costs by $25 million.

Stock Option Plans

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the Long-Term Incentive Compensation Program (prior program), which had been adopted by shareholders in 1992. Under the prior program, options on 1.5 million shares of Edison International common stock remain outstanding to officers and senior managers of SCE. The 1998 plan authorizes a limited annual award of Edison International common shares and options on shares. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, Edison International adopted an additional plan, the 2000 Equity Plan, which did not require shareholder approval.

Under the 1998 and 2000 plans, options on 8.6 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options expire 10 years after the date of grant, and vest over a period of up to five years. A portion of the executive long-term incentive program was awarded in the form of performance shares. The performance shares were restructured as retention incentives in December 2000, which will pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. Performance shares may still be awarded in 2001 and 2002. No special stock options may be exercised before five years have passed unless the stock appreciates to $25 (based on the average of 20 consecutive trading day closing prices). Edison International stock options awarded between 1994 and 1999 included a dividend equivalent feature. Dividend equivalents are accrued to the extend dividends are declared on Edison International common stock, and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards included a dividend equivalent feature. The 2000 stock option awards did not include dividend equivalents. Future stock option awards are not expected to include dividend equivalents.

All stock options have 10-year terms. Options issued after 1997 generally vest in 25% annual installments over a four-year period, although the vesting period for the May 2000 grants does not begin until May 2001. Stock options issued prior to 1998 had a three-year vesting period with one-third of the total award vesting after each of the first three years of the award term. If an option holder retires, dies or is permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE Management Committee (which was dissolved in 1993) will vest and be exercised upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an option holder is terminated other than by a qualifying event, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

The performance shares values are accrued ratably over a three-year performance period. SCE measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation programs was $4 million in 2000, $5 million in 1999 and $8 million in 1998.

Stock-based compensation expense under the fair value method of accounting would have resulted in pro forma net income (loss) available for common stock of $(2.054) billion in 2000, $484 million in 1999 and $491 million in 1998.

The fair value for each option granted, reflecting the basis for the above pro forma disclosures, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	2000	1999
Expected life	7 years—10 years	7 years
Risk-free interest rate	4.7%—6.0%	5.0% – 5.5%
Expected volatility	17%—46%	18%

The application of fair-value accounting to calculate the pro forma disclosures above is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

The weighted-average fair value of options granted during 2000 and 1999 was $5.50 per share option and $4.37 per share option, respectively. The weighted-average remaining life of options outstanding as of December 31, 2000, and December 31, 1999, was 7 years.

Note 10. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's share of expenses for each project is included in the consolidated statements of income.

The investment in each project as of December 31, 2000, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 41	$ 11	$ 1	60%
Pacific Intertie	230	80	6	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	463	351	3	48
Mohave (coal)	327	240	3	56
Palo Verde (nuclear)(1)	1,624	1,399	15	16
San Onofre (nuclear)(1)	4,268	3,874	22	75
Total	$6,953	$5,955	$50	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Notes 1 and 3.

Note 11. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Estimated remaining commitments for noncancellable leases at December 31, 2000, were:

Year ended December 31,	In millions
2001	$ 15
2002	12
2003	10
2004	9
2005	6
Thereafter	14
Total	$ 66

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which, effective June 1999, receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2026 and 2028 for the Palo Verde units. SCE could decommission San Onofre Units 2 and 3 as early as 2013. Palo Verde is planned to be decommissioned at the end of its operating license. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $106 million in 2000, $124 million in 1999 and $164 million in 1998. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.4 billion at December 31, 2000, and $1.3 billion at December 31, 1999. The estimated costs (recorded as a liability) to decommission San Onofre Unit 1 is approximately $342 million as of December 31, 2000.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31, 2000	1999
Municipal bonds	2001—2034	$ 548	$ 684
Stocks	—	531	482
U.S. government issues	2001—2029	421	351
Short-term and other	2001	220	133
Total		**$1,720**	$1,650

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $38 million in 2000, $58 million in 1999 and $63 million in 1998. Proceeds from sales of securities (which are reinvested) were $4.7 billion in 2000, $2.6 billion in 1999 and $1.2 billion in 1998. Approximately 90% of the trust fund contributions were tax-deductible.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered.

