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

# Form 10-K

**(Mark One)**

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

**For the fiscal year ended December 31, 2001**

**OR**

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

**For the transition period from to .**

**Commission File Number 1-9864**

# El Paso Tennessee Pipeline Co.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **76-0233548** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **El Paso Building 1001 Louisiana Street Houston, Texas** | **77002** |
| (Address of principal executive offices) | (Zip Code) |

**Registrant's telephone number, including area code: (713) 420-2600**

**Securities registered pursuant to Section 12(b) of the Act:**

| Title of Each Class | Name of each exchange on which registered |
|---|---|
| 8¼% Cumulative Preferred Stock, Series A ............................ | New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ 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. ☑

**State the aggregate market value of the voting stock held by non-affiliates of the registrant.**

Aggregate market value shall be computed by reference to the price at which the stock was sold, or the average bid and asked prices of such stock, as of the specified date within 60 days prior to the date of filing.

| Class of Voting Stock and Number of Shares Held by Non-affiliates at March 20, 2002 | Market Value Held by Non-affiliates |
|---|---|
| 8¼% Cumulative Preferred Stock, Series A, 6,000,000 shares | $302,160,000* |

* Based upon the closing price on the Composite Tape for the 8¼% Cumulative Preferred Stock, Series A, on March 20, 2002.

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

Common Stock, par value $0.01 per share. Shares outstanding on March 20, 2002: 1,971

**Documents Incorporated by Reference**

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: our definitive Proxy Statement for the 2002 Annual Meeting of Stockholders, to be filed not later than 120 days after the end of the fiscal year covered by this report, is incorporated by reference into Part III.

## EL PASO TENNESSEE PIPELINE CO.

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Below is a list of terms that are common to our industry and used throughout this document:

| | | | |
|---|---|---|---|
| /d | = per day | Mcfe | = thousand cubic feet of gas equivalents |
| Bbl | = barrels | MMcf | = million cubic feet |
| BBtu | = billion British thermal units | MMcfe | = million cubic feet of gas equivalents |
| BBtue | = billion British thermal unit equivalents | Mgal | = thousand gallons |
| Bcf | = billion cubic feet | MTons | = thousand tons |
| MBbls | = thousand barrels | MWh | = megawatt hours |
| MMBbls | = million barrels | MMWh | = thousand megawatt hours |
| MMBtu | = million British thermal units | TBtu | = trillion British thermal units |
| Mcf | = thousand cubic feet | | |

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

When we refer to "we", "us", "our", "ours", or "El Paso Tennessee", we are describing El Paso Tennessee Pipeline Co. and/or our subsidiaries.

# PART I

## ITEM 1. BUSINESS

### General

Prior to 1996, we operated as Tenneco Inc., an entity with operations in the automotive, energy, packaging and shipbuilding businesses. During the latter part of 1996, Tenneco distributed to its shareholders all of its businesses except for its energy business and some of its corporate and discontinued operations. In December 1996, El Paso Corporation acquired these remaining business operations and renamed us El Paso Tennessee Pipeline Co. At December 31, 2001, El Paso owned 100 percent of our common stock and greater than 80 percent of our equity value. The remaining equity value consists of approximately $300 million of outstanding preferred stock that is traded on the New York Stock Exchange.

Our principal operations include:

- natural gas transportation, gathering, processing and storage;
- energy and energy-related commodities and products marketing;
- power generation; and
- energy infrastructure facility development and operation.

### Segments

Our operations are segregated into three primary business segments: Pipelines, Merchant Energy and Field Services. These segments are strategic business units that provide a variety of energy products and services. We manage each segment separately, and each segment requires different technology and marketing strategies. For information relating to operating revenues, operating income, earnings before interest expense and income taxes (EBIT) and identifiable assets by segment, you should see Part II, Item 8, Financial Statements and Supplementary Data, Note 13, which is incorporated herein by reference.

Our Pipelines segment owns or has interests in approximately 16,400 miles of interstate natural gas pipelines in the U.S. and internationally. In the U.S., our systems connect the nation's principal natural gas supply regions to three of the largest consuming regions in the U.S.: the Gulf Coast, the Northeast and the Midwest. Our natural gas transmission operations are comprised of the Tennessee Gas Pipeline system, our wholly owned interstate pipeline system, as well as interests in the Portland Natural Gas Transmission system and the Bear Creek storage facility. Our international pipeline operations include our interests in three major operating natural gas transmission systems in Australia.

Our Merchant Energy segment is involved in a broad range of energy-related activities including asset ownership, customer origination, marketing and trading and financial services. We buy, sell and trade natural gas, power and other energy commodities in the U.S. and internationally. We are also a significant owner of electric generating capacity and own or have interests in 77 facilities in 16 countries. Our financial services businesses manage investments in the North American energy industry. Most recently, Merchant Energy has announced its expansion into the liquefied natural gas (LNG) business.

Our Field Services segment provides natural gas gathering, products extraction, fractionation, dehydration, purification, compression and intrastate transmission services. These services include gathering natural gas from more than 12,000 natural gas wells with over 17,000 miles of natural gas gathering and natural gas liquids pipelines, and 16 natural gas processing, treating and fractionation facilities located in some of the most active production areas in the U.S., including the San Juan Basin, east and south Texas, Louisiana and the Gulf of Mexico. We conduct our intrastate transmission operations through interests in five intrastate systems, which serve a majority of the metropolitan areas and industrial load centers in Texas as well as markets in Louisiana.

## Pipelines Segment

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through one wholly owned and four partially owned interstate transmission systems along with a natural gas storage facility. The table below details our wholly and partially owned interstate pipeline systems:

| Pipeline System | Supply and Market Region | Ownership Interest | Miles of Pipeline | Design Capacity[1] | Average Throughput[1] 2001 | 2000 | 1999 | Storage Capacity |
|---|---|---|---|---|---|---|---|---|
| | | (Percent) | | (MMcf/d) | (BBtu/d) | | | (Bcf) |
| Tennessee Gas Pipeline (TGP) | Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including New York City and Boston. | 100 | 14,200 | 6,194 | 4,405 | 4,354 | 4,253 | 95[3] |
| Dampier-to-Bunbury pipeline system | Extends from Dampier to Bunbury in western Australia. | 33 | 925 | 570 | 555 | 523 | 485 | — |
| Moomba-to-Adelaide pipeline system | Extends from Moomba to Adelaide in southern Australia. | 33 | 488 | 383 | 261 | 231 | 220 | — |
| Ballera-to-Wallumbilla pipeline system | Extends from Ballera to Wallumbilla in southwestern Queensland, Australia. | 33 | 470 | 115 | 71 | 71 | 59 | — |
| Portland Natural Gas Transmission | Extends from the Canadian border near Pittsburg, New Hampshire to Dracut, Massachusetts. | 30[2] | 300 | 214 | 123 | 110 | 61 | — |

(1) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.
(2) Our ownership interest increased from 19 percent to 30 percent effective June 2001.
(3) 5 Bcf of capacity is contracted from ANR Pipeline Company, our affiliate.

We own a 50 percent interest in Bear Creek Storage Company, which owns and operates an underground natural gas storage facility located in Louisiana. Southern Natural Gas Company, our affiliate, owns the remaining 50 percent interest. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to the Southern Natural Gas system and our TGP system under long-term contracts.

The following transmission system expansion projects have been approved by the Federal Energy Regulatory Commission (FERC):

| Project | Capacity | Description | Anticipated Completion Date |
|---|---|---|---|
| | (MMcf/d) | | |
| Stagecoach | 100 | Connects the Stagecoach Storage Field in New York to our mainline in Pennsylvania and expands our 300 Line to provide firm transportation service to interconnect with New Jersey Natural in Passaic, New Jersey. | Completed February 2002 |
| FPL project | 90 | Installation of compression and a meter to supply Florida Power and Light's facility in Rhode Island. | September 2002 |

*Regulatory Environment*

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each operates under separate FERC approved tariffs that establish rates, terms and conditions under which we provide services to our customers. Generally, the FERC's authority extends to:

- transportation and storage of natural gas, rates and charges;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipeline and marketing affiliates;

- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

Our wholly and partially owned domestic pipelines and storage facility have tariffs established through filings with the FERC that have a variety of terms and conditions, each of which affects our operations and our ability to recover fees for the services we provide. Generally, changes to these fees or terms of service can only be implemented upon approval by the FERC. In Australia, various regional and national agencies regulate the tariffs, rates and operating activities of natural gas pipelines.

Our interstate pipeline systems are also subject to the Natural Gas Pipeline Safety Act of 1968, which establishes pipeline safety requirements, the National Environmental Policy Act and other environmental legislation. Each has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our systems are in compliance with the applicable requirements.

We are also subject to regulation with respect to safety requirements in the design, construction, operation and maintenance of our interstate natural gas transmission systems and storage facility by the U.S. Department of Transportation. Operations on U.S. government land are regulated by the U.S. Department of the Interior.

For a discussion of significant rate and regulatory matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 10.

*Markets and Competition*

Our interstate transmission systems face varying degrees of competition from other pipelines, as well as alternative energy sources, such as electricity, hydroelectric power, coal and fuel oil. Also, the potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation may benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, or it may hamper demand by allowing a more effective use of surplus electric capacity through increased wheeling as a result of open access.

Our TGP system has approximately 430 firm and interruptible customers, including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. TGP has approximately 500 firm transportation contracts with remaining terms that extend from 1 month to 10 years and with an average remaining contract term of 5 years. Approximately 95 percent of our total capacity is subscribed under firm transportation agreements.

TGP faces strong competition in the Northeast, Appalachian, Midwest and Southeast market areas. It competes with interstate pipelines for deliveries to multiple-connection customers. Natural gas delivered on the TGP system competes with alternate fuels, principally oil and coal. TGP also competes with pipelines and local distribution companies to connect new loads. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and at the Canadian border.

Our ability to extend existing contracts or re-market expiring capacity with our customers is based on a variety of factors, including competitive alternatives, the regulatory environment at the local, state and federal levels and market supply and demand factors at the relevant extension or expiration dates. While we make every attempt to re-negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under our tariffs, we must, at times, discount our rates to remain competitive.

## Merchant Energy Segment

Our Merchant Energy segment is involved in a broad range of activities in the energy marketplace, including asset ownership, customer origination, marketing and trading and financial services.

**Asset Ownership**

Merchant Energy's Asset Ownership activities include ownership interests in domestic and international power generation and an emerging LNG business.

*Power Generation.* Our commercial focus in the power generation business is to either develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing attractive power purchase agreements. Under this strategy, we have become a significant U.S.-based independent power generator and currently own or have interests in 77 power plants in 16 countries. These plants represent 17,867 gross megawatts of generating capacity, 88 percent of which is sold under power purchase or tolling agreements with terms in excess of five years. Of these facilities, 66 percent are natural gas fired, 13 percent are geothermal and 21 percent are a combination of coal, natural gas liquids and hydroelectric.

A significant portion of our domestic activity is conducted within an unconsolidated affiliate, Chaparral Investors, L.L.C. Chaparral's primary strategy is to acquire power plants with above-market power contracts and restructure these contracts by offering a lower power sales cost to the plants' customers, which are typically electric utilities. Through Chaparral (an entity that we have also referred to in our public disclosures as Electron), we have invested in 39 U.S. power generation facilities with a total generating capacity of approximately 5,900 gross megawatts. We serve as the manager of Chaparral under a management agreement that expires in 2006, and are paid an annual performance-based fee for the services we perform under this agreement. Our activities as manager of Chaparral include:

- management of the operations and commercial activities of the facilities;
- project-level contract restructurings and monetizations;
- project financings, sales and acquisitions;
- identification, evaluation, negotiation and consummation of new investments in energy assets; and
- daily administration activities of accounting, tax, legal and treasury functions.

Internationally, our focus is on building energy infrastructure in developed economies, and to a lesser degree in selected emerging markets. Our primary areas of focus include Brazil, Europe, Korea and Japan. We principally conduct our Brazilian development activities within an unconsolidated affiliate that we refer to as Gemstone. Through our ownership interest in Gemstone, we have invested in five Brazilian power generation facilities with a total generating capacity of approximately 2,156 gross megawatts. We serve as the manager of Gemstone under a management agreement that expires in 2004. Our activities as manager of Gemstone are similar to those described above for Chaparral.

Detailed below are our power generation projects, by region, that are either operational or in various stages of construction:

| Region | Project Status | Number of Facilities | Gross Megawatts | Net[1] Megawatts |
|---|---|---|---|---|
| United States | | | | |
| East Coast | Operational | 18 | 2,917 | 1,989 |
| | Under Construction | 3 | 1,390 | 1,361 |
| Central | Operational | 5 | 475 | 433 |
| | Under Construction | 2 | 600 | 345 |
| West Coast | Operational | 26 | 1,694 | 665 |
| South America | Operational | 8 | 4,984 | 1,976 |
| | Under Construction | 1 | 470 | 282 |
| Asia | Operational | 8 | 2,935 | 1,406 |
| | Under Construction | 1 | 762 | 189 |
| Europe | Operational | 4 | 940 | 940 |
| Mexico | Operational | 1 | 700 | 700 |
| Total | | 77 | 17,867 | 10,286 |

(1) Net Megawatts represent our net ownership in the facilities.

*LNG.* Our LNG business contracts for LNG terminalling and regasification capacity, coordinates short and long-term LNG supply deliveries and is developing an international LNG supply, marketing and infrastructure business. As of December 31, 2001, our LNG business had contracted for 284 Bcf per year of LNG regasification capacity at three locations along the Eastern and Gulf of Mexico coastal regions of the U.S. as follows:

| Facility | Location | Contracted Capacity (MMcf/d) | Contracted In Service Date | Expiration Date |
|---|---|---|---|---|
| Elba Island | Georgia | 446 | 2001 | 2023 |
| Cove Point | Maryland | 250 | 2002 | 2022 |
| Lake Charles | Louisiana | 82 | 2003 | 2007 |

We have also contracted for 105 Bcf per year of long-term supplies of LNG at market sensitive prices, which will be delivered from the Caribbean beginning in 2002. In addition, we have contracted to lease four LNG tankers to transport LNG from supply areas to domestic and international market centers. These ships are currently being constructed by third parties with the first ship scheduled for delivery in 2003.

*Operations.* Merchant Energy has established an Operations group to manage the daily operations of Merchant Energy's worldwide assets. This group operates 18 generating facilities in the U.S. and four facilities in two foreign countries.

**Customer Origination, Marketing and Trading**

Our Merchant Energy segment is one of the largest energy marketers in North America, and manages a large network of energy assets, both owned and under contract, which are used in the delivery of natural gas and power. Merchant Energy's customer origination activities provide short and long-term supplies of energy commodities to a broad range of wholesale customers worldwide. These activities provide customers with alternatives to meet their energy supply needs and manage their associated energy risks through Merchant Energy's: (i) knowledge of the marketplace; (ii) network of delivery infrastructure; (iii) supply aggregation and transportation management capabilities; and (iv) valuation and integrated price risk management skills. Merchant Energy's marketing and trading groups trade natural gas, power, other energy commodities and related financial instruments in North America and Europe and provide pricing and valuation analysis for the entire segment. These groups manage the inherent risk of Merchant Energy's asset and trading portfolios using value-at-risk limits approved by the Audit Committee of El Paso's Board of Directors and attempt to optimize the value of the segment's asset portfolio.

During 2001, Merchant Energy's traded volumes increased across all commodity groups. Detailed below is the marketed and traded energy commodity volumes for each the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Volumes | | | |
| Physical | | | |
| Natural gas (BBtue/d) | 8,938 | 6,899 | 6,713 |
| Power (MMWh) | 220,668 | 116,749 | 79,361 |
| Other energy commodities (MBbls) | 19,444 | 7,772 | 4,990 |
| Financial settlements (BBtue/d) | 143,096 | 98,664 | 68,678 |

**Financial Services**

Our Financial Services group provides institutional and retail funds management and makes capital investments for Merchant Energy. It conducts these activities primarily through two subsidiaries, EnCap Investments, L.L.C. and Enerplus Global Investment Management, Inc.

EnCap is an institutional funds management firm specializing in financing independent oil and natural gas producers. EnCap manages four separate institutional oil and natural gas investment funds in the U.S. and serves as investment advisor to Energy Capital Investment Company PLC, a publicly traded investment company in the United Kingdom. Enerplus is an institutional and retail funds management firm in Canada. EnCap and Enerplus manage funds that had a combined market value of approximately $1.4 billion at December 31, 2001.

*Regulatory Environment*

Merchant Energy's domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to its rates, terms and conditions of service. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Its cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act with respect to rates, procurement and provision of services and operating standards. Its power generation activities are also subject to federal and state environmental regulations, including the U.S. Environmental Protection Agency (EPA) regulations. We believe that our operations are in compliance with the applicable requirements.

Merchant Energy's foreign operations are regulated by numerous governmental agencies in the countries in which these projects are located. Many of the countries in which Merchant Energy conducts and will conduct business have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures and their interpretation and application by administrative agencies are relatively new and sometimes limited. Many detailed rules and procedures are yet to be issued, and we expect that the interpretation of existing rules in these jurisdictions will evolve over time. We believe that our operations are in compliance with all environmental laws and regulations in the applicable foreign jurisdictions.

*Markets and Competition*

Merchant Energy maintains a diverse supplier and customer base. During 2001, its activities served over 1,000 suppliers and over 900 customers around the world.

Merchant Energy's trading, marketing and energy infrastructure development businesses operate in a highly competitive environment. Its primary competitors include:

- affiliates of major oil and natural gas producers;
- multi-national energy infrastructure companies;

- large domestic and foreign utility companies;
- affiliates of large local distribution companies;
- affiliates of other interstate and intrastate pipelines; and
- independent energy marketers and power producers with varying scopes of operations and financial resources.

Merchant Energy competes on the basis of price, access to production, imbalance management, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served by Merchant Energy is influenced directly or indirectly by energy market economics.

Many of Merchant Energy's generation facilities sell power pursuant to long-term agreements with investor-owned utilities in the U.S. The terms of its power purchase agreements for its facilities are such that Merchant Energy's revenues from these facilities are not significantly impacted by competition from other sources of generation. The power generation industry is rapidly evolving and regulatory initiatives have been adopted at the federal and state level aimed at increasing competition in the power generation business. As a result, it is likely that when the power purchase agreements expire, these facilities will be required to compete in a significantly different market in which operating efficiency and other economic factors will determine success. Merchant Energy is likely to face intense competition from generation companies as well as from the wholesale power markets. The successful acquisition of new business opportunities is dependent on Merchant Energy's ability to respond to requests to provide new services, mitigate potential risks and maintain strong business development, legal, financial and operational support teams with experience in the marketplace.

## Field Services Segment

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. It also provides well-ties and real-time information services, including electronic wellhead gas flow measurement.

Field Services' assets include natural gas gathering and natural gas liquids pipelines, treating, processing and fractionation facilities in the San Juan Basin, referred to as the Western Division; in the producing regions of east and south Texas, the Permian Basin and the Gulf of Mexico, referred to as the Central Division; and in Louisiana, referred to as the Eastern Division.

Our Field Services segment also owns 7 percent of the common units of El Paso Energy Partners L.P. El Paso Energy Partners is a master limited partnership that provides gathering, transportation, fractionation, storage and other related activities for producers of natural gas, natural gas liquids and oil. A subsidiary of our parent company serves as the general partner of El Paso Energy Partners.

