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 1-7176**

# El Paso CGP Company

(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| **Delaware**<br>(State or Other Jurisdiction of Incorporation or Organization) | **74-1734212**<br>(I.R.S. Employer Identification No.) |
| **El Paso Building**<br>**1001 Louisiana Street**<br>**Houston, Texas**<br>(Address of Principal Executive Offices) | **77002**<br>(Zip Code) |

**Telephone Number: (713) 420-2600**

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

| Title of Each Class | Name of Each Exchange on which Registered |
|---|---|
| 8.375% Coastal Trust Preferred Securities issued by Coastal Finance I<br>Growth PRIDES<br>Income PRIDES | 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, 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: None**

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

Common Stock, par value $1.00 per share. Shares outstanding on March 28, 2002: 1,000

**EL PASO CGP COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1)(a) AND (b) TO FORM 10-K AND IS, THEREFORE, FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.**

**Documents incorporated by reference: None**

## EL PASO CGP COMPANY

## TABLE OF CONTENTS



* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

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 |
| Bcfe | = billion cubic feet of gas equivalents | MWh | = megawatt hours |
| MBbls | = thousand barrels | MMWh | = thousand megawatt hours |
| MMBbls | = million barrels | TBtu | = trillion British thermal units |
| MMBtu | = million British thermal units | Tcfe | = trillion cubic feet of gas equivalents |
| 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 of oil 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 "Coastal", we are describing El Paso CGP Company and/or our subsidiaries.

# PART I

## ITEM 1. BUSINESS.

### General

We are a Delaware corporation originally founded in 1955. In January 2001, we became a wholly owned subsidiary of El Paso Corporation through our merger with a wholly owned El Paso subsidiary. In the merger, holders of our common stock and Class A common stock received 1.23 shares of El Paso common stock for each outstanding common share; holders of our Series A and Series B convertible preferred stock received 9.133 shares of El Paso common stock for each outstanding convertible preferred share; and holders of our Series C convertible preferred stock received 17.98 shares of El Paso common stock for each outstanding convertible preferred share. In addition, holders of our outstanding stock options received shares of El Paso common stock based on the fair value of these options on the date of the merger. As a result, El Paso owns 100 percent of our common equity. On January 30, 2001, we changed our name from The Coastal Corporation to El Paso CGP Company.

Our principal operations include:

- natural gas transportation, gathering, processing and storage;
- natural gas and oil exploration, development and production;
- energy and energy-related commodities and product marketing;
- power generation;
- energy infrastructure facility development and operation;
- petroleum refining;
- chemicals production; and
- coal mining.

### Segments

Our operations are segregated into four primary business segments: Pipelines, Merchant Energy, Production 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. These segments changed from those reported in 2000 as a result of our merger with El Paso. Information for all prior periods has been restated to reflect the current segment presentation. 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 15, which is incorporated herein by reference.

Our Pipelines segment owns or has interests in approximately 20,300 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 four of the largest consuming regions in the U.S.: the Gulf Coast, California, the Northeast and the Midwest. Our U.S. pipeline systems also own or have interests in over 280 Bcf of storage capacity used to provide a variety of services to our customers. Our international pipeline operations include access between our U.S. based systems and Canada.

Our Merchant Energy segment is involved in a broad range of energy-related activities including asset ownership and marketing and trading. We buy, sell and trade crude oil, refined products, coal 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 18 facilities in 8 countries. The three refineries we operate have the capacity to process approximately 438 MBbls of crude oil per day and produce a variety of petroleum products. We also produce agricultural and industrial chemicals at five facilities in the U.S. Our coal mining operations produce high-quality, bituminous coal with reserves in Kentucky, Virginia and West Virginia.

Our Production segment leases approximately 2 million net acres in 14 states, including Colorado, Texas, Utah, West Virginia and Wyoming, and in the Gulf of Mexico. We also have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia. During 2001, daily equivalent natural gas production was 1.2 Bcfe/d, and our reserves at December 31, 2001, were approximately 4.3 Tcfe.

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 4,000 natural gas wells with approximately 4,500 miles of natural gas gathering and natural gas liquids pipelines, and 14 natural gas processing, treating and fractionation facilities located in some of the most active production areas in the U.S., including east and south Texas, Louisiana and the Rocky Mountains.