SCE has power-purchase contracts with certain qualifying facilities (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. As a result of the utility industry restructuring, SCE has entered into purchased-power settlements to end its contract obligations with certain qualifying facilities. The settlements are reported as power purchase contracts on the balance sheets.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $159 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2001 through 2005 are estimated below:

In millions	2001	2002	2003	2004	2005
Fuel supply contracts	$150	$107	$115	$ 97	$ 97
Purchased-power capacity payments	647	644	637	635	632

SCE's projected construction expenditures for 2001 total approximately $602 million. The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors.

Note 12. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Energy Crisis Issues

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with another lawsuit filed on March 15, 2001. SCE believes that its current and past accounting for the TRA undercollections and related items is appropriate and in accordance with accounting principles generally accepted in the United States.

As of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

SCE's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $75 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can now be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation expenditures in each of the next several years are expected to range from $5 million to $15 million. Recorded expenditures for 2000 were $13 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued by a mutual insurance company owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $19 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by

January 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE has not determined the costs for spent-fuel storage beyond that period, which would require new and separate interim storage facilities. Extended delays by the DOE could lead to consideration of costly alternatives involving siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to one mill per kilowatt-hour of nuclear-generated electricity sold after April 6, 1983.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2003 for Unit 2, and until 2004 for Units 1 and 3. Arizona Public Service Company, operating agent for Palo Verde, is constructing an interim fuel storage facility that is expected to be completed in 2002.

Quarterly Financial Data

	2000					1999				
In millions	**Total**	**Fourth**	**Third**	**Second**	**First**	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	$ 7,870	$ 1,755	$2,432	$1,853	$1,830	$7,548	$1,827	$2,310	$1,726	$1,685
Operating income (loss)	(1,652)	(2,402)	273	250	227	855	224	257	198	176
Net income (loss)	(2,028)	(2,485)	177	161	119	509	146	168	112	83
Net income (loss) available for common stock	(2,050)	(2,491)	172	156	113	484	141	160	106	77
Common dividends declared	279	—	92	91	96	666	117	269	111	169

Responsibility for Financial Reporting

The management of Southern California Edison Company (SCE) is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with accounting principles generally accepted in the United States and are based, in part, on management estimates and judgment.

SCE maintains systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. SCE believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

SCE's independent public accountants, Arthur Andersen LLP, are engaged to audit the financial statements in accordance with auditing standards generally accepted in the United States and to express an informed opinion on the fairness, in all material respects, of SCE's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity of financial information, the audit committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the Board of Directors the appointment of a firm of independent public accountants to conduct audits of its financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

SCE maintains high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and is committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

Thomas M. Noonan
Vice President
and Controller

Stephen E. Frank
Chairman of the Board, President
and Chief Executive Officer

April 12, 2001

To the Shareholders and the Board of Directors,
Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 2000, and 1999, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and changes in common shareholder's equity for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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 financial statements referred to above present fairly, in all material respects, the financial position of SCE and its subsidiaries as of December 31, 2000, and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

The accompanying financial statements have been prepared assuming that SCE will continue as a going concern. As discussed in Notes 2 and 3 to the consolidated financial statements, the current energy crisis in California has resulted in SCE incurring a loss from operations in the current year due to the uncertainty associated with its ability to collect certain costs through the regulatory process and has resulted in legal, regulatory and legislative uncertainties which have adversely impacted SCE's liquidity. These issues raise substantial doubt about SCE's ability to continue as a going concern. Management's plans in regard to these matters are also described in Notes 2 and 3. The financial statements do not include any adjustments relating to the recoverability and classification of asset carrying amounts or the amount and classification of liabilities that might result should SCE be unable to continue as a going concern.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
April 12, 2001