The following tables provide information on Field Services' natural gas gathering and transportation facilities, its processing facilities and the facilities of its equity method investees:

| Gathering & Treating | Ownership Interest | Miles of Pipeline[1] | Throughput Capacity[2] | Average Throughput[2] 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|
| | (Percent) | | (MMcfe/d) | | (BBtue/d) | |
| Central Division[3] | 100 | 9,480 | 5,220 | 3,769 | 1,375 | 891 |
| Eastern Division | 100 | 1,661 | 1,162 | 491 | 835 | 1,184 |
| Western Division | 100 | 5,555 | 1,200 | 1,197 | 1,039 | 1,262 |
| El Paso Energy Partners | 7 | 874 | 277 | 157 | 206 | 186 |

| Processing Plants | Ownership Interest | Inlet Capacity[2] | Average Inlet Volume[2] 2001 | 2000 | 1999 | Average Natural Gas Liquids Sales[2] 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|---|---|
| | (Percent) | (MMcf/d) | | (BBtu/d) | | | (Mgal/d) | |
| Central Division[3] | 100 | 1,730 | 1,566 | 296 | 242 | 3,120 | 399 | 202 |
| Western Division | 100 | 650 | 622 | 638 | 650 | 1,670 | 1,772 | 1,756 |
| Eastern Division | 100 | 135 | 63 | 65 | 140 | 163 | 173 | 264 |
| Coyote Gulch | 50 | 120 | 106 | 87 | 97 | — | — | — |

(1) Mileage amounts are approximate for the total systems and have not been reduced to reflect Field Services' net ownership.

(2) All volumetric information reflects Field Services' net interest.

(3) The Central Division includes our acquisition of PG&E's Texas Midstream operations in December 2000. In February 2002, we announced our plan to sell 9,400 miles of intrastate pipelines and 1,300 miles of gathering systems to El Paso Energy Partners.

*Regulatory Environment*

Some of Field Services' operations are subject to regulation by the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each entity subject to the FERC's regulation operates under separate FERC approved tariffs with established rates, terms and conditions of service.

Some of Field Services' operations are also subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of Field Services' operations are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and the National Environmental Policy Act. Each of the pipelines has a continuing program of inspection designed to keep all of the facilities in compliance with pollution control and pipeline safety requirements, and Field Services believes that these systems are in compliance with applicable requirements.

*Markets and Competition*

Field Services competes with major interstate and intrastate pipeline companies in transporting natural gas and natural gas liquids. Field Services also competes with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and natural gas liquids. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service and access to favorable downstream markets.

## Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 10, and is incorporated herein by reference.

## Employees

As of March 20, 2002, we had approximately 5,900 full-time employees, of which 233 are subject to collective bargaining arrangements.

**Executive Officers of the Registrant**

Our executive officers as of March 20, 2002, are listed below.

| Name | Office | Age |
|---|---|---|
| William A. Wise | Chairman of the Board, President and Chief Executive Officer | 56 |
| H. Brent Austin | Executive Vice President and Chief Financial Officer | 47 |
| Joel Richards III | Executive Vice President | 55 |
| Peggy A. Heeg | Executive Vice President: Law | 42 |

Mr. Wise became our Chairman of the Board, President and Chief Executive Officer in December 1996. Mr. Wise has been Chief Executive Officer of El Paso since January 1990 and Chairman of El Paso's Board of Directors since January 2001. He was also Chairman of El Paso's Board of Directors from January 1994 until October 1999. Mr. Wise became the President of El Paso in July 1998 and also served in that capacity from January 1990 to April 1996. Mr. Wise is a member of the Board of Directors of Praxair, Inc. and is the Chairman of the Board of El Paso Energy Partners Company, the general partner of El Paso Energy Partners, L.P.

Mr. Austin has been our Executive Vice President and Chief Financial Officer since June 1997. From December 1996 until June 1997, he was Senior Vice President and Chief Financial Officer. Mr. Austin has been Executive Vice President of El Paso since May 1995. He has been El Paso's Chief Financial Officer since April 1992. Prior to that period, he served in various positions with Burlington Resources Inc. and Burlington Northern Inc. Mr. Austin is a member of the Board of Directors of El Paso Energy Partners Company, the general partner of El Paso Energy Partners, L.P.

Mr. Richards has been our Executive Vice President since June 1997. From December 1996 until June 1997, he was Senior Vice President. Mr. Richards has been Executive Vice President of El Paso since December 1996. From January 1991 until December 1996, he was Senior Vice President of El Paso.

Ms. Heeg has been our Executive Vice President: Law and El Paso's Executive Vice President and General Counsel since January 1, 2002. She was Senior Vice President and Deputy General Counsel of El Paso from April 2001 to December 2001 and Vice President and Associate General Counsel for El Paso's regulated pipelines from 1997 to 2001. Ms. Heeg has held various positions in the legal department of Tenneco Energy and El Paso since 1996.

Executive officers hold offices until their successors are elected and qualified, subject to their earlier removal. Each of these elected officers also hold offices and/or director positions with our affiliated entities.

## ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated by reference herein.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions that do not materially detract from the value of these properties or our interests therein, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

## ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 10, and is incorporated herein by reference.

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

None.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

All of our common stock, par value $0.01 per share, is owned by El Paso and is not publicly traded. Our Series A preferred stock is traded on the New York Stock Exchange under the symbol EPG_p.

We pay dividends on our common stock from time to time from legally available funds that have been approved for payment by our Board of Directors.

We pay dividends on our Series A preferred stock on a quarterly basis. The dividend rate on our preferred stock is 8¼% per annum (2.0625% per quarter). We pay dividends on March 31, June 30, September 30 and December 31 of each year. All dividends payable on outstanding shares of our preferred stock for the quarterly periods ending on or prior to December 31, 2001, have been paid in full.

### ITEM 6. SELECTED FINANCIAL DATA

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2001 | 2000 | 1999 | 1998 | 1997 |
| | | | (In millions) | | |
| Operating Results Data:[1] | | | | | |
| Operating revenues[2] | $32,982 | $20,788 | $9,670 | $8,540 | $8,842 |
| Merger-related costs and asset impairment charges[3] | 108 | 11 | 75 | — | — |
| Income before extraordinary items and cumulative effect of accounting change | 669 | 482 | 186 | 221 | 135 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2001 | 2000 | 1999 | 1998 | 1997 |
| | | | (In millions) | | |
| Financial Position Data:[1] | | | | | |
| Total assets[2] | $19,995 | $19,465 | $9,764 | $8,393 | $9,200 |
| Long-term debt, less current maturities | 1,563 | 1,845 | 1,459 | 1,467 | 1,083 |
| Minority interests | 356 | 51 | 88 | 74 | 80 |
| Stockholders' equity | 3,844 | 3,154 | 2,430 | 2,172 | 1,935 |

(1) Our operating results and financial position reflect the acquisition in December 2000 of PG&E's Texas Midstream operations. This acquisition was accounted for as a purchase and therefore operating results are included in our results prospectively from the purchase date.

(2) The increase to our 2000 operating revenues and total assets reflects the significant growth in our Merchant Energy operations.

(3) Our 2001 and 2000 costs relate primarily to El Paso's merger with Coastal, and our 1999 costs relate primarily to El Paso's merger with Sonat.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Results of Operations

For the three years ended December 31, 2001, 2000 and 1999, we had net income of $717 million, $540 million and $173 million. The 2001 results included merger-related costs and asset impairments totaling $108 million, or $73 million after taxes, related to El Paso Corporation's merger with The Coastal Corporation. See a discussion of these charges in Item 8, Financial Statements and Supplementary Data, Note 3. In addition, we recorded an extraordinary gain of $38 million, net of income taxes, as a result of a Federal Trade Commission (FTC) ordered sale of our Midwestern Gas Transmission system. This order arose as part of El Paso's merger with Coastal and is discussed further in Item 8, Financial Statements and Supplementary Data, Note 2. We also recorded a cumulative effect of accounting change of $10 million, net of income taxes, related to our adoption of Emerging Issues Task Force Topic D-105 *Accounting in Consolidation for Energy Trading Contracts between Affiliated Entities When the Activities of One but not Both Affiliates Are Within the Scope of Issue 98-10*, that we adopted during the fourth quarter of 2001. See a discussion of this accounting change in Item 8, Financial Statements and Supplementary Data, Note 1. For the year ended December 31, 2000, merger-related charges were $11 million, or $7 million net of income taxes, and we recorded extraordinary gains on the FTC ordered sales of our East Tennessee Natural Gas Company and our interest in Oasis Pipeline Company totaling $58 million, net of income taxes. The charge related to the sale of East Tennessee resulted from El Paso's merger with Sonat Inc in 1999 and the charge from the sale of Oasis related to El Paso's acquisition of Pacific Gas & Electric's Texas Midstream assets. For the year ended December 31, 1999, merger-related costs and asset impairments related to El Paso's merger with Sonat reduced net income by $75 million, or $52 million after taxes. We also recorded a cumulative effect of accounting change of $(13) million, net of income taxes. Net income for each of the three years ended December 31, 2001, excluding the after-tax effects of these charges and extraordinary items, would have been $742 million, $489 million and $238 million.

### Segment Results

Our three segments: Pipelines, Merchant Energy and Field Services are strategic business units that offer a variety of different energy products and services, each requiring different technology and marketing strategies. Our operating results reflect the acquisition of PG&E's Texas Midstream operations as of the purchase date. We evaluate segment performance based on earnings before interest expense and taxes, or EBIT. To the extent possible, results of operations have been reclassified to conform to the current business segment presentation, although such results are not necessarily indicative of the results which would have been achieved had the revised business segment structure been in effect during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the Merchant Energy and the Field Services segments. For a further discussion of the individual segments, see the discussion of our businesses beginning on page 1, as well as Item 8, Financial Statements and Supplementary Data, Note 13.

The following table presents EBIT by segment and in total, including the merger-related costs and asset impairment charges discussed above, for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| **Earnings Before Interest Expense and Income Taxes** | | | |
| Pipelines | $ 322 | $ 354 | $383 |
| Merchant Energy | 901 | 563 | 3 |
| Field Services | 81 | 88 | 78 |
| Segment EBIT | 1,304 | 1,005 | 464 |
| Corporate and other | (7) | (17) | (17) |
| Consolidated EBIT | $1,297 | $ 988 | $447 |

**Pipelines**

Our Pipelines segment operates our interstate pipeline business. Our pipeline systems operate under separate tariffs that govern their operations, terms and conditions of service and rates. Operating results for our pipeline systems have generally been stable because the majority of the revenues are based on fixed reservation charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions, system expansions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines and fluctuations in natural gas prices. Results of operations of the Pipelines segment were as follows for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Operating revenues | $ 730 | $ 776 | $ 852 |
| Operating expenses | (429) | (441) | (492) |
| Other income | 21 | 19 | 23 |
| Earnings before interest and income taxes | $ 322 | $ 354 | $ 383 |
| Total throughput (BBtu/d)[1] | 4,441 | 4,375 | 4,265 |

[1] Throughput volumes exclude those related to pipeline systems sold in connection with El Paso's Coastal and Sonat mergers including the Midwestern Gas Transmission and East Tennessee Natural Gas systems.

**Year Ended December 31, 2001 Compared to Year Ended December 31, 2000**

Operating revenues for the year ended December 31, 2001, were $46 million lower than the same period in 2000. This decrease was due to lower 2001 revenues resulting from remarketed contracts on TGP during 2000 and the sales of the Midwestern Gas Transmission system in April 2001 and the East Tennessee Natural Gas system in the first quarter of 2000, including contract quantity reductions or cancellations on our pipeline system by customers of our affiliate, East Tennessee Natural Gas Company, resulting from the FTC ordered sale of this system. Also contributing to the decrease were lower transportation revenues on throughput in 2001 as a result of higher proportion of short versus long hauls compared to 2000. Our revenues from period to period are impacted not only by the overall volume of gas transported, but the distances this gas is shipped on our system. Partially offsetting the decrease was higher sales of excess natural gas in 2001, the favorable resolution of issues related to natural gas purchase contracts and higher revenues from other transportation services.

Operating expenses for the year ended December 31, 2001, were $12 million lower than the same period in 2000. The decrease was due to lower corporate allocations and operating expenses as a result of cost savings following our parent company's merger with Coastal, decreased depreciation expense resulting from the retirement of assets and reduced operating and depreciation expenses from the sales of the Midwestern and

East Tennessee systems. The decrease was partially offset by higher electric compression costs in 2001 and higher project development costs.

**Year Ended December 31, 2000 Compared to Year Ended December 31, 1999**

Operating revenues for the year ended December 31, 2000, were $76 million lower than the same period in 1999. The decrease was due to the impact of the sale of our East Tennessee Pipeline system in the first quarter of 2000, which El Paso was required to sell under an FTC order as a condition to completing the Sonat merger. Also contributing to the decrease was the impact of customer settlements and contract terminations in 2000, and the favorable resolution of regulatory issues and sale of emission credits in 1999. The decreases were partially offset by higher revenues from transportation and other services due to improved average throughput in 2000.

Operating expenses for the year ended December 31, 2000, were $51 million lower than the same period in 1999. The decrease was due to cost efficiencies following El Paso's merger with Sonat and lower operating costs on our East Tennessee Pipeline system, which was sold in the first quarter of 2000.

Other income for the year ended December 31, 2000, was $4 million lower than the same period in 1999 primarily due to a gain on the sale of non-pipeline assets recorded in 1999.

**Merchant Energy**

Our Merchant Energy segment is involved in a wide range of activities in the wholesale energy markets, including asset ownership, customer origination, marketing and trading and financial services. Each of the markets served by Merchant Energy is highly competitive and is influenced directly or indirectly by energy market economics.

*Asset Ownership*

Merchant Energy's asset ownership activities include domestic and international power plants and an emerging LNG business. In its power asset business, Merchant Energy owns or has interests in 77 plants in 16 countries. The segment's domestic power activities are principally conducted through Chaparral Investors, L.L.C., an unconsolidated affiliate in which Merchant Energy has a 20 percent ownership interest.

*Chaparral.* Chaparral was formed in 1999. Through its subsidiaries, Chaparral (also referred to as Electron) owns domestic power assets and is funded with third party capital (80%) and El Paso capital (20%). A subsidiary in our Merchant Energy segment manages the daily activities of Chaparral's assets and investments and are paid an annual management fee. The basic strategy of Chaparral is:

- to acquire power facilities with attractive power contracts;
- to develop facilities that will operate under long-term tolling agreements;
- to restructure the power sales, fuel supply and credit agreements of PURPA facilities;
- to monetize these restructured arrangements to fund operations and grow the venture; and
- to operate these facilities in a fully deregulated environment in a manner that enhances their value.

Chaparral was formed in order to obtain low cost financing to grow new business activities and to generate a stable fee-based income stream. Merchant Energy's annual management fee is equal to 20% of the net present value of the assets of Chaparral and must be approved by the third party investor. This net present value, or NPV, represents the present value of anticipated future cash flows of Chaparral's assets, net of its liabilities, less the estimated cost to liquidate all third party capital. As of December 31, 2001, Chaparral held assets with an NPV totaling approximately $925 million.

As of December 31, 2001, Chaparral's total assets were $2.5 billion and its liabilities were $1.6 billion. Total third party capital in Chaparral was approximately $1.15 billion, of which the debt component was $1.0 billion. In order to lower the cost of this debt, El Paso provided a contingent equity support arrangement to the third party debtholders. El Paso plans to amend this arrangement and replace it with an El Paso financial guaranty in 2002.

The future success of Chaparral will be dependent upon its ability to successfully restructure its existing assets, as well as acquire additional power facilities. Chaparral may face increased competition in the future for properties and facilities that are increasingly complicated to acquire and restructure. In addition, if not renegotiated or renewed, the debt financing that supports Chaparral matures in the first quarter of 2003. While it is our intent to renew these agreements, there are no guarantees that the financial investors will continue to participate or that third party capital will be available for investment.

Merchant Energy conducts a variety of transactions with Chaparral and generates earnings in several ways, including a performance-based management fee, equity earnings from Chaparral's activities and margins on risk management activities where Merchant Energy serves as the commodity provider for many of Chaparral's fuel and power purchase contracts. Chaparral also reimburses Merchant Energy for general and administrative expenses incurred on its behalf. During 2001, Merchant Energy earned $147 million in management fees from Chaparral and was reimbursed $20 million for general and administrative expenses. It also recognized $75 million in equity earnings. For 2002, the management fee will increase to approximately $185 million as approved by Chaparral's third party investor in the fourth quarter of 2001. This management fee increase reflects the growth that has occurred in the Chaparral asset portfolio. Assumptions used in establishing the annual management fee include estimates of future energy prices, future demand for power, timing and terms of contract restructurings and future interest rates. These assumptions are based on a combination of quoted market prices and rates, models which project future market changes and anticipated demand, and other variables. Changes in these assumptions can impact the annual management fee from year to year and these changes can be material.

From time to time, we and other El Paso affiliates enter into transactions with Chaparral and its affiliates to sell power assets. Merchant Energy's fiduciary responsibilities under its management agreement with Chaparral require that these transactions be entered into at fair and reasonable values. To ensure fairness, significant transactions are evaluated and approved by the third party investor of Chaparral as well as El Paso's Board of Directors. During 2001, Chaparral acquired power assets from us with a fair value of $94 million. We did not recognize any gains or losses on these transactions.

*International Power Assets and Gemstone.* Internationally, Merchant Energy's power assets consist primarily of investments in joint ventures that construct and operate power facilities and other infrastructure assets around the world. In Brazil, these activities are conducted through Gemstone, an unconsolidated affiliate through which Merchant Energy plans to expand its power investments in that country. Gemstone was formed in late 2001 with a third party investor primarily to generate low-cost funds for financing power plants in Brazil and to reduce risk through the introduction of third party equity. Total third party capital in Gemstone as of December 31, 2001 was $1 billion, of which the debt component was $950 million. To lower the cost of this debt, El Paso provided a contingent equity support arrangement to the third party debtholders. El Paso plans to amend this arrangement and replace it with an El Paso financial guaranty in 2002.

Brazil's power infrastructure has primarily been based on the use of hydroelectric power generation. The success of Gemstone in the future will be based on the demand for natural gas fired generation in Brazil, which may be significantly impacted by the availability of competing generation, such as hydroelectric power generation, which is less expensive to operate and more abundant. Furthermore, there are numerous risks in operating internationally which could impact Gemstone's ultimate success.

Earnings from Merchant Energy's international power activities, including Gemstone, are derived primarily through equity earnings from these investments and will be dependent on the ultimate success of privately owned power generation and infrastructure development in countries where Merchant Energy does business. During 2001, Merchant Energy recorded net equity income from Gemstone of $2 million.

*Liquified Natural Gas (LNG).* In addition to its power business, Merchant Energy has an emerging global LNG operation. In 2001, Merchant Energy increased the scope of its activities in LNG, with full operations expected in 2003 and 2004. The success of this business will be based substantially on the worldwide supply of natural gas and demand for LNG which will depend on strong natural gas prices and LNG shipping and terminalling infrastructure.

*Customer Origination, Marketing and Trading*

Merchant Energy's customer origination, marketing and trading activities provide energy supply and risk management solutions for its customers and affiliates involving natural gas, power and other energy commodities. Merchant Energy assists its customers with energy supply aggregation, storage and transportation management and provides them with an array of risk management products. Merchant Energy also conducts a substantial energy trading business that executes proprietary trading strategies and manages the segment's risk across multiple commodities and over seasonally fluctuating energy demands using consistent methodologies. During 2001 and 2000, U.S. energy supply and demand resulted in substantial volatility in the energy markets that significantly impacted Merchant Energy's earnings.