## Pipelines Segment

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through three wholly owned and three partially owned interstate transmission systems along with five underground natural gas storage facilities. The tables below detail our wholly owned and partially owned interstate transmission systems:

### Wholly Owned Interstate Transmission Systems

| Transmission System | Supply and Market Region | Miles of Pipeline | Design Capacity | Average Throughput[(1)] | | | Storage Capacity |
|---|---|---|---|---|---|---|---|
| | | | | 2001 | 2000 | 1999 | |
| | | | (MMcf/d) | (BBtu/d) | | | (Bcf) |
| ANR Pipeline (ANR) | Extends from Texas, Oklahoma, Louisiana and the Gulf of Mexico to the Midwest and northeast regions of the U.S., including Detroit, Chicago and Milwaukee. | 10,600 | 6,394 | 3,776 | 3,807 | 3,515 | 202 |
| Colorado Interstate Gas (CIG) | Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and various interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest. | 4,600 | 2,928 | 1,448 | 1,383 | 1,301 | 29 |
| Wyoming Interstate (WIC) | Extends from western Wyoming and the Powder River Basin to the CIG-Trailblazer interconnect near Cheyenne, Wyoming on the 800-mile Trailblazer system and into other interstate and intrastate pipelines. | 600 | 1,860 | 1,017 | 832 | 657 | — |

(1) Includes throughput transported on behalf of affiliates.

## Partially Owned Interstate Transmission Systems

| Transmission System | Supply and Market Region | Ownership Interest | Miles of Pipeline | Design Capacity[1] | Average Throughput[1] 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|---|
| | | (Percent) | | (MMcf/d) | (BBtu/d) | | |
| Alliance Pipeline[2] | Extends from western Canada to Chicago. | 14 | 2,345 | 1,537 | 1,479 | 105 | — |
| Great Lakes Gas Transmission | Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan. | 50 | 2,100 | 2,895 | 2,224 | 2,477 | 2,602 |
| Overthrust Pipeline Company | Extends from the Whitney Canyon area near the Utah-Wyoming border to Rock Springs, Wyoming. | 10 | 88 | 227 | 87 | 85 | 140 |

(1) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.
(2) The Alliance pipeline project commenced operations in the fourth quarter of 2000.

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage facilities:

## Underground Natural Gas Storage Facilities

| Storage Facility | Ownership Interest | Storage Capacity[1] | Location |
|---|---|---|---|
| | (Percent) | (Bcf) | |
| ANR Storage | 100 | 56 | Michigan |
| Blue Lake Gas Storage | 75 | 47 | Michigan |
| Eaton Rapids Gas Storage | 50 | 13 | Michigan |
| Steuben Gas Storage | 50 | 6 | New York |
| Young Gas Storage | 48 | 5 | Colorado |

(1) Includes a total of 75 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

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

| Transmission System | Project | Capacity | Description[1] | Anticipated Completion Date |
|---|---|---|---|---|
| | | (MMcf/d) | | |
| ANR | PG&E Badger | 210 | A lateral pipeline to supply natural gas to a PG&E facility located in southeast Wisconsin. | May 2004 |
| CIG | Front Range Expansion | 283 | Installation of compression and pipeline looping to increase deliverability along the Colorado Front Range market area. | December 2002 |

(1) Pipeline looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases the transmission system's capacity.

*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 each system provides services to its 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 facilities have tariffs established through filings with the FERC that have a variety of terms and conditions, each of which affects their operations and their ability to recover fees for the services they provide. Generally, changes to these fees or terms of service can only be implemented upon approval by the FERC.

In Canada, our pipeline operating activities are regulated by the National Energy Board. Similar to the FERC, the National Energy Board governs tariffs and rates, and the construction and operation of natural gas pipelines in Canada.

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 of our systems 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 and storage facilities by the U.S. Department of Transportation. Additionally, we are subject to similar safety requirements from the U.S. Department of Labor's Occupational Safety and Health Administration related to our processing plants. 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 13.

*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. The following table details our markets and competition on each of our wholly owned pipeline systems:

| Transmission System | Customer Information(1) | Contract Information | Competition |
|---|---|---|---|
| ANR | Approximately 250 firm and interruptible customers<br><br>Major Customer:<br>Wisconsin Gas Company (772 BBtu/d) | Approximately 600 firm contracts<br>Contracted capacity: 97%<br>Remaining contract term: 5 months to 23 years<br>Average remaining contract term: 5 years<br><br>Contract terms expire in 2002-2008. | In Wisconsin and Michigan, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast markets, ANR competes with other interstate pipelines serving electric generation and local distribution companies. Also, Wisconsin Gas is a sponsor of the proposed Guardian Pipeline, which is expected to be in service by the spring of 2002, and will directly compete for a portion of the markets served by ANR's expiring capacity. |
| CIG | Approximately 165 firm and interruptible customers<br><br>Major Customer:<br>Public Service Company of Colorado (1,231 BBtu/d) | Approximately 160 firm contracts<br>Contracted capacity: 100%<br>Remaining contract term: 2 months to 23 years<br>Average remaining contract term: 7 years<br><br>Contract term expires in 2007. | In CIG's "on-system" market, competition comes from local supply in the Denver-Julesburg basin, from an intrastate pipeline directly serving Denver and from off-system shippers who can deliver their gas in that market, supplanting CIG transportation for on-system customers. In its "off-system" market, CIG faces competition in its supply areas from competitors who can ship natural gas to the Midwest, California, the Southwest and the Pacific Northwest. |
| WIC | Approximately 45 firm and interruptible customers<br><br>Major Customers:<br>Colorado Interstate Gas Company (247 BBtu/d)<br>Western Gas Resources (206 BBtu/d)<br>Williams Energy Marketing and Trading (177 BBtu/d) | Approximately 50 firm contracts<br>Contracted capacity: 100%<br>Remaining contract term: 9 months to 18 years<br>Average remaining contract term: 6 years<br><br>Contract terms expire in 2003-2007.<br>Contract terms expire in 2003-2013.<br>Contract terms expire in 2003-2013. | WIC competes with eight interstate pipelines and one intrastate pipeline for supply access. Additionally, WIC's two lines feed into the Trailblazer system going east, the CIG system going south and other interstate and intrastate pipelines connected at the CIG-Trailblazer interconnect. |

(1) Includes natural gas producers, marketers, end users and other natural gas transmission, distribution and electric generation companies.

The ability of our pipeline systems to extend their existing contracts or re-market expiring capacity with their 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 every attempt is made to re-negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under their tariffs, our pipelines must at times discount their 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 and marketing and trading.

### Asset Ownership

Merchant Energy's Asset Ownership activities include ownership interests in domestic and international power generation, refining and chemicals operations and coal mining.

*Power Generation.* We own or have interests in 18 power plants in 8 countries. These plants represent 4,242 gross megawatts of generating capacity, 71 percent of which is sold under power purchase or tolling agreements with terms in excess of five years. Of these facilities, 39 percent are natural gas fired and 61 percent are a combination of coal, natural gas liquids and other fuels. Through an affiliate, we have invested in two U.S. power generation facilities with a total generating capacity of approximately 300 gross megawatts. Internationally, our focus is on building energy infrastructure in emerging markets. Our primary areas of focus include Asia and Central America.

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 Megawatts[(1)] |
|---|---|---|---|---|
| United States | | | | |
| East Coast | Operational | 4 | 408 | 408 |
| Central | Operational | 1 | 1,500 | 653 |
| | Under Construction | 1 | 544 | 272 |
| Asia | Operational | 6 | 593 | 469 |
| Central America | Operational | 5 | 1,148 | 408 |
| | Under Construction | 1 | 49 | 10 |
| Total | | 18 | 4,242 | 2,220 |

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

*Refining and Chemicals.* Our Refining and Chemicals business: (i) owns or has interests in four crude oil refineries and five chemical production facilities; (ii) has petroleum terminalling and related marketing operations; and (iii) has blending and packaging operations that produce and distribute a variety of lubricants and automotive related products. The refineries we operate have a throughput capability of approximately 438 MBbls of crude oil per day to produce a variety of gasolines, diesel fuels, asphalt, industrial fuels and other products. Our chemical facilities have a production capability of 3,800 tons per day and produce various industrial and agricultural products.

In 2001, our refineries operated at 70 percent of their average combined capacity and at 93 percent in each of 2000 and 1999. The aggregate sales volumes at our wholly owned refineries were approximately 131 MMBbls in 2001, 182 MMBbls in 2000 and 171 MMBbls in 1999. Of our total refinery sales in 2001, 39 percent was gasoline, 39 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 22 percent was heavy industrial fuels and other products.

The following table presents average daily throughput and storage capacity at our wholly owned refineries at December 31:

| Refinery | Location | Average Daily Throughput 2001 | 2000 | 1999 | At December 31, 2001 Daily Capacity | Storage Capacity |
|---|---|---|---|---|---|---|
| | | (In MBbls) | | | | |
| Aruba | Aruba | 178 | 229 | 195 | 280 | 15,258 |
| Eagle Point | Westville, New Jersey | 118 | 143 | 143 | 140 | 8,854 |
| Corpus Christi[(1)] | Corpus Christi, Texas | 38 | 99 | 100 | — | — |
| Mobile | Mobile, Alabama | 10 | 12 | 13 | 18 | 600 |
| Total | | 344 | 483 | 451 | 438 | 24,712 |

(1) In June 2001, we leased our Corpus Christi refinery to Valero Energy Corporation. The lease is for 20 years, and Valero has an option to purchase the refinery beginning in 2003. These volumes only reflect those produced prior to our lease of the facilities.