Board of Directors

Warren Christopher
Senior Partner,
O'Melveny & Myers,
Los Angeles, California

Stephen E. Frank
Chairman of the Board, President and
Chief Executive Officer,
Southern California Edison Company

Joan C. Hanley
The Former General Partner and Manager,
Miramonte Vineyards,
Rancho Palos Verdes, California

Carl F. Huntsinger
General Partner,
DAE Limited Partnership Ltd.,
Ojai, California

Charles D. Miller
Retired Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California

Luis G. Nogales
President,
Nogales Partners,
Los Angeles, California

Ronald L. Olson
Senior Partner,
Munger, Tolles and Olson,
Los Angeles, California

James M. Rosser
President,
California State University, Los Angeles,
Los Angeles, California

Robert H. Smith
Managing Director,
Smith and Crowley Incorporated,
Pasadena, California

Thomas C. Sutton
Chairman of the Board and
Chief Executive Officer
Pacific Life Insurance Company,
Newport Beach, California

Daniel M. Tellep
Retired Chairman of the Board,
Lockheed Martin Corporation,
Bethesda, Maryland

Edward Zapanta, M.D.
Physician and Neurosurgeon,
Torrance, California

Management Team

Stephen E. Frank
Chairman of the Board, President and
Chief Executive Officer

Harold B. Ray
Executive Vice President,
Generation Business Unit

Pamela A. Bass
Senior Vice President,
Customer Service Business Unit

John R. Fielder
Senior Vice President,
Regulatory Policy and Affairs

Robert G. Foster
Senior Vice President,
External Affairs

Richard M. Rosenblum
Senior Vice President,
Transmission and Distribution
Business Unit

Mahvash Yazdi
Senior Vice President and
Chief Information Officer

Emiko Banfield
Vice President,
Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President,
Corporate Communications

Bruce C. Foster
Vice President,
San Francisco Regulatory Operations

A.L. Grant
Vice President, Engineering and
Technical Services

Lawrence D. Hamlin
Vice President, Power Production

Harry B. Hutchison
Vice President,
Mass Customers

James A. Kelly
Vice President,
Regulatory Compliance

Russell W. Krieger
Vice President,
Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear Engineering
and Technical Services

Stephen E. Pickett
Vice President and General Counsel

Frank J. Quevedo
Vice President,
Equal Opportunity

Joseph P. Ruiz
Vice President and General Auditor

W. James Scilacci
Vice President and
Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

David Ned Smith
Vice President, Major Customers

Joseph J. Wambold
Vice President, Nuclear Business and
Support Services

Beverly P. Ryder
Secretary

(THIS PAGE INTENTIONALLY LEFT BLANK)

(THIS PAGE INTENTIONALLY LEFT BLANK)

Shareholder Information

Annual Meeting of Shareholders

Monday, May 14, 2001
1:30 p.m.
DoubleTree Hotel Ontario
222 N. Vineyard Avenue
Ontario, California 91764

Stock Listing and Trading Information

SCE Preferred Stock

SCE's preferred stocks are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05%, 6.45% and 7.23% series are not listed.

Where to Buy and Sell Stock

The listed preferred stocks may be purchased through any brokerage firm. Firms handling unlisted series can be located through your broker.

Transfer Agent and Registrar

Wells Fargo Bank Minnesota, N.A. maintains shareholder records and is the transfer agent and registrar for SCE preferred stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7:00 a.m. and 7:00 p.m. (Central Time), Monday through Friday, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks; and
- requests for access to online account information.

The address of Wells Fargo Shareowner Services is:

161 North Concord Exchange Street
South St. Paul, MN 55075-1139
FAX: (651) 450-4033
E-mail: stocktransfer@wellsfargo.com

SCE Web Address:
www.edisoninvestor.com

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL*® Company

2244 Walnut Grove Avenue, Rosemead, California 91770

626.302.1212

www.edison.com