Merchant Energy's customer origination, marketing and trading groups account for their activities using mark-to-market accounting. Under this accounting method, financial instruments, physical commodity positions and contractual energy-related transactions are recorded on the balance sheet and the income statement at their fair value at the time they are entered into. Subsequent to their inception, the transactions continue to be adjusted in the balance sheet and income statement for changes in their fair value until they are settled. Determining the fair value of these positions at inception and until settlement principally involves the use of actively quoted prices and, to a lesser degree, other valuation methods, including models that rely on actively quoted prices. Approximately 9% of the value of our mark-to-market portfolio is based on model valuations (i.e., not on active market quotes). Most of these models are options-based valuations and involve contracts related to physical assets. Examples of contracts that are generally valued using models include natural gas pipeline capacity, natural gas storage contracts and, to a lesser extent, power plant tolling agreements. Modeling allows us to value these contracts, as well as manage them more effectively, providing lower cost service to our customers, and to effectively measure and manage the risk associated with them on a daily basis. Almost all of the model-based valuations we employ are spread option valuations, such as location spread options (pipeline capacity), time spread options (natural gas storage capacity) and spark spread options (natural gas-fired power plant tolling). The price data underlying these models is based, in part, on market data and our estimates of future prices for periods in which market data is limited. An important variable in these models is the volatility of the prices underlying the contracts and the correlation of the prices underlying the contracts. There is limited market price data related to correlations and volatilities although significant implicit data does exist. We use this implicit market data and historical data to determine volatilities and correlation for calculation of these models. We believe these calculations to be reliable predictors of value over time. In addition, Merchant Energy maintains a risk controls group that verifies all market price data for accuracy, independently of the marketing and trading groups and this group conducts these activities on both actively quoted and model-derived information. Further, to the extent there is uncertainty of the amounts we will ultimately realize from these transactions, we adjust the amounts we recognize as income until these uncertainties are resolved. These estimates are adjusted as assumptions change or as transactions move closer to settlement and better estimates become available.

As of December 31, 2001, the fair value of our trading-related price risk management activities is $1,337 million, and total margins generated from these activities during 2001 were $675 million.

The following table details the fair value of Merchant Energy's trading price risk management activities by year of maturity and valuation methodology. The amounts reflected as prices actively quoted are based on values determined by market quotes and other actively traded data, primarily NYMEX and other exchange-based information, including broker quotes. The amounts reflected as prices based on models and other valuation methods represent the fair value of contracts calculated based on internal models using the methods discussed above.

**Fair Value of Trading Price Risk Management Contracts as of December 31, 2001**

| Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity 6 to 10 Years | Maturity Beyond 10 Years | Total Fair Value |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| Prices actively quoted | $401 | $384 | $266 | $102 | $ 61 | $1,214 |
| Prices based on models and other valuation methods | 39 | 76 | 47 | (12) | (27) | 123 |
| Total net trading assets | $440 | $460 | $313 | $ 90 | $ 34 | $1,337 |

A reconciliation of our 2001 trading activities is as follows (in millions):

| | |
|---|---|
| Fair value of net trading assets as of December 31, 2000 | $ 2,143 |
| Fair value of contracts settled during the period | (1,973) |
| Initial recorded value of new contracts | 160 |
| Change in fair value of contracts | 812 |
| Changes in fair value attributable to changes in valuation techniques | 2 |
| Cumulative effect of change in accounting principle | 17 |
| Other | 176 |
| Net change in contracts outstanding during the period | (806) |
| Fair value of net trading assets as of December 31, 2001[(1)] | $ 1,337 |

(1) At December 31, 2001, net assets from non-trading price risk management activities were $23 million, and total net assets from all of our price risk management activities were $1,360 million.

The fair value of contracts settled during the period represents the amounts of traded contracts settled in cash, through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The initial recorded value of new contracts includes the fair value of origination transactions at the time the transaction is initiated. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination, until their settlement or, if not settled, until the end of the period. The cumulative effect of change in accounting principle includes the effect of our adoption of EITF Issues Topic D-105 in 2001. Included in other is the effect of natural gas storage purchases, premiums paid on option contracts and the values of contracts transferred to our trading portfolio as a result of a change in the manner in which these contracts were managed following the Coastal merger.

*Financial Services*

In the financial services area, Merchant Energy conducts energy financing activities through its ownership of EnCap and Enerplus. EnCap manages four separate oil and natural gas investment funds in the U.S., and serves as an investment advisor to one fund in Europe. EnCap also facilitates investment in emerging energy companies and earns a return from these investments. Enerplus, which was acquired in 2000, is a Canadian investment management company which conducts fund management activities similar to EnCap, but in Canada. Results from Merchant Energy's financial services activities are based on a combination of management fees and market based earnings on the investments held by these companies.

Below are Merchant Energy's operating results and an analysis of those results for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Trading gross margin | $ 675 | $ 403 | $ 103 |
| Operating and other revenues | 396 | 294 | 105 |
| Operating expenses | (483) | (264) | (299) |
| Other income | 313 | 130 | 94 |
| EBIT | $ 901 | $ 563 | $ 3 |
| Volumes (excludes intrasegment transactions): | | | |
| Physical | | | |
| Natural gas (BBtue/d) | 8,938 | 6,899 | 6,713 |
| Power (MMWh) | 220,668 | 116,749 | 79,361 |
| Other energy commodities (MBbls) | 19,444 | 7,772 | 4,990 |
| Financial Settlements (Bbtue/d) | 143,096 | 98,664 | 68,678 |

**Year Ended December 31, 2001 Compared to Year Ended December 31, 2000**

Trading gross margin consists of revenues from commodity trading and origination activities less costs of commodities sold. For the year ended December 31, 2001, these gross margins were $272 million higher than the same period in 2000. The increase was primarily due to higher trading margins in natural gas and power as a result of increased trading volumes and price volatility as well as increased income from transactions originated during 2001. The increase in trading margins was partially offset by reserves established as a result of the bankruptcy of Enron Corp. in December 2001.

Merchant Energy has conducted trading activities and held derivative positions with Enron Corp. and its subsidiaries. In December of 2001, Enron and certain of its subsidiaries sought protection from its creditors under Chapter 11 of the U.S. Bankruptcy Code. Following this filing, Merchant Energy terminated all contracts with the Enron subsidiaries that filed for bankruptcy. This resulted in the transfer of Merchant Energy's net derivative positions with Enron out of price risk management activities to accounts receivable. In addition, Merchant Energy established reserves on these receivables that it believes are adequate based on the amounts it expects to collect through the bankruptcy. In the first quarter of 2002, Merchant Energy asserted a claim against Enron on the cancelled contracts.

Merchant Energy is a provider of power and natural gas to the state of California. During the latter half of 2000 and continuing into the first half of 2001, California experienced sharp increases in wholesale power prices and natural gas prices due to energy shortages resulting, in part, from a combination of unusually warm summer weather followed by higher winter demand, low gas storage levels, lower hydroelectric power generation and maintenance downtime of significant generation facilities. As a result, the two major California utilities, Southern California Edison and Pacific Gas & Electric, defaulted on payments to creditors and accumulated substantial under-collections from customers. This resulted in their credit ratings being downgraded in 2001 from investment grade to below investment grade, and in April 2001, Pacific Gas & Electric filed for bankruptcy. During 2001, we recognized revenues from Pacific Gas & Electric and Southern California Edison that we believe are appropriate based on their improving financial condition. This resulted in our recognition of income on a portion of these transactions during the fourth quarter based on improved credit exposure to customers in the state.

Operating and other revenues consist of revenues from domestic and international power generation facilities and investments, including our management fee from Chaparral and revenues from EnCap and the other financial services businesses of Merchant Energy. For the year ended December 31, 2001, operating and other revenues were $102 million higher than the same period in 2000. The increase resulted from higher management fees from Chaparral, higher revenues from EnCap and our other financial services, and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001. Offsetting the increase were revenues recorded in 2000 on our West Georgia power generation facility that was sold in the fourth quarter of 2000.

Operating expenses for the year ended December 31, 2001, were $219 million higher than the same period in 2000. The increase was primarily a result of higher operating expenses resulting from the expansion of our operations in Europe, Mexico, Brazil, Singapore, our LNG business and the consolidation of the CEBU power project. This increase was partially offset by lower costs related to the West Georgia plant which was sold to Chaparral in the fourth quarter of 2000.

Other income for the year ended December 31, 2001, was $183 million higher than the same period in 2000. The increase was the result of marketing, agency and technical services fees related to the development of the Macaé power project in Brazil, and higher equity earnings from Chaparral resulting primarily from the completion of power contract restructurings. These increases were partially offset by lower earnings on an Argentine investment, and gains from the sale of a portion of our East Asia Power project occurring in the first quarter of 2000.

**Year Ended December 31, 2000 Compared to Year Ended December 31, 1999**

Trading gross margin for the year ended December 31, 2000, was $300 million higher than the same period in 1999. Trading margins increased due to significant price volatility in natural gas and power markets that increased the value of our trading portfolio during 2000 versus 1999. Also contributing to the increase was higher income from transactions originated in 2000.

Operating and other revenues for the year ended December 31, 2000, were $189 million higher than the same period in 1999. The increase was due to asset management fees earned from Chaparral, which began operations during the fourth quarter of 1999, revenues on the West Georgia power project, a seasonal peaking facility that began operating in June 2000, and the consolidation of a Brazilian power project in the latter part of 1999. Revenues on EnCap's financial services activities in 2000 also contributed to the increase.

Operating expenses for the year ended December 31, 2000, were $35 million lower than the same period in 1999. The decrease was due to higher reimbursement in 2000 of general and administrative costs relating to Chaparral, a 1999 charge to eliminate a minority investor in Sonat's marketing joint venture following the Sonat merger, and 1999 asset writedowns and charges to consolidate accounting policies with those of Sonat following the merger. These decreases were partially offset by higher general and administrative expenses and project development costs relating to international projects in 2000.

Other income for the year ended December 31, 2000, was $36 million higher than the same period in 1999. The increase was due to higher earnings from CE Generation, a power project acquired in March 1999 and the benefit realized from the formation of our East Asia Power joint venture in March 2000. These increases were partially offset by lower equity earnings from investments in various international projects, primarily our investment in East Asia Power in the Philippines.

## Field Services

Our Field Services segment provides a variety of services for the midstream component of our operations, including gathering and treating of natural gas, processing and fractionation of natural gas, natural gas liquids and natural gas derivative products, such as butane, ethane, and propane. In addition, Field Services owns 7 percent of El Paso Energy Partners, L.P.'s common units. A subsidiary of El Paso Corporation serves as the partnership's general partner.

Field Services attempts to balance its earnings from its operating activities through a combination of fixed-fee based and market-based services. A majority of Field Services gathering and treating operations earn margins from fixed-fee-based services. However, some of these operations earn margins from market-based rates. Revenues for these market-based rate services are the product of a market price, usually related to the monthly natural gas price index and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and to return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, Field Services may have more sensitivity to price changes during periods when natural gas and liquid prices are volatile.

In December 2000, Field Services completed the purchase of Pacific Gas & Electric's (PG&E's) Texas Midstream operations for $887 million, including $527 million of assumed debt. This acquisition was accounted for as a purchase. The assets acquired consist of 7,500 miles of intrastate natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing plants that process 1.5 Bcf/d and rights to 7.2 Bcf of natural gas storage capacity. These assets serve a majority of the metropolitan areas and the largest industrial load centers in Texas, as well as numerous natural gas trading hubs. Results from this acquisition are reflected in our results of operations from the date of purchase.

In March 2001, we sold some of the acquired natural gas liquids transportation and fractionation assets to El Paso Energy Partners for approximately $133 million. The assets sold included more than 600 miles of natural gas liquids gathering and transportation pipelines and three fractionation plants located in south Texas.

In February 2002, we announced the sale of additional midstream assets to El Paso Energy Partners for total consideration of $750 million. The primary assets to be sold include:

- 9,400 miles of intrastate transmission pipelines;
- 1,300 miles of gathering systems in the Permian Basin; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

Proceeds will be approximately $554 million in cash and approximately $6 million in El Paso Energy Partners common units, along with the partnership's interest in an offshore tension leg platform and a nine percent overriding royalty interest that the partnership holds in a producing field. These assets have a combined fair value estimated at approximately $190 million. We expect to complete the transaction in March 2002. The sale of these assets is contingent upon receiving customary regulatory approvals and execution of definitive agreements. We do not anticipate a material gain or loss on these transactions.

Field Services' operating results and an analysis of those results are as follows for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | (In millions except volumes and prices) | | |
| Gathering, treating and processing gross margin | $ 405 | $ 249 | $ 207 |
| Operating expenses | (326) | (165) | (161) |
| Other income | 2 | 4 | 32 |
| EBIT | $ 81 | $ 88 | $ 78 |
| Volume and prices | | | |
| Gathering and treating | | | |
| Volumes (BBtu/d) | 5,266 | 2,934 | 3,821 |
| Prices ($/MMBtu) | $ 0.13 | $ 0.17 | $ 0.14 |
| Processing | | | |
| Volumes (inlet BBtu/d) | 2,394 | 1,066 | 1,032 |
| Prices ($/MMBtu) | $ 0.16 | $ 0.18 | $ 0.12 |

**Year Ended December 31, 2001 Compared to Year Ended December 31, 2000**

Total gross margin for the year ended December 31, 2001, was $156 million higher than the same period in 2000. The increase was primarily due to higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Volumes also increased as a result of our acquisition of the Indian Basin processing plant in the second quarter of 2000 combined with an increase in Indian Basin's capacity in 2001. Also contributing to the increase were higher margins in the San Juan Basin due to higher natural gas liquids and natural gas prices in the first half of 2001 partially offset by lower prices in the second half of 2001. These increases were partially offset by higher processing costs associated with a new processing arrangement with El Paso Energy Partners at the Chaco processing facility in the fourth quarter of 2001. For the year ended December 31, 2001, average gathering, treating and processing rates were lower compared to 2000 due primarily to the different mix of assets and contract terms resulting from the acquisition of PG&E's Texas Midstream operations.

Operating expenses for the year ended December 31, 2001, were $161 million higher than the same period in 2000. The increase was a result of higher operating, depreciation and other expenses primarily from the addition of PG&E's Texas Midstream operations, increased general and administrative and merger-related costs. See a discussion of merger-related costs at Item 8, Financial Statements and Supplementary Data, Note 3.

**Year Ended December 31, 2000 Compared to Year Ended December 31, 1999**

Total gross margin for the year ended December 31, 2000, was $42 million higher than the same period in 1999. The increase was a result of higher average gathering rates, predominately in the San Juan Basin, which are substantially indexed to natural gas prices and higher average condensate prices. Also contributing to the increase were higher natural gas liquids prices in 2000 and our acquisition of the Indian Basin processing plant in the second quarter of 2000. The increase was partially offset by lower gathering and treating volumes due to the sale of El Paso Intrastate-Alabama, a gathering system in the coal-bed methane producing regions of Alabama, to El Paso Energy Partners in March 2000.

Operating expenses for the year ended December 31, 2000, were $4 million higher than the same period in 1999 due to higher depreciation and amortization from assets transferred from El Paso Natural Gas to Field Services following a FERC order as well as the December 2000 impairment charge related to the Needle Mountain LNG processing facility due to unrecoverability of costs. The increase was partially offset by the impairment of gathering assets in 1999, lower costs for labor and benefits and cost recoveries from managed facilities.

Other income for the year ended December 31, 2000, was $28 million lower than the same period in 1999. The decrease was primarily due to net gains in 1999 from the sale of our interest in the Viosca Knoll gathering system to El Paso Energy Partners in June 1999, as well as lower equity earnings in 2000 following the sale of our interest in Viosca Knoll.

**Interest and Debt Expense**

**Year Ended December 31, 2001 Compared to Year Ended December 31, 2000**

*Non-affiliated Interest and Debt Expense*

Non-affiliated interest and debt expense for the year ended December 31, 2001, was $7 million higher than 2000 due to long-term debt assumed by Field Services in relation to its acquisition of PG&E's Texas Midstream operations in December 2000.

*Affiliated Interest Expense*

Affiliated interest expense, net for the year ended December 31, 2001, was $33 million higher than 2000, primarily due to an increase in advances from El Paso for on-going capital projects, investment programs and operating requirements partially offset by lower short-term interest rates on average advances to El Paso under our cash management program with them.

**Year Ended December 31, 2000 Compared to Year Ended December 31, 1999**

*Non-affiliated Interest and Debt Expense*

Non-affiliated interest and debt expense for the year ended December 31, 2000, was $6 million higher than 1999 due to higher finance costs on international projects, higher Merchant Energy over-the-counter margins, and higher average commercial paper borrowings.

*Affiliated Interest Expense*

Affiliated interest expense for the year ended December 31, 2000, was $82 million higher than 1999 due to an increase in advances from El Paso for ongoing capital projects, investment programs, and operating requirements. The increase was also due to higher average interest rates with El Paso in 2000.

### Minority Interest

**Year Ended December 31, 2001 Compared to Year Ended December 31, 2000**

Minority interest for the year ended December 31, 2001, was $4 million higher than in 2000. This increase is due to higher balances in minority interest as a result of the issuance of preferred interests in Topaz Investors L.L.C. (part of our Gemstone transaction).

### Income Taxes

Income tax expense for the years ended December 31, 2001, 2000, and 1999 was $320 million, $242 million and $85 million. These amounts resulted in effective tax rates of 32 percent, 33 percent, and 31 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes;
- earnings from unconsolidated equity investees where we anticipate receiving dividends;
- foreign income taxed at different rates; and
- the non-deductible portion of merger-related costs.

For a reconciliation of the statutory rate of 35 percent to the effective tax rates, see Item 8, Financial Statements and Supplementary Data, Note 4.

## Liquidity and Capital Resources

### Cash From Operating Activities

Net cash provided by our operating activities was $2,487 million for the year ended December 31, 2001, compared to net cash used of $1,025 million for the same period of 2000. The increase was primarily due to physical liquidations of net derivative trading positions related to our price risk management activities, coupled with lower cash payments in 2001 for charges related to broker and over-the-counter margins.

### Cash From Investing Activities

Net cash used in our investing activities was $1,352 million for the year ended December 31, 2001. Our investing activities principally consisted of additions to property, plant and equipment primarily in our Merchant Energy and Pipelines Segments for expansion and construction projects. We had additions to joint ventures and investments in unconsolidated affiliates, primarily related to our investment in Gemstone, five coal-fired power plants and two international power companies located in Brazil and China. Our additions to investments also consist of short-term notes from unconsolidated affiliates related to East Coast Power which was repaid to us during the year. Our investing activities also included the buyout of Coastal's (our affiliate's) interest in El Paso Merchant Energy, L.P. for $114 million. In March 2001, we exchanged trading contracts and related assets with Coastal in exchange for units in our subsidiary, El Paso Merchant Energy, L.P. The exchange was based on the estimated fair value of the assets and units exchanged. Cash inflows from investment-related activities included proceeds from the sale of our Midwestern Gas Transmission system.

**Cash From Financing Activities**

Net cash used in our financing activities was $1,117 million for the year ended December 31, 2001. During 2001, we retired long-term debt, paid dividends and paid advances to El Paso. Cash provided from our financing activities included the issuance of preferred securities related to one of our consolidated subsidiaries associated with Gemstone and borrowings from commercial paper.

Our significant repayment activities during 2001 are presented below. These amounts do not include borrowings or repayments on our short-term financing instruments with an original maturity of three months or less, including our commercial paper program. We did not have significant borrowing activities during 2001.

| Date | Company | Type | Interest Rate | Principal (In millions) |
|---|---|---|---|---|
| *Retirements* | | | | |
| **2001** | | | | |
| February | El Paso Tennessee | Long-term debt | 9.875% | $ 24 |
| August | EPEC Corporation | Long-term debt | 9.625% | 13 |
| Jan.-Dec. | El Paso Field Services | Long-term debt | Various | 347 |

*Credit Facilities and Available Capacity*

We use a commercial paper program to manage our short-term cash requirements. TGP, our subsidiary, is eligible to borrow up to $1 billion under this program.

Our parent, El Paso, maintains a 3-year, $1 billion, revolving credit and competitive advance facility under which it can conduct short-term borrowings and other commercial credit transactions. This facility expires in 2003 and TGP is a designated borrower under the facility. In June 2001, El Paso replaced an existing 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. TGP is also a designated borrower under this new facility. The interest rate on these facilities varies and was based on LIBOR plus 50 basis points at December 31, 2001. No amounts were outstanding under these facilities at December 31, 2001.