Our chemical plants produce agricultural fertilizers, gasoline additives and other industrial products from facilities in Nevada, Oregon, Texas and Wyoming. The following table presents sales volumes from our wholly owned chemical facilities for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (MTons) | |
| Industrial | 492 | 547 | 608 |
| Agricultural | 378 | 389 | 326 |
| Gasoline additives | 173 | 214 | 209 |
| Total | 1,043 | 1,150 | 1,143 |

*Coal Mining.* Our Coal mining business controls reserves totaling 524 million recoverable tons and produces high-quality bituminous coal from reserves in Kentucky, Virginia and West Virginia. The extracted coal is primarily sold under long-term contracts to power generation facilities in the eastern U.S. During the year ended December 31, 2001, coal production totaled 11.5 million tons.

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

**Marketing and Trading**

Merchant Energy's marketing and trading groups trade crude oil, refined products, coal and other energy commodities and related financial instruments. Through these activities, these groups attempt to optimize the value of the segment's asset portfolio.

Prior to October 2000, we conducted our natural gas and power marketing and trading activities through Engage Energy US, L.P. and Engage Energy Canada, L.P., a joint venture between us and Westcoast Energy Inc., a Canadian natural gas company. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed the U.S. portion of Engage's trading activities. In February 2001, we transferred our natural gas and power trading activities in the U.S. to El Paso Merchant Energy, our affiliate and a subsidiary of El Paso, and we stopped natural gas and power trading activities.

Detailed below is the marketed and traded energy commodity volumes for each of the three years ended December 31:

| Volumes | 2001 | 2000 | 1999 |
|---|---|---|---|
| Physical | | | |
| Natural gas (BBtue/d) | 3,457 | 3,457 | — |
| Power (MMWh) | 407 | 1,923 | — |
| Crude oil and refined products (MBbls) | 679,489 | 660,062 | 659,945 |
| Coal (MTons) | 10,343 | 9,834 | 8,980 |
| Financial settlements (BBtue/d) | 89,187 | 52,451 | 45,136 |

*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 and refining, chemical and petroleum 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 3,600 suppliers and over 5,800 customers around the world.

Merchant Energy's trading, marketing, refining, chemicals and power 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;
- independent energy marketers and power producers with varying scopes of operations and financial resources; and
- independent refining and chemical companies.

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.

**Production Segment**

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., we have onshore properties in 14 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

Production primarily sells its natural gas to third parties through an affiliate at spot-market prices. It sells its natural gas liquids at market prices under monthly or long-term contracts and its oil production at posted prices, subject to adjustments for gravity and transportation. Production engages in hedging activities on its natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. During 2001, approximately 73 percent of the segment's overall production was hedged at fixed prices.

Strategically, Production emphasizes disciplined investment criteria and manages its existing production portfolio to maximize volumes and minimize costs. It employs geophysical technology and seismic data processing to identify economic hydrocarbon reserves. Production's deep drilling capabilities and hydraulic fracturing technology allow it to optimize production with high-rate completions at attractive reserve replacement costs. Production maintains an active drilling program that capitalizes on its land and seismic holdings. It also acquires production properties subject to acceptable investment return criteria.

*Natural Gas and Oil Reserves*

The table below details Production's proved reserves at December 31, 2001. Information in this table is based on the reserve report dated January 1, 2002, prepared internally by Production and reviewed by Huddleston & Co., Inc. This information agrees with estimates of reserves filed with other federal agencies except for differences of less than 5 percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. These reserves include 124,158 MMcfe of production delivery commitments under financing arrangements that extend through 2005. Total proved reserves on the fields with this dedicated production were 1,981,239 MMcfe.