As of December 31, 2001, TGP had $200 million under a shelf registration statement on file with the Securities and Exchange Commission.

The availability of borrowings under these credit and borrowing agreements is subject to specified conditions, which we believe are currently being met. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in such agreements.

*Future Liquidity*

We rely on cash generated from our internal operations and funding from our parent company as our primary sources of liquidity. We also supplement our internally generated cash through our commercial paper program and available credit facility. From time to time, we also use structured financial products. We expect that our future funding for working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt repayments, dividends and other financing activities will continue to be provided from these sources.

Our cash from internal operations may change in the future due to a number of factors, some of which we cannot control, including the price we will receive for the products we sell and services we provide, the demand for our products and services, margin requirements resulting from significant increases or decreases in commodity prices, operational risks, and other factors. Our ability to draw upon our available credit facilities will be dependent upon our ability and our parent company's ability to comply with the conditions and requirements of these credit facilities, all of which we believe are currently being met. Funding from the capital markets for commercial paper, long-term debt or equity or other structured financial products may be impacted by lack of liquidity for our industry segment, a change in our and our parent's credit rating or changes in market conditions.

## Contractual Obligations and Commercial Commitments

In the course of our business activities, we enter into a variety of contractual obligations and commercial commitments. Some of these result in direct obligations that are reflected in our balance sheet while others are commitments, some firm and some based on uncertainties, that are not reflected in our underlying financial statements.

### Contractual Cash Obligations

The following table summarizes our contractual cash obligations by payment due date. Each of these obligations is discussed in further detail below (in millions):

| | | Payments Due by Period | | | |
|---|---|---|---|---|---|
| Contractual Cash Obligations | Total | Less than 1 Year | 1-3 Years | 4-5 Years | After 5 Years |
| Short-term cash obligations | $ 499 | $ 499 | $ — | $ — | $ — |
| Long-term cash obligations[1] | 1,643 | 68 | 34 | 54 | 1,487 |
| Minority interests[2] | 356 | — | 300 | — | 56 |
| Operating leases | 24 | 7 | 6 | 4 | 7 |
| Capital commitments and purchase obligations | 1,627 | 500 | 148 | 163 | 816 |
| Total contractual cash obligations | $4,149 | $1,074 | $488 | $221 | $2,366 |

(1) Our long-term cash obligations exclude $12 million in unamortized debt discounts as of December 31, 2001.
(2) The maturity schedule for these instruments is based on the expiration period of the underlying agreements.

*Short-Term Cash Obligations*

Our short-term contractual cash obligations as of December 31, 2001, were as follows (in millions):

| | |
|---|---|
| Commercial paper | $424 |
| Notes payable | 75 |
| | $499 |

We can borrow up to $1 billion under a commercial paper program. At December 31, 2001, the weighted average rate on commercial paper outstanding was 3.2%.

We also have short-term notes payable to banks of $75 million.

*Long-Term Cash Obligations*

Our unsecured notes and debentures consists of third-party debt issued in the normal course of our business activities. These notes are secured by our general credit and that of our subsidiaries. The interest rates on these instruments range from 6.0% to 10.0%, and maturity dates range from 2002 to 2037. As of December 31, 2001, our total commitments under our long-term cash obligations were $1,643 million.

*Minority Interests*

Total amounts outstanding under minority interests at December 31, 2001, were as follows (in millions):

| | |
|---|---|
| Gemstone | $300 |
| Other | 56 |
| | $356 |

*Gemstone.* As part of the Gemstone transaction, our wholly owned subsidiary, Topaz Investors, L.L.C., issued a minority member interest to the third party investor of Gemstone for $300 million. The third party investor is entitled to a cumulative preferred return of 8.03% on its interest. The agreements underlying this transaction expire in 2004, or earlier if we sell the international power assets owned indirectly by Topaz. The minority member interest is redeemable at liquidation value plus accrued and unpaid dividends.

*Operating Leases*

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2002 until 2053. As of December 31, 2001, our total commitments under operating leases were approximately $24 million.

We have provided a residual value guaranty related to our Chaco plant lease. Under this guarantee, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is equal to the outstanding loan amount owed by the lessor, or we can choose to assist in the sale of the leased asset to a third party. Should the asset not be sold for a price that equals or exceeds the amount of the guaranty, we would be obligated for the shortfall. The levels of our residual value guaranty is 87 percent of the original cost of the leased asset. For the total outstanding residual value guaranty on our operating lease at December 31, 2001, see *Residual Value Guaranty* below.

*Capital Commitments and Purchase Obligations*

At December 31, 2001, we had capital and investment commitments of $1.5 billion primarily relating to our pipeline and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. We have entered into unconditional purchase obligations for products and services including financing commitments with one of our joint ventures, totaling $157 million at December 31, 2001. Our annual obligations under these agreements are $28 million for 2002, $25 million for 2003, $27 million for 2004 and 2005, $20 million for 2006 and $30 million in total thereafter.

**Commercial Commitments**

From May to October 2001, we entered into agreements to time-charter four separate ships to secure transportation for our developing liquefied natural gas business. The agreements provide for deliveries of vessels between 2003 and 2005. Each time-charter has a 20-year term commencing when the vessels are delivered with the possibility of two 5-year extensions. The total commitment under the four time charter agreements is $1.8 billion. We do not have any commitments under these agreements until 2003. Our annual commitments under these agreements are $7 million in 2003, $37 million in 2004, $72 million in 2005, $89 million in 2006 and $1,574 million in total thereafter.

*Residual Value Guaranty*

As of December 31, 2001, we had a residual value guaranty related to an operating lease of $77 million. The lease expires in 2002.

## Contingencies

For a discussion of our contingencies, see Item 8, Financial Statements and Supplementary Data, Note 10, incorporated herein by reference.

## Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by analogizing to similar situations and the accounting guidance governing them, and often consult with our independent accountants about the appropriate interpretation and application of these policies. Our critical accounting policies include policies such as accounting for price risk management activities, accounting for impairments, accounting for reserves and consolidation policies. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

*Critical Accounting Policies*

*Price Risk Management Activities.* We account for price risk management activities based upon the fair value accounting methods prescribed by Emerging Issues Task Force (EITF) Issue 98-10 and SFAS No. 133. EITF Issue 98-10 governs the accounting for our energy trading activities while SFAS No. 133 prescribes our accounting for hedging activities and other derivatives. Both sets of accounting rules require that we determine the fair value of the instruments we use in our business activities and reflect them in our balance sheet at their fair values. However, changes in the fair value from period to period for our energy trading derivatives and fair value hedges are recorded in our income statement each period while changes in the fair value of our cash flow hedges are generally recognized in our income statement when the hedge is settled. Over time, these two methods will derive similar results. However, from period to period, income under these methods can differ significantly.

One of the primary factors that can have an impact on our results each period is the price assumptions used to value our energy trading derivatives and fair value hedges. Many of these instruments have quoted market prices. However, we are required to use internal valuation techniques or models, particularly in our energy trading activities, to estimate the fair value of instruments that are not traded on an active exchange or that have terms that extend beyond the time period for which exchange-based quotes are available. These modeling techniques require us to estimate future prices, price correlation, interest rates and market volatility and liquidity. Our estimates also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instrument and the transaction being hedged, both at the inception and on an on-going basis. This is complicated since energy commodity prices, the primary risk we hedge, have quality and locational differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond of our control.

*Asset Impairments.* The asset impairment accounting rules require us to determine if an event has occurred indicating that a long-lived asset may be impaired. In some cases, these events are clear. However, in many cases, a clearly identifiable triggering event does not occur. Rather, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated where we have investments in foreign countries or where we have projects where we are not the operator. Events can occur that may not be known until a later date from their occurrence. We continually monitor our businesses and the market and business environments and make judgments and assessments about whether a triggering event has occurred. If an event occurs, we make an estimate of our future cash flows from these assets to determine if the asset is impaired. For investments, we evaluate whether events and possible outcomes indicate that a decline in the value of our investment that is other than temporary has occurred, which also generally involves an assessment of project level cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our estimates of impairment and can result in additional charges. In addition, further changes in the economic and business environment can impact our original and ongoing assessments of potential impairment.

*Accounting for Reserves.* Our accounting policies for reserves cover a wide variety of business activities, including reserves for potentially uncollectible receivables, rate matters and legal and environmental exposures. We accrue these reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Our estimates for these liabilities are based on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon the outcome or expectations based on the facts surrounding each exposure.

*Principles of Consolidation.* We currently have interests in joint ventures, equity investments and financing arrangements that, based on existing accounting guidance, we are precluded from consolidating. In December 2001, Enron Corp., one of the largest companies in the energy industry, declared bankruptcy in what has been viewed as one of the largest bankruptcies in history. In the wake of this event, accounting standard setters, including the Securities and Exchange Commission, are evaluating the existing accounting and disclosure rules and requirements. One area that has received a high level of scrutiny is the accounting rules related to consolidations, specifically those that address special-purpose entities. Standard setting bodies and regulators are currently evaluating the consolidation rules to determine whether the existing accounting framework should change. In the future, there is risk that existing standards will change, particularly in light of the events of 2001, and that these changes could result in the consolidation in our financial statements of entities that we do not currently consolidate.

For further details on these and our other significant accounting policies, and the estimates, assumptions and judgments we use in applying these policies, see Item 8, Financial Statements and Supplementary Data, Note 1.

*New Accounting Policies Issued But not Yet Adopted*

*Business Combinations.* In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations.* This Statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This Statement also establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off at the acquisition date as an extraordinary item. The accounting for any business combinations we undertake in the future will be impacted by this standard. The Statement also requires, upon adoption, that we write off to income any negative goodwill recognized on business combinations for which the acquisition date was before July 1, 2001, as the effect of a change in accounting principle. We do not expect the negative goodwill provisions of this pronouncement will have a material effect on our financial statements.

*Goodwill and Other Intangible Assets.* In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets.* This Statement requires that goodwill no longer be amortized but periodically tested for impairment at least on an annual basis. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This Statement has various effective dates, the most significant of which is January 1, 2002. Upon adoption of this Statement on January 1, 2002, we will no longer recognize annual amortization expense of approximately $15 million on goodwill and indefinite-lived intangible assets. We do not expect the impairment provisions of this pronouncement will have a material effect on our financial statements.

*Accounting for Asset Retirement Obligations.* In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This Statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

*Accounting for the Impairment or Disposal of Long-Lived Assets.* In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* This Statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this Statement are effective for fiscal years beginning after December 15, 2001. The provisions of this Statement will impact any asset dispositions we make after January 1, 2002, including the announced sale of midstream assets to El Paso Energy Partners.

*Derivatives Implementation Group Issue C-16.* In September 2001, the Derivatives Implementation Group of the FASB cleared guidance on Issue C-16, *Scope Exceptions: Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract.* This guidance impacts the accounting for fuel supply contracts that require delivery of a contractual minimum quantity of a fuel other than electricity at a fixed price and have an option that permits the holder to take specified additional amounts of fuel at the same fixed price at various times. We use fuel supply contracts such as these in our power producing operations and currently do not reflect them in our balance sheet since they are considered normal purchases that are not classified as derivative instruments under SFAS No. 133. This guidance becomes effective in the second quarter of 2002, and we will be required to account for these contracts as derivative instruments under SFAS No. 133. We are currently evaluating the impact of this guidance on our financial statements.

## CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. All of our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We use derivative financial instruments to manage market risks associated with energy commodities, interest rates and foreign currency exchange rates. Our primary market risk exposures are to changing commodity prices. Our market risks are monitored by a risk management committee to ensure compliance with El Paso's overall stated risk management policies as approved by the Audit Committee of El Paso's Board of Directors. This risk management committee operates independently from the business segments that create or actively manage these risk exposures.

During 2001, we experienced a significantly changing energy market brought about by the energy crisis in California, the events of September 11th, the bankruptcy of Enron Corp., and a significant decline in energy commodity prices. We limited our market risk exposure during this period of market uncertainty by continually monitoring our net physical and financial positions and assuming minimal risk. We expect this continuous monitoring and reduced risk assumption to continue in the near term.

### Commodity Price Risk

*Trading Price Risk*

Our Merchant Energy segment is exposed to market risks inherent in the financial instruments it uses for trading energy and energy related commodities. Merchant Energy records its energy trading activities, including transportation capacity, tolling agreements and storage contracts at fair value. Changes in fair value of these activities are reflected in our income statement. Merchant Energy's policy is to manage commodity price risks through a variety of financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity;
- exchange-traded and over-the-counter options; and
- other contractual arrangements.

*Non-Trading Price Risk*

Our segments are exposed to a variety of market risks in the normal course of their business activities. Our Field Services segment has market risks related to the natural gas and natural gas liquids it retains in its processing operations. Our Merchant Energy segment has market risks from changing prices of natural gas between locations on capacity it holds on our pipelines. We attempt to mitigate market risk associated with these significant physical transactions through the use of non-trading financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity; and
- exchange-traded and over-the-counter options.

*Price Risk Management*

Merchant Energy measures the risk in its trading and non-trading commodity and energy related contracts on a daily basis using a Value-at-Risk model to determine the maximum potential one-day unfavorable impact on its earnings, due to normal market movements, and monitors its risk in comparison to established thresholds. Since 1998, Merchant Energy has used what is known as the variance-covariance technique of measuring Value-at-Risk. This technique uses historical price movements and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of its assets and liabilities held for price risk management activities. This method works well for futures, forwards, and swaps, but does not completely capture the risk of option positions, especially for large deviations from current underlying values. For this reason, Merchant Energy began measuring its Value-at-Risk using a historical simulation technique in December 2001. This technique fully values positions in every iteration of the simulation and captures risk from all types of positions, including options. Merchant Energy also uses other measures to provide additional assurance that the risks in its commodity and energy related contracts are being properly monitored on a daily basis, including sensitivity analysis, stress testing, credit risk management and the establishment of parameters to monitor and measure risk exposure, highlight unfavorable trends, and measure performance of the portfolio using applicable risk metrics.

The following table presents our potential one-day unfavorable impact on earnings before interest and income taxes as measured by Value-at-Risk for our trading and non-trading commodity and energy related contracts and is prepared based on a confidence level of 95 percent and a one-day holding period. The high and low valuations represent the highest and lowest of the month and values during 2001. The average valuation represents the average of the 2001 month end values. Actual losses may exceed those measured by Value-at-Risk using either of the modeling techniques presented below:

| | Value-at-Risk | | | | |
|---|---|---|---|---|---|
| | 2001 | | | | 2000 |
| Value-at-Risk Modeling Technique | Year End | High | Low | Average | Year End |
| | (In millions) | | | | |
| Trading Value-at-Risk | | | | | |
| Variance-covariance | $21 | $45 | $21 | $33 | $29 |
| Historical simulation | $18 | | | | |
| Non-Trading Value-at-Risk | | | | | |
| Variance-covariance | $ 5 | $15 | $ 3 | $ 8 | — |
| Historical simulation | $ 7 | | | | |
| Portfolio Value-at-Risk(1) | | | | | |
| Historical simulation | $14 | | | | |

(1) Portfolio Value-at-Risk represents the combined Value-at-Risk for the trading and non-trading price risk management activities. The separate calculation of Value-at-Risk for trading and non-trading commodity contracts ignores the natural correlation that exists between traded and non-traded commodity contracts and prices. As a result, the individually determined values will be higher than the combined Value-at-Risk in most instances. We manage our risks through a portfolio approach that balances both trading and non-trading risks.

### Interest Rate Risk

Many of our debt-related financial instruments, derivative contracts and project financing arrangements are sensitive to market fluctuations in interest rates. From time to time, we manage our exposure to interest rate risk through the use of non-trading derivative financial instruments, primarily through interest rate swaps.

The table below shows the maturity of the carrying amounts and related weighted average interest rates of our interest bearing securities, by expected maturity dates. As of December 31, 2001, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term debt has been estimated based on quoted market prices for the same or similar issues.

| | December 31, 2001 | | | | | | | | December 31, 2000 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Expected Fiscal Year of Maturity of Carrying Amounts | | | | | | | | | |
| | 2002 | 2003 | 2004 | 2005 | 2006 | Thereafter | Total | Fair Value | Carrying Amounts | Fair Value |
| | (Dollars in millions) | | | | | | | | | |
| **Liabilities:** | | | | | | | | | | |
| Short-term debt — variable rate | $499 | | | | | | $ 499 | $ 499 | $ 302 | $ 302 |
| Average interest rate | 3.0% | | | | | | | | | |
| Long-term debt, including current portion — fixed rate | $ 65 | | $ 31 | $ 54 | | $1,452 | $1,602 | $1,563 | $1,977 | $2,004 |
| Average interest rate | 8.7% | | 8.9% | 9.1% | | 7.5% | | | | |
| Long-term debt, including current portion — variable rate | $ 3 | $ 3 | $ 3 | $ 3 | $ 3 | $ 14 | $ 29 | $ 29 | $ — | $ — |
| Average interest rate | 6.3% | 4.9% | 5.8% | 6.1% | 6.3% | 6.3% | | | | |

### Foreign Currency Exchange Rate Risk

Our exposure to foreign currency exchange rates relates to changes in foreign currency rates on our international power investments and operations, our foreign trading operations and foreign debt obligations that are not denominated or adjusted to U.S. dollars. From time to time, we manage this exposure to changes in foreign currency exchange rates by entering into derivative financial instruments, principally foreign currency forward purchase and sale contracts. The following table summarizes the notional amounts, average settlement rates, and fair value for foreign currency forward purchase and sale contracts as of December 31, 2001:

| | | Notional Amount in Foreign Currency (In millions) | Average Settlement Rates | Fair Value in U.S. Dollars (In millions) |
|---|---|---|---|---|
| Canadian Dollars | Purchase | 401 | .653 | $(18) |
| | Sell | 291 | .680 | 17 |
| | | | | $ (1) |

The following table summarizes foreign currency forward purchase and sale contracts by expected maturity dates along with annual anticipated cash flow impacts as of December 31, 2001:

| | | Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2002 | 2003 | 2004 | 2005 | 2006 | Thereafter | Total |
| | | (In millions) | | | | | | |
| Canadian Dollars | Purchase | $(11) | $(6) | $(2) | $ — | $ — | $ 1 | $(18) |
| | Sell | 10 | 5 | 2 | — | — | — | 17 |
| | Net cash flow effect | $ (1) | $(1) | $— | $ — | $ — | $ 1 | $ (1) |

### Equity Risk

Our Merchant Energy Segment holds investments that expose us to price risk associated with equity securities markets. We account for these investments using investment company accounting. As a result, these holdings are measured at their fair value with changes in fair value recorded in our income statement. The fair value of these investments are determined based on estimates of amounts that would be realized if these securities were sold. Below are the fair values of these holdings at December 31, 2001 and 2000, as well as the impact of a ten percent increase or decrease in the underlying fair values of these securities for each period presented:

| | 2001 | | | 2000 | | |
|---|---|---|---|---|---|---|
| | Fair Value | Impact of 10 Percent Increase | Impact of 10 Percent Decrease | Fair Value | Impact of 10 Percent Increase | Impact of 10 Percent Decrease |
| | (in millions) | | | | | |
| Investment funds | $13 | $ 1 | $(1) | $ 7 | $ 1 | $(1) |
| Securities | 15 | 2 | (2) | 54 | 5 | (5) |
| Other | — | — | — | 1 | — | — |
| Total | $28 | $ 3 | $(3) | $62 | $ 6 | $(6) |

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### EL PASO TENNESSEE PIPELINE CO.

### CONSOLIDATED STATEMENTS OF INCOME
**(In millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| Operating revenues | $32,982 | $20,788 | $9,670 |
| Operating expenses | | | |
| Cost of natural gas and other products | 30,791 | 19,076 | 8,411 |
| Operation and maintenance | 789 | 576 | 577 |
| Merger-related costs and asset impairments | 108 | 11 | 75 |
| Depreciation, depletion and amortization | 254 | 223 | 247 |
| Taxes, other than income taxes | 79 | 62 | 62 |
| | 32,021 | 19,948 | 9,372 |
| Operating income | 961 | 840 | 298 |
| Other income | | | |
| Earnings from unconsolidated affiliates | 197 | 61 | 61 |
| Net gain on sale of assets | — | 24 | 24 |
| Other, net | 139 | 63 | 64 |
| | 336 | 148 | 149 |
| Income before interest, income taxes and other charges | 1,297 | 988 | 447 |
| Non-affiliated interest and debt expense | 149 | 142 | 136 |
| Affiliated interest expense, net | 155 | 122 | 40 |
| Minority interest | 4 | — | — |
| Income taxes | 320 | 242 | 85 |
| | 628 | 506 | 261 |
| Income before extraordinary items and cumulative effect of accounting change | 669 | 482 | 186 |
| Extraordinary items, net of income taxes | 38 | 58 | — |
| Cumulative effect of accounting change, net of income taxes | 10 | — | (13) |
| Net income | $ 717 | $ 540 | $ 173 |

See accompanying notes.

## EL PASO TENNESSEE PIPELINE CO.

## CONSOLIDATED BALANCE SHEETS
**(In millions, except share amounts)**

| | December 31, 2001 | December 31, 2000 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 197 | $ 179 |
| Accounts and notes receivable, net of allowance of $223 in 2001 and $100 in 2000 | | |
| Customer | 2,723 | 2,829 |
| Affiliates | 271 | 194 |
| Other | 600 | 262 |
| Inventory | 79 | 84 |
| Assets from price risk management activities | 2,529 | 4,283 |
| Margin deposits on energy trading activities | 379 | 377 |
| Other | 318 | 205 |
| Total current assets | 7,096 | 8,413 |
| Property, plant and equipment, at cost | | |
| Pipelines | 2,824 | 2,554 |
| Power facilities | 563 | 351 |
| Gathering and processing systems | 2,199 | 2,543 |
| Other | 99 | 96 |
| | 5,685 | 5,544 |
| Less accumulated depreciation, depletion and amortization | 1,040 | 843 |
| | 4,645 | 4,701 |
| Additional acquisition costs assigned to utility plant, net of accumulated amortization | 2,271 | 2,287 |
| Property, plant and equipment, net | 6,916 | 6,988 |
| Investments in unconsolidated affiliates | 2,825 | 2,008 |
| Assets from price risk management activities | 2,156 | 1,638 |
| Other | 1,002 | 418 |
| Total assets | $19,995 | $19,465 |

See accompanying notes.

**EL PASO TENNESSEE PIPELINE CO.**

**CONSOLIDATED BALANCE SHEETS — (Continued)**
**(In millions, except share amounts)**

| | December 31, 2001 | December 31, 2000 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts and notes payable | | |
| Trade | $ 2,927 | $ 3,156 |
| Affiliates | 2,932 | 3,760 |
| Other | 308 | 102 |
| Short-term borrowings | 567 | 434 |
| Liabilities from price risk management activities | 2,089 | 2,880 |
| Margin deposits from customers on energy trading activities | 649 | 353 |
| Other | 557 | 347 |
| Total current liabilities | 10,029 | 11,032 |
| Long-term debt | 1,563 | 1,845 |
| Deferred credits and other | | |
| Deferred income taxes | 1,971 | 1,647 |
| Liabilities from price risk management activities | 1,236 | 898 |
| Other | 996 | 838 |
| | 4,203 | 3,383 |
| Commitments and contingencies | | |
| Minority interest | 356 | 51 |
| Stockholders' equity | | |
| Preferred stock, 20,000,000 shares authorized; Series A, no par; 6,000,000 shares issued; stated at liquidation value | 300 | 300 |
| Common stock, par value $0.01 per share; authorized 100,000 shares; issued 1,971 shares | — | — |
| Additional paid-in capital | 1,973 | 1,962 |
| Retained earnings | 1,641 | 949 |
| Accumulated other comprehensive income | (70) | (57) |
| Total stockholders' equity | 3,844 | 3,154 |
| Total liabilities and stockholders' equity | $19,995 | $19,465 |

See accompanying notes.

## EL PASO TENNESSEE PIPELINE CO.

## CONSOLIDATED STATEMENTS OF CASH FLOWS
**(In millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2001** | **2000** | **1999** |
| Cash flows from operating activities | | | |
| Net income | $ 717 | $ 540 | $ 173 |
| Adjustments to reconcile net income to net cash from operating activities | | | |
| Depreciation, depletion and amortization | 254 | 223 | 247 |
| Deferred income tax expense | 309 | 207 | 69 |
| Net gain on the sale of assets | — | (24) | (24) |
| Extraordinary items | (59) | (99) | — |
| Undistributed earnings of unconsolidated affiliates | (55) | (21) | (30) |
| Non-cash portion of merger-related costs and asset impairments | 73 | 11 | 75 |
| Non-cash portion of price risk management activities | (877) | (443) | (281) |
| Cumulative effect of accounting changes | (17) | — | 13 |
| Other | (8) | — | — |
| Working capital changes, net of non-cash transactions | | | |
| Accounts and notes receivable | 1,047 | (2,081) | (35) |
| Accounts payable/receivable with affiliates | 431 | 9 | (41) |
| Inventory | 28 | (8) | (3) |
| Change in trading price risk management activities, net | 1,565 | (1,373) | 103 |
| Accounts payable | (1,246) | 1,982 | 114 |
| Change in margin deposits from customers on energy trading activities | 296 | 351 | 2 |
| Other working capital changes | 136 | (269) | (88) |
| Non-working capital changes and other | (107) | (30) | 31 |
| Net cash provided by (used in) operating activities | 2,487 | (1,025) | 325 |
| Cash flows from investing activities | | | |
| Additions to property, plant and equipment | (608) | (471) | (458) |
| Additions to investments | (1,002) | (794) | (796) |
| Cash paid for acquisitions, net of cash acquired | (118) | (368) | (165) |
| Net proceeds from the sale of assets | 109 | 650 | 31 |
| Proceeds from the sale of investments | 11 | 122 | 33 |
| Change in cash deposited in escrow related to an equity investee | 3 | 24 | (101) |
| Repayment of notes receivable from unconsolidated affiliates | 242 | — | — |
| Other | 11 | (15) | — |
| Net cash used in investing activities | (1,352) | (852) | (1,456) |
| Cash flows from financing activities | | | |
| Net borrowings (repayments) of commercial paper | 209 | (434) | 459 |
| Payments to retire long-term debt | (384) | (8) | (4) |
| Dividends paid | (25) | (25) | (25) |
| Net proceeds from the issuance of notes payable | — | 58 | 101 |
| Repayment of notes payable | (3) | (82) | — |
| Increase (decrease) in notes to unconsolidated affiliates | (9) | 9 | — |
| Net proceeds from issuance of minority interests in subsidiaries | 281 | — | — |
| Net change in other affiliated advances payable | (1,186) | 2,306 | 496 |
| Capital contributions | — | 200 | 108 |
| Net cash provided by (used in) financing activities | (1,117) | 2,024 | 1,135 |
| Increase in cash and cash equivalents | 18 | 147 | 4 |
| Cash and cash equivalents | | | |
| Beginning of period | 179 | 32 | 28 |
| End of period | $ 197 | $ 179 | $ 32 |

See accompanying notes.

## EL PASO TENNESSEE PIPELINE CO.

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
**(In millions)**

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2001 | | 2000 | | 1999 | |
| | Shares | Amount | Shares | Amount | Shares | Amount |
| Series A Preferred Stock | 6 | $ 300 | 6 | $ 300 | 6 | $ 300 |
| Common stock | — | — | — | — | — | — |
| Additional paid-in capital | | | | | | |
| Balance at beginning of year | | 1,962 | | 1,707 | | 1,580 |
| Capital contributions | | — | | 233 | | 120 |
| Allocated tax benefit of El Paso's equity plans | | 9 | | 22 | | 7 |
| Proceeds from Encap earnout | | 2 | | — | | — |
| Balance at end of year | | 1,973 | | 1,962 | | 1,707 |
| Retained earnings | | | | | | |
| Balance at beginning of year | | 949 | | 451 | | 306 |
| Net income | | 717 | | 540 | | 173 |
| Dividends to parent | | — | | (18) | | (1) |
| Preferred dividends | | (25) | | (25) | | (25) |
| Other | | — | | 1 | | (2) |
| Balance at end of year | | 1,641 | | 949 | | 451 |
| Accumulated other comprehensive income | | | | | | |
| Balance at beginning of year | | (57) | | (28) | | (14) |
| Other comprehensive income | | (13) | | (29) | | (14) |
| Balance at end of year | | (70) | | (57) | | (28) |
| Total stockholders' equity | 6 | $3,844 | 6 | $3,154 | 6 | $2,430 |

See accompanying notes.

## EL PASO TENNESSEE PIPELINE COMPANY

## CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
**(In millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| **Comprehensive Income** | **2001** | **2000** | **1999** |
| Net income | $ 717 | $540 | $173 |
| Foreign currency translation adjustments | (3) | (29) | (14) |
| Unrealized net gains (losses) from cash flow hedging activity | | | |
| Cumulative-effect transition adjustment (net of tax of $66) | (154) | — | — |
| Reclassification of initial cumulative-effect transition adjustment at original value (net of tax of $66) | 132 | — | — |
| Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $45) | 60 | — | — |
| Unrealized mark-to-market losses arising during period (net of tax of $38) | (48) | — | — |
| Other comprehensive income | (13) | (29) | (14) |
| Comprehensive income | $ 704 | $511 | $159 |

| | | | |
|---|---|---|---|
| **Accumulated Other Comprehensive Income** | **2001** | **2000** | **1999** |
| Beginning balances as of January 1 | $ (57) | $(28) | $(14) |
| Foreign currency translation adjustments | (3) | (29) | (14) |
| Unrealized net (losses) from cash flow hedging activity | | | |
| Cumulative-effect transition adjustment, net of taxes | (154) | — | — |
| Reclassification of initial cumulative-effect transition adjustment at original value, (net of taxes) | 132 | — | — |
| Additional reclassification adjustments for changes in initial value to settlement date, net of taxes | 60 | — | — |
| Unrealized mark-to-market losses arising during period net of taxes | (48) | — | — |
| Balance as of December 31, | $ (70) | $(57) | $(28) |

See accompanying notes.

## EL PASO TENNESSEE PIPELINE CO.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Summary of Significant Accounting Policies

*Basis of Presentation*

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholders' equity.

*Principles of Consolidation*

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity.

*Use of Estimates*

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues, and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

*Accounting for Regulated Operations*

Our interstate natural gas systems and storage operations are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Our regulated operations apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*. Accounting for businesses that are regulated and apply the provisions of SFAS No. 71 can differ from the accounting requirements for non-regulated businesses. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, employee related benefits, and other costs and taxes included in, or expected to be included in, future rates.

We will continue to evaluate the application of regulatory accounting principles as there are on-going changes in the regulatory and economic environment. Things that may influence this assessment are:

- inability to recover cost increases due to rate caps and rate case moratoriums;
- inability to recover capitalized costs, including an adequate return on those costs through the ratemaking process;
- excess capacity;
- discounting rates in the markets we serve; and
- impacts of ongoing initiatives in, and deregulation of, the natural gas industry.

*Cash and Cash Equivalents*

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

*Allowance for Doubtful Accounts*

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

*Inventory*

Our inventory consists of materials and supplies and natural gas in storage for non-trading purposes. We value all inventory at the lower of cost or market with cost determined using the average cost method.

*Natural Gas Imbalances*

Natural gas imbalances occur when the actual amount of natural gas delivered from or received by a pipeline system, processing plant or storage facility differs from the contractual amount scheduled to be delivered or received. We value these gas imbalances due to or from shippers and operators at an appropriate market index price based on when we expect to settle the imbalance. Imbalances are settled in cash or made up in-kind, subject to the contractual terms of settlement.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to affiliates. In addition, all imbalances are classified as current or long-term depending on when we expect to settle them.

*Property, Plant and Equipment*

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. We capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates.

The following table presents our property, plant and equipment by type, depreciation method, remaining useful lives and depreciation rate:

| Type | Method | Remaining Useful Lives | Rates |
|---|---|---|---|
| | | (In years) | |
| Regulated systems[(1)] | Composite | 2-33 | 1% to 24% |
| Non-regulated systems | | | |
| Gathering and processing systems | Straight-line | 1-40 | 3% to 40% |
| Power facilities | Straight-line | 1-49 | 2% to 33% |
| Transportation equipment | Straight-line | 1-5 | 20% to 33% |
| Buildings and improvements | Straight-line | 1-40 | 3% to 20% |
| Office and miscellaneous equipment | Straight-line | 1-10 | 10% to 50% |

(1) We use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff, to the total cost of the group, until its net book value equals its salvage value. We reevaluate depreciation rates each time we redevelop our transportation rates when we file with FERC for an increase or decrease in rates.

When we retire regulated property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost of retirement (the cost to remove, sell or dispose), less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income. When we retire non-regulated properties, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage. Any remaining gain or loss is recorded in income.

At December 31, 2001 and 2000, we had approximately $347 million and $343 million of construction work in progress included in our property, plant and equipment.

*Asset Impairments*

We evaluate our long-lived assets for impairments in accordance with SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.* If an adverse event or change in circumstances occurs, we estimate the future cash flows from the asset, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to sales data for similar assets, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, prices, operating costs, legal, regulatory and other factors, and these assumptions can change either positively or negatively.

*Intangible Assets*

Intangible assets consist primarily of goodwill arising as a result of mergers and acquisitions. We amortize these intangible assets using the straight-line method over periods ranging from 5 to 40 years. We evaluate impairment of goodwill in accordance with APB No. 17, *Intangible Assets,* as amended by SFAS No. 121. Under this methodology, when an event occurs that suggests that an impairment may have occurred, we evaluate the undiscounted net cash flows of the asset or entity to which the goodwill relates. If these cash flows are not sufficient to recover the value of the asset or entity plus its related goodwill, these cash flows are discounted at a risk-adjusted rate with any difference recorded as a change in our income statement.

*Revenue Recognition*

Our regulated businesses recognize revenues from natural gas transportation services and services other than transportation in the period when the service is provided. In the future, we will record reserves on revenues collected that may be subject to refund.

Our non-regulated businesses record revenues when they are earned. Revenues are earned when deliveries of physical commodities are made, or when services are provided. See the discussion of price risk management activities below for our revenue recognition policies on our trading activities.

*Environmental Costs and Other Contingencies*

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods by preventing or eliminating future contamination. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage, government sponsored and other programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

*Price Risk Management Activities*

We engage in price risk management activities for both trading and non-trading purposes to manage market risks associated with commodities we purchase and sell, interest rates and foreign currency exchange rates.

Our trading and non-trading price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded futures contracts that involve cash settlements;
- forward contracts involving cash settlements or physical delivery of a commodity;
- swap contracts, which require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices for a commodity; and
- exchange-traded and over-the-counter options.

*Trading Activities.* Our trading activities include the services we provide in the energy sector, primarily related to the purchase and sale of energy commodities. We account for our trading activities at their fair market value under the requirements of Emerging Issues Task Force (EITF) Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. In addition to the derivatives above, our trading activities also include non-derivative instruments such as transportation and storage capacity contracts, and physical natural gas that is actively traded. We reflect the market values of our trading activities in our balance sheet as price risk management activities. These are classified as current or long-term based on their anticipated settlement date. In our income statement, we account for physical settlements that result in delivery of a commodity as revenues or cost of products sold based on whether we buy or sell the commodity. Financial settlements as well as changes in the market value of traded positions are included in revenue.

*Non-trading Activities.* Our non-trading price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures on our assets, liabilities, contractual commitments and forecasted transactions related to our gas transmission, power generation, financing and international business activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, in accounting for our non-trading derivative instruments. Under SFAS No. 133, all derivatives are reflected in our balance sheet at their fair market value. We do not apply the mark-to-market method of accounting for contracts that qualify as normal purchases and sales under SFAS No. 133.

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or a firm commitment. On the date that we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments.

As required by SFAS No. 133, we formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge.

The market value of both trading and non-trading instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize our valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. Our actual results may differ from our estimates, and these differences can be positive or negative.

Cash inflows and outflows associated with the settlement of both trading and non-trading price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported separately from price risk management activities in our balance sheet as trade receivables and payables.

Prior to our adoption of SFAS No. 133, we applied hedge accounting for our non-trading derivatives only if the derivative reduced the risk of the underlying hedged item, was designated as a hedge at its inception and was expected to result in financial impacts which were inversely correlated to those of the item being hedged. If correlation ceased to exist, hedge accounting was terminated and the derivatives were recorded at their fair value in the balance sheet and changes in fair value were recorded in income. Changes in the market value of derivatives designated as hedges were deferred as deferred revenue or expense until the gain or loss was recognized on the hedged transaction. Derivatives held for non-trading purposes were recorded as gains or losses in operating income and cash inflows and outflows were recognized in operating cash flow as the settlement of those transactions occurred.

*Income Taxes*

We report current income taxes based on our taxable income along with a provision for deferred income taxes. Deferred income taxes reflect the estimated future tax consequences of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

El Paso maintains a tax sharing policy for companies included in its consolidated federal income tax return which provides, among other things, that (i) each company in a taxable income position will be currently charged with an amount equivalent to its federal income tax computed on a separate return basis, and (ii) each company in a tax loss position will be reimbursed currently to the extent its deductions, including general business credits, were utilized in the consolidated return. Under the policy, El Paso pays all federal income taxes directly to the IRS and bills or refunds its subsidiaries, including us, for their portion of these income tax payments.

*Foreign Currency Transactions and Translation*

We record all currency transaction gains and losses in income. The net currency transaction loss recorded to income in 2001 was $10 million and was insignificant in 2000. The U.S. dollar is the functional currency for substantially all of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and included as a separate component of comprehensive income and stockholders' equity. The cumulative currency translation loss recorded in accumulated other comprehensive income was $60 million and $57 million at December 31, 2001 and 2000. Revenues and expenses are translated at average exchange rates prevailing during the year.

*Cumulative Effect of Accounting Change*

In November 2001, the Financial Accounting Standards Board (FASB) issued EITF Issues Topic D-105 (D-105), *Accounting in Consolidation for Energy Trading Contracts between Affiliated Entities When the Activities of One but Not Both Affiliates Are within the Scope of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities".* This announcement requires all energy trading transactions, and any related mark-to-market gains and losses, between entities of the same consolidated group to be eliminated in consolidated financial statements. It also requires energy trading transactions with these affiliated companies to be reflected in the stand-alone financial statements of the energy-trading entities involved in these transactions. We adopted the announcement effective December 31, 2001, and reported a gain of $10 million, net of income taxes of $7 million, related to our contracts with non-EITF Issue No. 98-10 affiliates. We recorded this amount as a cumulative effect of an accounting change in accordance with the transition provisions of D-105.

In April 1998, the American Institute of Certified Public Accountants issued Statement of Position 98-5, *Reporting on the Costs of Start-Up Activities.* The statement defined start-up activities and required start-up and organization costs be expensed as incurred. In addition, it required that any such cost that existed on the balance sheet be expensed upon adoption of the pronouncement. We adopted the pronouncement effective January 1, 1999, and reported a charge of $13 million, net of income taxes, as a cumulative effect of accounting change.

*New Accounting Pronouncements Issued But Not Yet Adopted*

During 2001, the Financial Accounting Standards Board issued SFAS No. 141, *Business Combinations,* SFAS No. 142 *Goodwill and Other Intangible Assets*, SFAS No. 143, *Accounting for Asset Retirement Obligations* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* Each of these standards has a required adoption date of January 1, 2002, except SFAS No. 143, which is required to be adopted in 2003. SFAS No. 141 will impact the manner in which we account for business combinations. SFAS No. 142 will impact the manner in which we account for goodwill and test goodwill for impairment. SFAS No. 143 will impact the accruals we make to retire or remove long-lived assets. SFAS No. 144 will impact how we account for asset impairments and the accounting for discontinued operations.

**2. Acquisitions and Divestitures**

*Texas Midstream Operations*

In December 2000, we completed our purchase of Pacific Gas & Electric's (PG&E's) Texas Midstream operations. The total value of the transaction was $887 million, including assumed debt of approximately $527 million. The transaction was accounted for as a purchase and is included in our Field Services segment.

The operations acquired consisted of 7,500 miles of intrastate natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing and fractionation plants that currently process 1.5 Bcf/d, and rights to 7.2 Bcf of natural gas storage capacity. In March 2001, we sold some of these acquired natural gas liquids transportation and several fractionation assets to El Paso Energy Partners for approximately $133 million.

*Divestitures*

During 2000, we sold East Tennessee Natural Gas Company to comply with a FTC order related to El Paso's merger with Sonat. This merger was accounted for by El Paso as a pooling of interests. Net proceeds from the sale were approximately $386 million and we recognized an extraordinary gain of $77 million, net of income taxes of $51 million. Our treatment of this gain as an extraordinary item was consistent with that of our parent company, El Paso. In December 2000, we sold our interest in Oasis Pipeline Company to comply with a FTC order related to our acquisition of PG&E's Texas Midstream assets. We incurred a loss on this transaction of approximately $19 million, net of income taxes of $10 million. We recorded the gains and losses on these sales as extraordinary items in our income statement. This treatment was consistent with that of El Paso.

As a result of El Paso's merger with The Coastal Corporation, we were required by the FTC to sell our Midwestern Gas Transmission system. We completed this sale in April 2001. Net proceeds were approximately $95 million, and we recognized an extraordinary gain of $38 million, net of income taxes of $21 million. Additionally, El Paso Energy Partners sold its interests in several offshore assets under a FTC order related to El Paso's merger with Coastal. These sales resulted in a $25 million loss to the partnership. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million. These payments were recorded as merger-related costs.

In February 2002, El Paso announced the sale of several of our midstream assets to El Paso Energy Partners for total consideration of $750 million. The assets to be sold include:

- 9,400 miles of intrastate transmission pipelines;
- 1,300 miles of gathering systems in the Permian Basin; and
- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

### 3. Merger-Related Costs and Asset Impairment Charges

During each of the three years ended December 31, we recorded merger-related costs associated with El Paso's mergers with Coastal and Sonat. These mergers were accounted for as a pooling of interests and asset impairment charges, as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | | (In millions) | |
| Merger-related costs | $ 35 | $— | $72 |
| Asset impairments | 73 | 11 | 3 |
| | $108 | $11 | $75 |

*Merger-Related Costs.* Our merger-related costs relate to El Paso's mergers with Coastal and Sonat and consisted of the following:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | | (In millions) | |
| Employee severance, retention and transition costs | $ 6 | $ — | $ — |
| Merger-related asset impairments | — | — | 63 |
| Other | 29 | — | 9 |
| | $ 35 | — | $ 72 |

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of El Paso's merger-related workforce reduction and consolidation. These costs were expensed as incurred and have been paid. Other consists of make-whole commitments related to a series of payments we will make to El Paso Energy Partners in connection with the FTC's ordered divestiture of interests in assets owned by the partnership in connection with the Coastal merger and other miscellaneous charges. These will be paid quarterly through 2003.

*Asset Impairments.* The 2001 asset impairment charges resulted from the write-downs of our investments in several international power projects in our Merchant Energy segment. The 2000 charges consisted of the impairment of a domestic gas processing facility in our Field Services segment. The 1999 charge consisted of discontinued capital projects. The impairments in these periods were primarily a result of weak or changing economic conditions causing permanent declines in the value of these assets, and the charges taken for all assets were based on a comparison of each asset's carrying value to its estimated fair value based on future estimated cash flows. These assets continue to be held for use, or their operations have been suspended.

## 4. Income Taxes

Pretax income before extraordinary items and cumulative effect of accounting change are composed of the following for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| United States | $960 | $660 | $215 |
| Foreign | 29 | 64 | 56 |
| | $989 | $724 | $271 |

The following table reflects the components of income tax expense included in income before extraordinary items and cumulative effect of accounting change for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Current | | | |
| Federal | $ (2) | $ (8) | $ 21 |
| State | (11) | (27) | (16) |
| Foreign | 23 | 7 | 11 |
| | 10 | (28) | 16 |
| Deferred | | | |
| Federal | 313 | 234 | 64 |
| State | 8 | 39 | 6 |
| Foreign | (11) | (3) | (1) |
| | 310 | 270 | 69 |
| Total income tax expense | $320 | $242 | $ 85 |

Our income tax expense included in income before extraordinary items and cumulative effect of accounting change differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Income tax expense at the statutory federal rate of 35% | $346 | $253 | $95 |
| Increase (decrease) | | | |
| State income tax, net of federal income tax benefit | (2) | 8 | (7) |
| Dividend exclusion | (9) | (11) | (6) |
| Non-deductible portion of merger-related costs | — | — | 5 |
| Foreign income taxed at different rates | 13 | (19) | (4) |
| Other | (28) | 11 | 2 |
| Income tax expense | $320 | $242 | $85 |
| Effective tax rate | 32% | 33% | 31% |

The following are the components of our net deferred tax liability at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Deferred tax liabilities | | |
| Property, plant and equipment | $1,775 | $1,884 |
| Investments in unconsolidated affiliates | 230 | 113 |
| Price risk management activities | 475 | 244 |
| Other | 197 | 138 |
| Total deferred tax liability | 2,677 | 2,379 |
| Deferred tax assets | | |
| U.S. net operating loss and tax credit carryovers | 386 | 235 |
| Employee benefit and deferred compensation obligations | 53 | 78 |
| Environmental liability | 86 | 71 |
| Other liabilities | 384 | 397 |
| Valuation allowance | (2) | (2) |
| Total deferred tax asset | 907 | 779 |
| Net deferred tax liability | $1,770 | $1,600 |

At December 31, 2001, the portion of the cumulative undistributed earnings of our foreign subsidiaries and foreign corporate joint ventures on which we have not recorded U.S. income taxes was approximately $212 million. Since these earnings have been or are intended to be indefinitely reinvested in foreign operations, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in other comprehensive income.

Under El Paso's tax sharing policy, we are allocated the tax benefit associated with our employees' exercise of non-qualified stock options and the vesting of restricted stock as well as restricted stock dividends. This allocation reduced taxes payable by $9 million in 2001, $22 million in 2000 and $7 million in 1999. These benefits are included in additional paid-in capital in our balance sheets.

As of December 31, 2001, we had alternative minimum tax credits of $23 million that carryover indefinitely. The table presented below details the net operating loss carryovers periods. Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of the IRS regulations.

| | Carryover Period | | | | | |
|---|---|---|---|---|---|---|
| | 2002 | 2003-2010 | 2011-2015 | 2016-2020 | 2021 | Total |
| | | | (In millions) | | | |
| Net operating loss | $— | $45 | $181 | $581 | $229 | $1,036 |

We recorded a valuation allowance to reflect the estimated amount of deferred tax assets which may not be realized due to the expiration of net operating loss carryovers of an acquired company.

## 5. Financial Instruments and Price Risk Management Activities

*Fair Value of Financial Instruments*

Following are the carrying amounts and estimated fair values of our financial instruments as of December 31:

| | 2001 | | 2000 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | | (In millions) | | |
| Balance sheet financial instruments: | | | | |
| Investments | $ 28 | $ 28 | $ 62 | $ 62 |
| Long-term debt, including current maturities | 1,631 | 1,592 | 1,977 | 2,004 |
| Trading instruments | | | | |
| Futures contracts | (172) | (172) | 137 | 137 |
| Option contracts[1] | 557 | 557 | (118) | (118) |
| Swap and forward contracts[1] | (103) | (103) | 1,150 | 1,150 |
| Other financial instruments: | | | | |
| Non-trading instruments[2] | | | | |
| Commodity swap and forward contracts | $ 23 | $ 23 | $ — | $ — |

(1) Excludes all physical contracts, including transportation capacity, tolling agreements and natural gas in storage held for trading purposes since these do not constitute financial instruments.

(2) On January 1, 2001, we adopted SFAS No. 133. Under SFAS No. 133, all derivative instruments are recorded at their fair value in our financial statements.

As of December 31, 2001 and 2000, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments based on quoted market prices, current market conditions, estimates we obtained from third-party brokers or dealers, or amounts derived using valuation models.

*Trading and Non-Trading Price Risk Management Activities*

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Trading price risk management activities: | | |
| Futures contracts | $ (172) | $ 137 |
| Option contracts | | |
| Financial instruments | 557 | (118) |
| Physical contracts[1] | 897 | 659 |
| Total option contracts | 1,454 | 541 |
| Swap and forward contracts | | |
| Financial instruments | (103) | 1,150 |
| Physical contracts[1] | 163 | 304 |
| Total swap and forward contracts | 60 | 1,454 |
| Non-commodity contracts | (5) | 11 |
| Net assets from trading price risk management activities | 1,337 | 2,143 |
| Non-trading price risk management activities: | | |
| Swap and forward contracts | 23 | — |
| Net assets from non-trading price risk management activities | 23 | — |
| Net assets from price risk management activities | $1,360 | $2,143 |

[1] Physical contracts include transportation capacity, tolling agreements and natural gas in storage held for trading purposes.

*Commodity Trading Activities*

We recognized gross margins from our trading activities of $675 million and $406 million for the year ended December 31, 2001 and 2000. The fair value of commodity and energy related contracts entered into for trading purposes as of December 31, 2001 and 2000, and the average fair value of those instruments are set forth below:

| | Assets | Liabilities | Average Fair Value for the Year Ended December 31,[1] |
|---|---|---|---|
| | | (In millions) | |
| **2001** | | | |
| Futures contracts | $ — | $ (172) | $ 72 |
| Option contracts | 1,822 | (368) | 1,738 |
| Swap and forward contracts | 2,838 | (2,778) | (43) |
| **2000** | | | |
| Futures contracts | $ 137 | $ — | $ 266 |
| Option contracts | 2,134 | (1,593) | 589 |
| Swap and forward contracts | 3,639 | (2,185) | 518 |

[1] Computed using the net asset (liability) balance at the end of each month end.

*Notional Amounts and Terms of Trading Price Risk Management Activities*

The notional amounts and terms of our energy commodity financial instruments at December 31, 2001, and 2000 are set forth below:

| | Fixed Price Payor | Fixed Price Receiver | Maximum Terms in Years |
|---|---|---|---|
| **2001** | | | |
| Energy Commodities: | | | |
| Natural gas (TBtu) | 23,407 | 23,259 | 27 |
| Power (Terawatt Hours) | 655 | 671 | 19 |
| Crude oil and refined products (MMBbls) | 15 | 20 | 5 |
| Weather (thousands of degree days) | 468 | 469 | 2 |
| Energy capacity (Gigawatt hours) | 33 | 50 | 12 |
| Emissions (MTons) | 148 | 178 | 1 |
| **2000** | | | |
| Energy Commodities: | | | |
| Natural gas (TBtu) | 34,306 | 29,896 | 27 |
| Power (Terawatt Hours) | 133 | 143 | 20 |
| Crude oil and refined products (MMBbls) | 8 | 8 | 6 |
| Weather (thousands of degree days) | 133 | 135 | — |
| Energy capacity (Gigawatt hours) | 22 | 29 | 3 |

The notional amounts included in the table above reflect the contracted notional volumes multiplied by the number of delivery periods remaining under the related contracts. These notional amounts are not indicative of future cash flows as we may decide to sell the contracts into the commodity markets in the future.

The notional amount and terms of foreign currency forward purchases and sales and interest rate swaps and futures at December 31, 2001 and 2000, were as follows:

| | Notional Volume | | Maximum Term in Years |
|---|---|---|---|
| | Buy | Sell | |
| **2001** | | | |
| Foreign Currency (in millions) | | | |
| Canadian dollars | 401 | 291 | 10 |
| Interest Rates (in millions) | | | |
| 3-Month LIBOR | 145 | 68 | 20 |
| **2000** | | | |
| Foreign Currency (in millions) | | | |
| Canadian dollars | 1,095 | 441 | 8 years |
| Korean Won | — | 132,500 | 1 month |
| Philippine Peso | — | 4,392 | 1 month |

The weighted average maturity of our entire portfolio of price risk management activities was approximately four years as of December 31, 2001, and two years as of December 31, 2000.

*Market and Credit Risks*

We serve a diverse group of customers that require a wide variety of financial structures, products and terms. This diversity requires us to manage, on a portfolio basis, the resulting market risks inherent in these transactions subject to parameters established by our risk management committee. We monitor market risks through a risk control committee operating independently from the units that create or actively manage these risk exposures to ensure compliance with El Paso's stated risk management policies.

We measure and adjust the risk in our portfolio in accordance with mark-to-market and other risk management methodologies which utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances (including cash in advance, letters of credit, and guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. The counterparties associated with our assets from trading price risk management activities are summarized as follows:

| | Assets from Trading Price Risk Management Activities as of December 31, 2001 | | |
|---|---|---|---|
| | Investment Grade[(1)] | Below Investment Grade[(1)(2)] | Total[(3)(4)] |
| | (In millions) | | |
| Energy marketers | $1,462 | $370 | $1,832 |
| Financial institutions | 189 | — | 189 |
| Oil and natural gas producers | 693 | 13 | 706 |
| Natural gas and electric utilities | 1,291 | 83 | 1,374 |
| Industrials | 21 | 18 | 39 |
| Municipalities | 223 | — | 223 |
| Natural gas and electric utilities not publicly rated | 99 | 2 | 101 |
| Total assets from trading price risk management activities | $3,978 | $486 | $4,464 |

| | Assets from Trading Price Risk Management Activities as of December 31, 2000 | | |
|---|---|---|---|
| | Investment Grade[(1)] | Below Investment Grade[(1)(2)] | Total[(3)] |
| | (In millions) | | |
| Energy marketers | $2,461 | $ 8 | $2,469 |
| Financial institutions | 1,161 | — | 1,161 |
| Oil and natural gas producers | 613 | — | 613 |
| Natural gas and electric utilities | 1,496 | 54 | 1,550 |
| Industrials | 98 | 2 | 100 |
| Municipalities | 17 | — | 17 |
| Natural gas and electric utilities not publicly rated | 10 | 1 | 11 |
| Total assets from trading price risk management activities | $5,856 | $ 65 | $5,921 |

(1) "Investment Grade" and "Below Investment Grade" are primarily determined using publicly available credit ratings, or if a counterparty is not publicly rated, a minimum implied credit rating through internal credit analysis. "Investment Grade" includes counterparties with a minimum Standard & Poor's rating of BBB− or Moody's rating of Baa3. "Below Investment Grade" includes counterparties with a credit rating that do not meet the criteria of "Investment Grade".

(2) As of December 31, 2001, we required collateral, which encompasses margins, standby letters of credit, and parent company guarantees, for $375 million of the $486 million, or 77%, from counterparties included in "Below Investment Grade".

(3) We had one customer that comprised greater than 5 percent of assets from price risk management activities as of December 31, 2001. Although this customer was considered below investment grade, our position with this counterparty was fully collateralized through margins and standby letters of credit. We had one customer that comprised greater than 5 percent of assets from price risk management activities as of December 31, 2000. The customer was considered investment grade.

(4) Counterparty total does not include natural gas in storage or marketable securities held for trading purposes of $196 million at December 31, 2001.

This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

*Non-Trading Price Risk Management Activities*

We also utilize derivative financial instruments for non-trading activities to mitigate market price risk associated with significant physical transactions. Non-trading commodity activities are accounted for using hedge accounting provided they meet hedge accounting criteria. Non-trading activities are conducted through exchange traded futures contracts, swaps, and forward agreements with third parties.

The notional amounts and terms of contracts held for purposes other than trading were as follows at December 31:

| | 2001 | | | 2000 | | |
|---|---|---|---|---|---|---|
| | Notional Volume | | Maximum | Notional Volume | | Maximum |
| | Buy | Sell | Term | Buy | Sell | Term |
| Commodity | | | | | | |
| Natural gas (TBtu) | 16 | 31 | 3 months | 114 | 130 | 5 months |

We also face credit risk with respect to our non-trading activities, and take similar measures as in our trading activities to mitigate this risk. Based upon our policies and risk exposure, we do not anticipate a material effect on our financial position, operating results or cash flows resulting from counterparty non-performance.

**6. Accounting for Hedging Activities**

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $154 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as hedging instruments. The majority of the initial charge related to hedging cash flows from anticipated sales of natural gas for 2001 and 2002. During the year ended December 31, 2001, $132 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the year.

A majority of our commodity sales and purchases are at spot market or forward market prices. We use futures, forward contracts and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of December 31, 2001, the value of cash flow hedges included in accumulated other comprehensive income was a net unrealized loss of $10 million, net of income taxes. We estimate that unrealized losses of $2 million will be reclassified from accumulated other comprehensive income over the next 12 months. Reclassifications occur upon physical delivery of the hedged commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 2 years.

Our accumulated other comprehensive income includes a loss of $20 million, net of income taxes, representing our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges. Included in this loss is a $10 million loss that we estimate will be reclassified from accumulated other comprehensive income over the next 12 months. The maximum term of these cash flow hedges is 2 years, excluding hedges relating to interest rates on variable debt.

For the year ended December 31, 2001, we recognized a net gain of $5 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

## 7. Inventory

Our inventory consisted of the following at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Natural gas in storage | $ 41 | $ 58 |
| Materials and supplies, and other | 38 | 26 |
| Total | $ 79 | $ 84 |

## 8. Debt and Other Credit Facilities

At December 31, 2001, the average interest rate on our commercial paper and short-term borrowings was 3.2%, and at December 31, 2000, it was 7.6%. We had the following short-term borrowings, including current maturities of long-term debt, at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Commercial paper | $424 | $215 |
| Notes payable | 75 | 78 |
| Notes payable to unconsolidated affiliates | — | 9 |
| Current maturities of long-term debt | 68 | 132 |
| | $567 | $434 |

### *Credit Facilities*

We use a commercial paper program to manage our short-term cash requirements. TGP is eligible to borrow up to $1 billion under this program.

El Paso maintains a 3-year, $1 billion, revolving credit and competitive advance facility under which it can conduct short-term borrowings and other commercial credit transactions. This facility expires in 2003 and TGP is a designated borrower under the facility. In June 2001, El Paso replaced an existing 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. TGP is also a designated borrower under this new facility. The interest rate on these facilities varies and was based on LIBOR plus 50 basis points at December 31, 2001. No amounts were outstanding under these facilities at December 31, 2001.

As of December 31, 2001, TGP had $200 million under a shelf registration statement on file with the Securities and Exchange Commission.

The availability of borrowings under these credit and borrowing agreements are subject to specified conditions, which we believe are currently being met. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in these agreements.

Our long-term debt outstanding consisted of the following at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Long-term debt | | |
| El Paso Tennessee | | |
| Notes, 7.25% through 10.0%, due 2008 through 2025 | $ 51 | $ 51 |
| Debentures, 6.5% through 10.0%, due 2001 through 2005 | 12 | 36 |
| Tennessee Gas Pipeline | | |
| Debentures, 6.0% through 7.625% due 2011 through 2037 | 1,386 | 1,386 |
| EPEC Corporation | | |
| Senior note, 9.625% due 2001 | — | 13 |
| Field Services | | |
| Notes, 7.41% through 11.5% due 2001 through 2012 | 164 | 511 |
| Other | 30 | 1 |
| | 1,643 | 1,998 |
| Less: Unamortized discount, net | 12 | 21 |
| Current maturities | 68 | 132 |
| Long-term debt, less current maturities | $1,563 | $1,845 |

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

| | (In millions) |
|---|---|
| 2002 | $ 68 |
| 2003 | 3 |
| 2004 | 31 |
| 2005 | 51 |
| 2006 | 3 |
| Thereafter | 1,487 |
| Total long-term debt, including current maturities | $1,643 |

**9. Minority Interest**

*Gemstone.* As part of the Gemstone transaction, our wholly owned subsidiary, Topaz Investors, L.L.C., issued a minority member interest to a third party investor of Gemstone for $300 million. The third party investor is entitled to a cumulative preferred return of 8.03% on its interest. The agreements underlying this transaction expire in 2004, or earlier if we sell the international power assets owned indirectly by Topaz. The minority member interest is redeemable at liquidation value plus accrued and unpaid dividends.

**10. Commitments and Contingencies**

*Legal Proceedings*

Several of our subsidiaries and affiliates were named defendants in eleven purported class action, municipal or individual lawsuits, and in one shareholder derivative lawsuit, filed in the California state courts. The eleven suits contend that the defendants acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. The shareholder derivative suit contends that El Paso, through its directors, failed to prevent the conduct alleged in several of these underlying cases. We have consolidated nine of the eleven underlying suits into a single San Diego court proceeding, and expect to consolidate the remaining two suits in the near future. In March 2002, the derivative lawsuit was dismissed in California, to be refiled in a state court in Houston, Texas. A listing of these cases is included under the heading *Cases* below.

In September 2001, we received a civil document subpoena from the California Department of Justice, seeking information said to be relevant to the Department's ongoing investigation into the high electricity prices in California. We have produced and expect to continue to produce materials pursuant to this subpoena.

In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes. (In re: natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997.) In May 2001, the court denied the defendants' motions to dismiss.

A number of our subsidiaries were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to the Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In addition, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case, our exposure to the matter and possible legal or settlement strategies and the likelihood of an unfavorable outcome if we determine that an unfavorable outcome is probable and can be estimated, we make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of December 31, 2001, we had reserves totaling $95 million for all outstanding legal matters.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date and our existing accruals, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results or cash flows.

*Environmental Matters*

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2001, we had a reserve of approximately $140 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $87 million in the aggregate for the years 2002 through 2006. These expenditures primarily relate to compliance with clean air regulations.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of polychlorinated biphenyls (PCBs) without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs, and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the original allegations and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under a 1994 consent order with the EPA. Despite these remediation efforts, the agency may raise additional technical issues or require additional remediation work in the future.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of PCBs and other substances, including those on the EPA List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements.

In May 1995, following negotiations with its customers, TGP filed a stipulation and agreement with the Federal Energy Regulatory Commission (FERC) that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The stipulation and agreement was effective July 1, 1995. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

TGP is a party in proceedings involving federal and state authorities regarding the past use of PCBs in its starting air systems. TGP executed a consent order in 1994 with the EPA governing the remediation of the relevant compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

We have been designated, and have received notice that we could be designated or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 6 active sites under CERCLA or state equivalents. We have sought to resolve our liability as a PRP at these CERCLA sites, as appropriate, through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2001, we have estimated our share of the remediation costs at these sites to be between $1 million and $2 million and have provided reserves that we believe are adequate for such costs. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in the determination of our estimated liabilities. We presently believe that based on our existing reserves, and information known to date, the impact the costs associated with these CERCLA sites will not have a material adverse effect on our financial position, operating results or cash flows.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations, and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate.

*Rates and Regulatory Matters*

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with FERC alleging that El Paso Natural Gas Company's (EPNG), a subsidiary of El Paso Corporation, sale of approximately 1.2 Bcf/d of California capacity to El Paso Merchant Energy Company, our subsidiary, was anti-competitive and an abuse of the affiliate relationship under FERC's policies. Other parties in the proceeding requested that the original complaint be set for hearing and that Merchant Energy pay back any profits it has earned under the contract. In March 2001, FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or Merchant Energy had market power and, if so, had exercised it. In October 2001, the administrative law judge issued a proposed decision finding that El Paso did not exercise market power and that the market power portion of the CPUC's complaint should be dismissed. The decision further found that El Paso had violated FERC's marketing affiliate regulations. The judge's proposed decision has been briefed to, and will be effective only if approved by, the FERC. On October 30, 2001, the Market Oversight and Enforcement (MOE) section of the FERC's office of the General Counsel filed comments in this proceeding stating that record development at the trial was inadequate to conclude that EPNG complied with FERC's regulation. We filed a motion to strike the MOE's pleading, but in December 2001, the FERC denied our motion and remanded the proceeding to the administrative law judge for a supplemental hearing on the availability of capacity at EPNG's California delivery points. The hearing commenced on March 21, 2002.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment, including financial guarantees, of approximately $182 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The appeal was heard at the Western Australia Supreme Court in November 2001 and a decision from the court is expected in the middle of 2002. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity and debt capacity, possibly reducing the value of our investment by up to $122 million.

In September 2001, FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

While we cannot predict with certainty the final outcome or the timing of the resolution of all of our rates and regulatory matters, we believe the ultimate resolution of these issues, based on information known to date, will not have a material adverse effect on our financial position, results of operations or cash flows.

*Other Matters*

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. El Paso, through various of its subsidiaries, had contracts with Enron North America and Enron Power Marketing for the trading of physical gas and power and financial derivatives. We established reserves for potential losses related to the receivables under our marketing and trading contracts that we believe are adequate. In addition, we have terminated most of our trading related contracts as a result of Enron's bankruptcy filings, and are analyzing our damage claims arising from the Enron bankruptcy proceedings.

Our foreign investments are subject to risks and unforeseen obstacles that, in many cases are beyond our control or ability to manage. We attempt to manage or limit these risks through our due diligence and partner selection processes, through the denomination of foreign transactions, where possible, in U.S. dollars, and by maintaining insurance coverage, whenever economical and obtainable.

We currently have one power plant in Pakistan, with a total investment, including financial guarantees on this project, of approximately $50 million. While we are aware of no specific threats or actions against this power plant, events in that region, including possible retaliation for American military actions, could impact this project and our related investments. At this time, we believe that through a combination of commercial insurance, political insurance, and rights under contractual obligations, our financial exposure in Pakistan from acts of war, hostility, terrorism, or political instability is not material. It is possible, however, that new information, future developments in the region, or the inability of a party or parties to fulfill their contractual obligations could cause us to reassess our potential exposure.

We also have investments in oil and natural gas, power and pipeline projects in Argentina with an aggregate investment, including financial guarantees, of approximately $381 million. Economic conditions in Argentina have significantly deteriorated during 2001, and the Argentine government has recently defaulted on its public debt obligations. In addition, the government has imposed several changes in law in the first quarter of 2002, including: (i) repeal of the one-to-one exchange rate for the Argentine Peso with U.S. dollar; (ii) a mandate that all contracts and obligations previously denominated in U.S. dollars be re-negotiated and denominated in Argentine Pesos; and (iii) a tax imposed on hydrocarbon and potentially on electric power exports. The Argentine Peso devaluation, combined with the new law changes, effectively convert our projects' contracts from U.S. dollars to Argentine Pesos and will result in a significant reduction in the value of our investments in Argentina. We are monitoring the situation closely and will pursue all options available to us under our political risk insurance policies and under the international arbitration provisions of the United States — Argentina Bilateral Investment Treaty. Despite the current actions by project management and the options available to us that may mitigate our exposure, we may be required to write down our investment by a substantial amount in the first quarter of 2002.

*Cases*

*The California* cases discussed above are: five filed in the Superior Court of Los Angeles County (*Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000; *Berg v. Southern California Gas Company, et al;* filed December 18, 2000; *County of Los Angeles v. Southern California Gas Company, et al* filed January 8, 2002; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001); two filed in the Superior Court of San Diego County (*John W.H.K. Phillip v. El Paso Merchant Energy* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000); three filed in the Superior Court of San Francisco County (*Sweetie's et al v. El Paso Corporation, et al,* filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al,* filed May 9, 2001; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001); and one filed in the Superior Court of the State of California, County of Alameda (*Dry Creek Corporation v. El Paso Natural Gas Company, et al*, filed December 10, 2001). The shareholder derivative suit now dismissed was styled *Clark, et al v. Allumbaugh, et al,* Superior Court of Orange County, filed August 23, 2001.

*Capital Commitments and Purchase Obligations*

At December 31, 2001, we had capital and investment commitments of $1.5 billion primarily relating to our pipeline and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. We have entered into unconditional purchase obligations for products and services, including financing commitments with one of our joint ventures, totaling $157 million at December 31, 2001. The annual obligations under these agreements are $28 million for 2002, $25 million for 2003, $27 million for 2004 and 2005, $20 million for 2006 and $30 million in total thereafter.

*Operating Leases*

We lease property, facilities and equipment under various operating leases. In 1995, El Paso New Chaco Company (EPNC) entered into an unconditional lease for the Chaco Plant. The lease term expires in 2002, at which time EPNC has an option, and an obligation upon the occurrence of various events, to purchase the plant for a price sufficient to pay the amount of the $77 million construction financing, plus interest and other expenses. If EPNC does not purchase the plant at the end of the lease term, it has an obligation to pay a residual guaranty amount equal to approximately 87 percent of the amount financed, plus interest. We unconditionally guaranteed all obligations of EPNC under this lease.

In October 2001, El Paso Energy Partners acquired an interest in the title holder of the Chaco Plant. As a result, we now make our lease payments to El Paso Energy Partners.

Minimum annual rental commitments at December 31, 2001, were as follows:[1]

| Year Ending December 31, | Operating Leases (In millions) |
|---|---|
| 2002 | $ 7 |
| 2003 | 3 |
| 2004 | 3 |
| 2005 | 2 |
| 2006 | 2 |
| Thereafter | 7 |
| Total | $24 |

(1) These amounts exclude minimum annual rental commitments paid by our parent, which are allocated to us through an overhead allocation.

Rental expense on our operating leases for the years ended December 31, 2001, 2000 and 1999 was $30 million, $15 million, and $13 million.

### 11. Retirement Benefits

*Pension and Retirement Benefits*

El Paso maintains a pension plan to provide benefits as determined by a cash balance formula covering substantially all of its U.S. employees, including our employees. Also, El Paso maintains a defined contribution plan covering its employees, including our employees. El Paso matches 75 percent of participant basic contributions of up to 6 percent, with matching contributions made in El Paso common stock, which participants may diversify at any time. El Paso is responsible for benefits accrued under its plan and allocates the related costs to its affiliates. See Note 15 for a summary of transactions with affiliates.

*Other Postretirement Benefits*

Following our acquisition by El Paso in 1996, we retained responsibility for some of the postretirement medical and life insurance benefits for our former employees of operations previously disposed of, and for employees, including TGP employees, added as a result of the merger who were eligible to retire on December 31, 1996, and did so on or before July 1, 1997. Medical benefits for this closed group of retirees are subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. We have reserved the right to change these benefits. Employees who retired after July 1, 1997, will continue to receive limited postretirement life insurance benefits. Effective February 1, 1992, TGP began recovering through its rates the other postretirement benefits (OPEB) costs included in the June 1993 rate case settlement agreement. To the extent actual OPEB costs differ from the amounts funded, a regulatory asset or liability is recorded.

The following table sets forth the change in benefit obligation, change in plan assets, reconciliation of funded status, and components of net periodic benefit cost for other postretirement benefits as of and for the twelve month period ended September 30:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of period | $ 249 | $ 273 |
| Interest cost | 18 | 19 |
| Participant contributions | 13 | 9 |
| Actuarial loss | — | 1 |
| Benefits paid | (40) | (53) |
| Benefit obligation at end of period | $ 240 | $ 249 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of period | $ 6 | $ 6 |
| Actual return on plan assets | 2 | 1 |
| Employer contributions | 28 | 43 |
| Participant contributions | 13 | 9 |
| Benefits paid | (40) | (53) |
| Fair value of plan assets at end of period | $ 9 | $ 6 |
| Reconciliation of funded status | | |
| Funded status at end of period | $(231) | $(243) |
| Fourth quarter contributions and income | 5 | 11 |
| Unrecognized net actuarial gain | (4) | (3) |
| Unrecognized prior service cost | (9) | (10) |
| Net accrued benefit cost at December 31, | $(239) | $(245) |

The current liability portion of the postretirement benefits was $43 million as of December 31, 2001 and 2000. Benefit costs for each of three years ended December 31 were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | (In millions) | | |
| Benefit cost for the plans includes the following components | | | |
| Interest cost | $18 | $ 19 | $20 |
| Amortization of prior service cost | (1) | (1) | (1) |
| Net benefit cost | $17 | $ 18 | $19 |

Benefit obligations are based upon actuarial estimates as described below:

| | 2001 | 2000 |
|---|---|---|
| Weighted average assumptions | | |
| Discount rate | 7.25% | 7.75% |
| Expected return on plan assets | 7.50% | 7.50% |

Actuarial estimates for our postretirement benefits plans assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 9.5 percent in 2001, gradually decreasing to 6 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in our assumed health care cost trends would have less than a $1 million increase or decrease in our obligation.

## 12. Preferred Stock

As of December 31, 2001, we had authorized 20 million shares of preferred stock. In November 1996, we issued 6 million shares of Series A preferred stock. Holders of shares of Series A preferred stock are entitled to receive cash dividends payable quarterly at the rate of 8¼% of the stated value of $50 per share. It was not redeemable at our option prior to December 31, 2001. After December 31, 2001, the Series A Preferred Stock became redeemable at our option, in whole or in part, upon not less than 30 days' notice at a redemption price of $50 per share, plus unpaid dividends.

## 13. Segment Information

Our business activities are segregated into three segments: Pipelines, Merchant Energy, and Field Services. These segments are strategic business units that offer a variety of different energy products and services. We manage each segment separately as each business requires different technology and marketing strategies.

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through one wholly owned and four partially owned interstate transmission systems along with a partially owned natural gas storage facility.

Our Merchant Energy segment is involved in a broad range of activities in the wholesale energy marketplace, including asset ownership, trading and risk management, and financial services. We buy, sell, and trade natural gas, power, and other energy commodities throughout the world, and own or have interests in 77 power generation plants in 16 countries.

Our Field Services segment provides natural gas gathering, products extraction, fractionation, dehydration, purification, compression, and intrastate transmission services. These services include gathering of natural gas from some of the most prolific and active production areas in the United States, including the San Juan Basin, east and south Texas, Louisiana and the Gulf of Mexico.

The accounting policies of the individual segments are the same as those described in Note 1. Since earnings on equity investments can be a significant component of earnings in several of our segments, we chose to evaluate segment performance based on EBIT. To the extent practicable, results of operations for the years ended December 31, 1999 and 1998 have been reclassified to conform to the current business segment presentation, although such results are not necessarily indicative of the results which would have been achieved had the revised business segment structure been in effect during that period.

| | Segments As of or for the Year Ended December 31, 2001 | | | | |
|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Field Services | Other[(1)] | Total |
| | | | (In millions) | | |
| Revenue from external customers | | | | | |
| Domestic | $ 653 | $29,408 | $1,246 | $ 3 | $31,310 |
| Foreign | — | 1,672 | — | — | 1,672 |
| Intersegment revenue | 77 | 46 | 467 | (590) | — |
| Merger-related costs and asset impairment charges | 1 | 74 | 33 | — | 108 |
| Depreciation, depletion and amortization | 128 | 36 | 86 | 4 | 254 |
| Operating income (loss) | 301 | 588 | 80 | (8) | 961 |
| Other income | 21 | 313 | 2 | — | 336 |

| | Segments As of or for the Year Ended December 31, 2001 | | | | |
|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Field Services (In millions) | Other[(1)] | Total |
| EBIT | 322 | 901 | 81 | (7) | 1,297 |
| Extraordinary items, net of income taxes | (27) | — | — | 65 | 38 |
| Cumulative effect of accounting change net of income taxes | — | 10 | — | — | 10 |
| Assets | | | | | |
| Domestic | 5,047 | 10,471 | 2,517 | 437 | 18,472 |
| Foreign | — | 1,523 | — | — | 1,523 |
| Capital expenditures and investments in unconsolidated affiliates | 335 | 811 | 82 | 7 | 1,235 |
| Total investments in unconsolidated affiliates | 161 | 2,453 | 211 | — | 2,825 |

(1) Includes Corporate and eliminations.

| | Segments As of or for the Year Ended December 31, 2000 | | | | |
|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Field Services (In millions) | Other[(1)] | Total |
| Revenue from external customers | | | | | |
| Domestic | $ 707 | $18,467 | $ 574 | $ 2 | $19,750 |
| Foreign | — | 1,038 | — | — | 1,038 |
| Intersegment revenue | 69 | 16 | 84 | (169) | — |
| Merger-related costs and asset impairment charges | — | — | 11 | — | 11 |
| Depreciation, depletion and amortization | 135 | 27 | 58 | 3 | 223 |
| Operating income (loss) | 335 | 433 | 84 | (12) | 840 |
| Other income (loss) | 19 | 130 | 4 | (5) | 148 |
| EBIT | 354 | 563 | 88 | (17) | 988 |
| Extraordinary items, net of income taxes | (54) | — | (19) | 131 | 58 |
| Assets | | | | | |
| Domestic | 4,991 | 9,749 | 2,543 | 250 | 17,533 |
| Foreign | — | 1,932 | — | — | 1,932 |
| Capital expenditures and investments in unconsolidated affiliates | 186 | 923 | 451 | 18 | 1,578 |
| Total investments in unconsolidated affiliates | 135 | 1,816 | 57 | — | 2,008 |

(1) Includes Corporate and eliminations.

| | Segments As of or for the Year Ended December 31, 1999 | | | | |
|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Field Services | Other[1] | Total |
| | | | (In millions) | | |
| Revenue from external customers | | | | | |
| Domestic | $ 819 | $7,909 | $ 348 | $ 3 | $9,079 |
| Foreign | — | 591 | — | — | 591 |
| Intersegment revenue | 33 | 20 | 74 | (127) | — |
| Merger-related costs and asset impairment charges | — | 67 | 8 | — | 75 |
| Depreciation, depletion and amortization | 146 | 46 | 52 | 3 | 247 |
| Operating income (loss) | 360 | (91) | 46 | (17) | 298 |
| Other income | 23 | 94 | 32 | — | 149 |
| EBIT | 383 | 3 | 78 | (17) | 447 |
| Cumulative effect of accounting change net of income taxes | — | (13) | — | — | (13) |
| Assets | | | | | |
| Domestic | 5,036 | 2,119 | 1,053 | 220 | 8,428 |
| Foreign | — | 1,336 | — | — | 1,336 |
| Capital expenditures and investments in unconsolidated affiliates | 231 | 994 | 141 | 7 | 1,373 |
| Total investments in unconsolidated affiliates | 123 | 1,274 | 112 | — | 1,509 |

(1) Includes Corporate and eliminations.

The reconciliations of EBIT to income before extraordinary items and cumulative effect of accounting change are presented below.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | | (In millions) | |
| Income before interest, income taxes, and other charges | $1,297 | $988 | $447 |
| Non-affiliated interest and debt expense | 149 | 142 | 136 |
| Affiliated interest and debt expense, net | 155 | 122 | 40 |
| Minority interest | 4 | — | — |
| Income taxes | 320 | 242 | 85 |
| Income before extraordinary items and cumulative effect of accounting change | $ 669 | $482 | $186 |

As of December 31, 2001, we had no customers whose revenues exceeded 10 percent of our total revenue. In 2000, Merchant Energy had revenues of $2.1 billion from subsidiaries of Enron Corp. We did not have revenues in excess of 10 percent with any other customer in 2000.

### 14. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Interest paid | $343 | $284 | $208 |
| Income tax payments (refunds) | 46 | 54 | (1) |

## 15. Investments in and Advances to Unconsolidated Affiliates and Transactions with Related Parties

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants, and gathering systems. Our investment balance includes unamortized purchase price differences of $312 million and $343 million as of December 31, 2001 and 2000, that are being amortized over the remaining life of the unconsolidated affiliate's underlying assets. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

| | Country | Net Ownership Interest | Investments 2001 | Investments 2000 | Advances 2001 | Advances 2000 |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| Bear Creek Storage | | 50% | $ 116 | $ 101 | $ — | $ — |
| CE Generation | | 50% | 360 | 354 | — | — |
| Chaparral Investors (Electron) | | 20% | 341 | 268 | 343 | — |
| El Paso Production Offshore I, LP | | 49% | 110 | — | — | — |
| El Paso Energy Partners | | 7% | 64 | 51 | — | — |
| Other Domestic Investments(1) | | various | 257 | 133 | 38 | — |
| Domestic | | | $1,248 | $ 907 | $381 | $ — |
| CAPSA/CAPEX | Argentina | 45% | $ 259 | $ 282 | $ — | $ — |
| Gasoducto del Pacifico Pipeline (Argentina to Chile) | Argentina/Chile | 16% | 71 | 70 | — | — |
| Bolivia to Brazil Pipeline | Bolivia/Brazil | 8% | 50 | 53 | — | — |
| Porto Velho (Gemstone)(2) | Brazil | — | — | 99 | — | — |
| Diamond Power (Gemstone)(2) | Brazil | 50% | 555 | — | — | — |
| Meizhou Wan Generating | China | 25% | 76 | 7 | — | — |
| Enfield Power | UK | 25% | 53 | 40 | — | — |
| Korea Independent Energy Corporation | Korea | 50% | 104 | 108 | — | — |
| Samalayuca | Mexico | 41% | 103 | 93 | — | — |
| Aguaytia Energy | Peru | 24% | 52 | 26 | — | — |
| East Asia Power | Philippines | 46% | — | 51 | — | 67 |
| Other Foreign Investments(1) | various | various | 254 | 272 | 9 | 44 |
| Foreign | | | $1,577 | $1,101 | $ 9 | $111 |
| Total investments in and advances to unconsolidated affiliates | | | $2,825 | $2,008 | $390 | $111 |

(1) Denotes investments less than $50 million.

(2) Contributed to Gemstone in 2001.

Earnings from our unconsolidated affiliates are as follows for each of the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Bear Creek Storage | $ 14 | $ 13 | $ 10 |
| Bolivia to Brazil Pipeline | 1 | — | 4 |
| CAPSA/CAPEX | (12) | 4 | 3 |
| CE Generation | 29 | 35 | 24 |
| Chaparral Investors (Electron) | 75 | (5) | (8) |
| Diamond Power (Gemstone) | 2 | — | — |
| East Asia Power | (4) | (32) | — |
| Gasoducto del Pacifico Pipeline (Argentina to Chile) | 2 | 1 | (1) |
| Korea Investment Energy Corporation | 20 | — | — |
| Porto Velho (Gemstone) | (6) | 1 | — |
| Samalayuca Power | 12 | 17 | 17 |
| Other | 64 | 27 | 12 |
| Total earnings from our unconsolidated affiliates | $197 | $ 61 | $ 61 |

Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $1 million and $0.5 million for December 31, 2001 and 2000 and total assets of $7 million and $47 million for December 31, 2001 and 2000:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | | (Unaudited) (In millions) | |
| Operating results data: | | | |
| Revenues and other income | $954 | $753 | $510 |
| Costs and expenses | 749 | 660 | 444 |
| Income from continuing operations | 205 | 93 | 66 |
| Net income | 197 | 61 | 61 |

| | December 31, | |
|---|---|---|
| | 2001 | 2000 |
| | (Unaudited) (In millions) | |
| Financial position data: | | |
| Current assets | $ 669 | $ 628 |
| Non-current assets | 4,944 | 3,917 |
| Short-term debt | 157 | 239 |
| Other current liabilities | 343 | 230 |
| Long-term debt | 2,352 | 1,981 |
| Other non-current liabilities | 322 | 456 |
| Minority interest | 32 | 37 |
| Equity in net assets | 2,407 | 1,602 |

The following table shows revenues and charges from our unconsolidated affiliates and El Paso's subsidiaries:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | (In millions) | | |
| Revenues | $ 530 | $142 | $ 24 |
| Cost of sales | 2,818 | 369 | 416 |
| Management fee income from unconsolidated affiliates | 150 | 82 | 20 |
| Reimbursement for costs | 104 | 42 | 17 |
| Charges from El Paso | 212 | 160 | 209 |
| Interest income from unconsolidated affiliates | 22 | 13 | 9 |

*Sabine River Investors*

During 1999, El Paso formed Sabine River Investors, L.L.C., a wholly owned limited liability company, and other separate legal entities, for the purpose of generating funds for El Paso to invest in capital projects and other assets. The proceeds are collateralized by specific assets of El Paso, including our 50 percent investment in Bear Creek and 7 percent investment in El Paso Energy Partners.

*Chaparral*

During 1999, we formed a series of companies with a third-party financial investor that we refer to as Chaparral. Chaparral (also known as Electron) was formed to obtain low cost financing to fund the growth of our unregulated domestic power generation and related businesses. Chaparral has acquired and currently owns equity interests in 39 natural gas-fired generation facilities in Arizona, California, Colorado, Connecticut, Florida, Massachusetts, Nevada, New Jersey, New York, Pennsylvania and Rhode Island. Chaparral also owns several operating companies that provide the services required to operate and maintain these facilities and a natural gas service company that provides fuel procurement services to eight of Chaparral's natural gas-fired generation facilities in California.

Total third party capital in Chaparral was $1.15 billion, including $123 million contributed in 1999 and $1,027 million contributed in 2000, of which $1 billion of debt was raised in 2000 by the third party investor through a note issuance that matures in March 2003. In order to lower the cost of this debt, El Paso provided a contingent equity support arrangement to the third party debtholders. El Paso plans to amend this arrangement and replace it with an El Paso financial guaranty in 2002.

We account for our equity investment in Chaparral of $341 million and $268 million at December 31, 2001 and 2000 using the equity method of accounting since we do not have the ability to exercise control over the structure. We also had a note receivable from Chaparral and its subsidiaries of $343 million and it was included in current and long-term receivables from unconsolidated affiliates.

Chaparral has used its funds to acquire the domestic power generation and related businesses described above. In some cases, Chaparral acquired these power generation assets from us. Chaparral acquired power generation assets from us with a value of $94 million and $659 million in 2001 and 2000. We did not recognize any gains or losses on these transactions.

In addition to the financing transactions described above, we have also entered into various contractual agreements with Chaparral related to management and trading activities.

We serve as manager of Chaparral under a management agreement that expires in 2006. We are compensated for the services we provide through an annual performance-based management fee, which amounted to $147 million in 2001 and $80 million in 2000. This performance-based management fee is calculated based on the value of Chaparral's assets as determined using cash flow techniques. We also receive a fixed fee reimbursement for out-of-pocket and third-party expenses we incurred on behalf of Chaparral, which was $20 million for 2001 and 2000.

Our Merchant Energy segment also enters into various contractual agreements with Chaparral and its operating subsidiaries in conjunction with Chaparral's operations. These include agreements to (i) supply natural gas or other fuels to power Chaparral's facilities; (ii) purchase all or a portion of the power produced by Chaparral's facilities; (iii) provide some or all of the power supply that Chaparral is obligated to provide to fulfill agreements it has with third parties; (iv) purchase tolling rights; and (v) provide other services to Chaparral related to its operations. We account for these agreements as trading price risk management activities and recognized revenues of $266 million and $119 million in 2001 and 2000 and costs of sales of $121 million and $42 million in 2001 and 2000 related to these transactions.

*Gemstone*

In November 2001, we formed with a third-party financial investor a series of companies that we refer to as Gemstone. Gemstone was formed to provide a financing vehicle through which we fund the development and growth of our power generation, merchant energy, and related businesses in Brazil.

The third party financial investor contributed into Gemstone $50 million in cash and raised an additional $950 million through a note issuance that matures in October 2004. To lower the cost of this debt, El Paso provided a contingent equity support arrangement to the third party debtholders. El Paso plans to amend this arrangement and replace it with an El Paso financial guaranty in 2002. The proceeds were used by Gemstone to acquire a Brazilian power investment, invest $300 million in preferred securities of one of our consolidated subsidiaries and temporarily invest excess proceeds of $462 million in short-term notes from El Paso. The preferred securities of our subsidiary entitle Gemstone to a preferred return of 8.03%.

We contributed $280 million in cash as well as several Brazilian investments with a total value of $274 million in exchange for our interest in Gemstone. Gemstone used the funds we contributed to acquire an interest in electric generation assets in Brazil.

Our investment in Gemstone as of December 31, 2001, is $555 million, and we account for our investment using the equity method of accounting since we do not have the ability to exercise control over the entity. We account for the investor's preferred interest in our consolidated subsidiary as a minority interest in our balance sheet and the preferred return as minority interest expense in our income statement.

Under our management agreement with Gemstone, we earn a cost-based management fee. This fee was not significant in 2001. We have also entered into a participation agreement with one of Gemstone's power generation interests whereby we earn a fee for managing, constructing, and operating the related facilities and marketing and distributing the energy produced by these facilities. This fee was not significant in 2001.

*El Paso Energy Partners*

In 2001, as a result of a FTC order related to El Paso's merger with Coastal, El Paso Energy Partners sold its interest in several offshore assets including seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from these sales were approximately $135 million and resulted in a loss to the partnership of approximately $25 million. As consideration for these sales, we committed to pay El Paso Energy Partners a series of payments totaling $29 million. This amount, as well as our proportionate share of the losses on the sale of the partnership's assets, were recorded as merger-related costs.

During 2001, El Paso Energy Partners issued a total of 7.9 million common units reducing our ownership interest in the common units to 7 percent.

We perform the daily operations for El Paso Energy Partners on behalf of the partnership's general partner, DeepTech International Inc., an affiliate of ours. We are reimbursed for these and other services we provide for El Paso Energy Partners. The management agreement between DeepTech and El Paso Energy Partners expires on June 30, 2002, and may be terminated thereafter upon 90 days notice by either party. We recorded reimbursements of $34 million and $22 million in 2001 and 2000.

In addition to the management activities described above, we enter into transactions with El Paso Energy Partners in the normal course of business for the sale of natural gas and for services such as transportation and fractionation, storage, processing and other types of operational services. These activities are based on the same terms as non-affiliates. We recognized revenues of $28 million and $14 million in 2001 and 2000 and cost of sales of $43 million and $22 million in 2001 and 2000.

In February 2002, we announced the sale of additional midstream assets to El Paso Energy Partners for total consideration of $750 million. The primary assets to be sold include:

- 9,400 miles of intrastate transmission pipelines;

- 1,300 miles of gathering systems in the Permian Basin; and

- a 42.3 percent non-operating interest in the Indian Basin gas processing and treating plant and associated gathering lines.

*El Paso and Subsidiaries*

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We had net borrowings of $2,364 million at December 31, 2001, at a market rate of interest which was 2.1%. At December 31, 2000, we had borrowed $3,690 million at a market rate of 6.7%. In addition, we have demand note receivables with El Paso of $40 million at December 31, 2001, with interest rates that range from 2.7% to 3.1%. At December 31, 2000, demand note receivables were $15 million, with an interest rate of 7.3%. We also had a note payable to El Paso of $35 million at December 31, 2001, with a market rate.

At December 31, 2001, we had accounts and notes receivable from El Paso's subsidiaries of $56 million and $10 million at December 31, 2000. In addition, we had accounts payable to El Paso's subsidiaries of $530 million and $69 million at December 31, 2000. The balances arose in the normal course of business.

El Paso allocates a portion of its general and administrative expenses to us. The allocation is based on the estimated level of effort devoted to our operations and the relative size of our revenues, gross property and payroll. During 2001, we performed some operational, financial, accounting and administrative services for subsidiaries of El Paso CGP, our affiliate. We recorded the amounts billed as a reduction to our operating expenses. We believe the allocation methods are reasonable.

In addition, we enter into transactions with other El Paso subsidiaries in the ordinary course of our business to transport, sell and purchase natural gas and various contractual agreements for trading activities. As a result of El Paso's merger with Coastal, our affiliated activities have increased. Services provided by these affiliates for our benefit are based on the same terms as non-affiliates.

## 16. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

| | Quarters Ended | | | |
|---|---|---|---|---|
| | December 31 | September 30 | June 30 | March 31 |
| | (In millions) | | | |
| 2001 | | | | |
| Operating revenues | $6,739 | $7,747 | $8,314 | $10,182 |
| Merger-related costs and asset impairment charges | 35 | — | 44 | 29 |
| Operating income | 211 | 259 | 190 | 301 |
| Income before extraordinary items and cumulative effect of accounting change | 211 | 170 | 120 | 168 |
| Cumulative effect of accounting change, net of income taxes | 10 | — | — | — |
| Extraordinary items, net of income taxes | — | — | 38 | — |
| Net income | 221 | 170 | 158 | 168 |
| 2000 | | | | |
| Operating revenues | $7,234 | $6,707 | $3,980 | $ 2,867 |
| Merger-related costs and asset impairment charges | 11 | — | — | — |
| Operating income | 286 | 153 | 239 | 162 |
| Income before extraordinary items | 144 | 90 | 140 | 108 |
| Extraordinary items, net of income taxes | (19) | — | — | 77 |
| Net income | 125 | 90 | 140 | 185 |

(1) Reflects the adoption of the Emerging Issues Task Force Topic D-105. This policy was adopted during the fourth quarter with an effective adoption date of January 1, 2001. See Note 1 for a further discussion of this change in accounting.

## REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of
El Paso Tennessee Pipeline Co.:

In our opinion, the consolidated financial statements listed in the Index appearing under Item 14(a)(1) present fairly, in all material respects, the financial position of El Paso Tennessee Pipeline Co. and its subsidiaries at December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 14(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Notes 1 and 6, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, on January 1, 2001, and Emerging Issues Task Force Topic D-105, *Accounting in Consolidation for Energy Trading Contracts between Affiliated Entities When the Activities of One but not Both Affiliates Are Within the Scope of Issue 98-10* on December 31, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2002

## SCHEDULE II

## EL PASO TENNESSEE PIPELINE CO.
## VALUATION AND QUALIFYING ACCOUNTS

### Years Ended December 31, 2001, 2000 and 1999
### (In millions)

| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| 2001 | | | | | |
| Allowance for doubtful accounts | $100 | $124 [1] | $ (1) | $ — | $223 |
| Valuation allowance on deferred tax assets | 2 | — | — | — | 2 |
| Legal reserves | 235 | 14 | (124) [2] | (30) [3] | 95 |
| Environmental reserves | 122 | — | 30 | (12) | 140 |
| Regulatory reserves | 33 | (12) [4] | (11) [4] | — | 10 |
| 2000 | | | | | |
| Allowance for doubtful accounts | $ 23 | $ 85 [1] | $ (4) | $ (4) [3] | $100 |
| Valuation allowance on deferred tax assets | 4 | — | — | (2) | 2 |
| Legal reserves | 18 | 9 | 211 [5] | (3) | 235 |
| Environmental reserves | 130 | 7 | 1 | (16) | 122 |
| Regulatory reserves | 38 | (5) | — | — | 33 |
| 1999 | | | | | |
| Allowance for doubtful accounts | $ 23 | $ 6 | $ (2) | $ (4) [3] | $ 23 |
| Valuation allowance on deferred tax assets | 5 | — | — | (1) | 4 |
| Legal reserves | 33 | (9) | (4) | (2) | 18 |
| Environmental reserves | 148 | 2 | 4 | (24) [3] | 130 |
| Regulatory reserves | 113 | (75) [6] | — | — | 38 |

(1) Primarily relates to our Merchant Energy segment's reserves booked for collectibility of receivables related to Enron in 2001 and California in 2000 and 2001.

(2) In 2001, we finalized our purchase price adjustment to property, plant and equipment for the legal reserves related to our PG&E acquisition.

(3) Primarily accounts written off.

(4) Upon favorable resolution of issues related to natural gas purchase contracts, we reversed the regulatory reserve to revenue and the regulatory asset account.

(5) Of this amount, $53 million was the legal reserve we acquired in connection with our purchase of PG&E Texas midstream operations. We recorded an additional $159 million in property, plant and equipment related to purchase price adjustments on our PG&E acquisition.

(6) Primarily represents favorable resolution of various regulatory issues.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

# PART III

## ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information appearing under the captions "Directors Elected by Common Stockholders," "Proposal No. 1 — Nominee for Election of Director by Series A Preferred Stockholders" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant" and is incorporated herein by reference.

## ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF BENEFICIAL OWNERS AND MANAGEMENT

Information appearing under the captions "Security Ownership of a Beneficial Owner and Management of the Company" and "Security Ownership of Management of El Paso Corporation" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information appearing under the caption "Relationship with El Paso Corporation" in our proxy statement for the 2002 Annual Meeting of Stockholders is incorporated herein by reference.

## PART IV

### ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

**(a) The following documents are filed as a part of this report:**

1. Financial statements.

Our consolidated financial statements included in Part II, Item 8 of this report:



2. Financial statement schedules and supplementary information required to be submitted.



Schedules other than that listed above are omitted because they are not applicable



**(b) Reports on Form 8-K:**

None.

## EL PASO TENNESSEE PIPELINE CO.

## EXHIBIT LIST
## December 31, 2001

Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

| Exhibit Number | Description |
|---|---|
| 3.A | — Restated Certificate of Incorporation, dated May 11, 1999 (Exhibit 3.A to our 1999 First Quarter Form 10-Q). |
| 3.B | — By-laws as amended March 1, 1998 (Exhibit 3.B to our 1997 Form 10-K). |
| 4.A | — Indenture dated as of March 4, 1997, between TGP and The Chase Manhattan Bank (Exhibit 4.1 to our 1997 Form 10-K); First Supplemental Indenture dated as of March 13, 1997, between TGP and The Chase Manhattan Bank (Exhibit 4.2 to our 1997 Form 10-K); Second Supplemental Indenture dated as of March 13, 1997, between TGP and The Chase Manhattan Bank (Exhibit 4.3 to our 1997 Form 10-K); Third Supplemental Indenture dated as of March 13, 1997, between TGP and The Chase Manhattan Bank (Exhibit 4.4 to our 1997 Form 10-K); Fourth Supplemental Indenture dated as of October 9, 1998, between TGP and The Chase Manhattan Bank (Exhibit 4.2 to our Form 8-K filed October 9, 1998). |
| 10.A | — $3,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement, dated as of August 11, 2001, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.A to our 2001 Second Quarter Form 10-Q). |
| 10.B | — $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated as of August 4, 2000, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.B to our 2000 Third Quarter Form 10-Q). |
| *21 | — List of Subsidiaries. |

**Undertaking**

The undersigned Registrant hereby undertakes, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of long-term debt of Registrant and its consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of the total consolidated assets of Registrant and its consolidated subsidiaries.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Tennessee Pipeline Co. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 25th day of March 2002.

EL PASO TENNESSEE PIPELINE CO.
Registrant

By: /s/ WILLIAM A. WISE

William A. Wise
*Chairman of the Board, President and Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso Tennessee Pipeline Co. and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ WILLIAM A. WISE<br>(William A. Wise) | Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer) | March 25, 2002 |
| /s/ H. BRENT AUSTIN<br>(H. Brent Austin) | Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer) | March 25, 2002 |
| /s/ JOEL RICHARDS III<br>(Joel Richards III) | Executive Vice President and Director | March 25, 2002 |
| /s/ PEGGY A. HEEG<br>(Peggy A. Heeg) | Executive Vice President: Law | March 25, 2002 |
| /s/ JEFFREY I. BEASON<br>(Jeffrey I. Beason) | Senior Vice President, Controller and Director (Principal Accounting Officer) | March 25, 2002 |
| /s/ KENNETH L. SMALLEY<br>(Kenneth L. Smalley) | Director | March 25, 2002 |