| | Net Proved Reserves[1] | | |
|---|---|---|---|
| | Natural Gas (MMcf) | Liquids[2] (MBbls) | Total (MMcfe) |
| **Production** | | | |
| United States | | | |
| Producing | 1,236,223 | 51,817 | 1,547,126 |
| Non-Producing | 376,918 | 10,889 | 442,252 |
| Undeveloped | 1,744,906 | 43,958 | 2,008,654 |
| Total Proved | 3,358,047 | 106,664 | 3,998,032 |
| Canada | | | |
| Producing | 107,843 | 6,580 | 147,323 |
| Non-Producing | 30,255 | 761 | 34,821 |
| Undeveloped | 48,213 | 3,541 | 69,459 |
| Total Proved | 186,311 | 10,882 | 251,603 |
| Other Countries[3] | | | |
| Producing | — | — | — |
| Non-Producing | — | — | — |
| Undeveloped | 40,130 | 7,771 | 86,756 |
| Total Proved | 40,130 | 7,771 | 86,756 |
| Worldwide | | | |
| Producing | 1,344,066 | 58,397 | 1,694,449 |
| Non-Producing | 407,173 | 11,650 | 477,073 |
| Undeveloped | 1,833,249 | 55,270 | 2,164,869 |
| Total Proved | 3,584,488 | 125,317 | 4,336,391 |
| **Natural Gas Systems[4]** | | | |
| Producing | 182,857 | 97 | 183,439 |
| Non-Producing | — | — | — |
| Undeveloped | — | — | — |
| Total Proved | 182,857 | 97 | 183,439 |

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.
(3) Includes international operations in Brazil and Indonesia.
(4) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries. These reserves are located in the U.S.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of Production. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties owned by Production declines as reserves are depleted. Except to the extent Production conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the proved reserves of Production will decline as reserves are produced.

For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, Note 19.

*Wells and Acreage*

The following table details Production's gross and net interest in developed and undeveloped onshore, offshore, coal seam and international acreage at December 31, 2001. Any acreage in which Production's interest is limited to owned royalty, overriding royalty and other similar interests are excluded.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Production | | | | | | |
| United States | | | | | | |
| Onshore | 1,727,082 | 921,212 | 1,078,670 | 671,949 | 2,805,752 | 1,593,161 |
| Offshore | 418,644 | 256,628 | 386,746 | 369,689 | 805,390 | 626,317 |
| Coal Seam | 27,488 | 7,449 | 1,040 | 22 | 28,528 | 7,471 |
| Total | 2,173,214 | 1,185,289 | 1,466,456 | 1,041,660 | 3,639,670 | 2,226,949 |
| International | | | | | | |
| Australia | — | — | 1,770,364 | 613,600 | 1,770,364 | 613,600 |
| Bolivia | — | — | 154,840 | 15,484 | 154,840 | 15,484 |
| Brazil | — | — | 5,570,315 | 4,089,259 | 5,570,315 | 4,089,259 |
| Canada | 838,300 | 615,373 | 290,370 | 130,528 | 1,128,670 | 745,901 |
| Hungary | — | — | 568,100 | 568,100 | 568,100 | 568,100 |
| Indonesia | — | — | 1,373,691 | 442,606 | 1,373,691 | 442,606 |
| Total | 838,300 | 615,373 | 9,727,680 | 5,859,577 | 10,565,980 | 6,474,950 |
| Worldwide Total | 3,011,514 | 1,800,662 | 11,194,136 | 6,901,237 | 14,205,650 | 8,701,899 |
| Natural Gas Systems | | | | | | |
| Domestic Onshore | 262,474 | 259,276 | — | — | 262,474 | 259,276 |
| Total | 3,273,988 | 2,059,938 | 11,194,136 | 6,901,237 | 14,468,124 | 8,961,175 |

The U.S. domestic net developed acreage is concentrated primarily in Texas (28 percent), Utah (25 percent), the Gulf of Mexico (18 percent), Colorado (11 percent), West Virginia (9 percent) and Wyoming (7 percent). Approximately 16 percent, 27 percent and 23 percent of our total U.S. net undeveloped acreage is under leases that have minimum remaining primary terms expiring in 2002, 2003 and 2004.

The following table details Production's working interests in onshore, offshore, coal seam and international natural gas and oil wells at December 31, 2001:

| | Productive Natural Gas Wells | | Productive Oil Wells | | Total Productive Wells | | Number of Wells Being Drilled | |
|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Production | | | | | | | | |
| United States | | | | | | | | |
| Onshore | 2,479 | 1,962 | 469 | 307 | 2,948 | 2,269 | 35 | 26 |
| Offshore | 238 | 125 | 40 | 25 | 278 | 150 | — | — |
| Coal Seam | 278 | 61 | — | — | 278 | 61 | — | — |
| Total | 2,995 | 2,148 | 509 | 332 | 3,504 | 2,480 | 35 | 26 |
| International | | | | | | | | |
| Canada | 305 | 178 | 264 | 122 | 569 | 300 | 7 | 4 |
| Worldwide Total | 3,300 | 2,326 | 773 | 454 | 4,073 | 2,780 | 42 | 30 |
| Natural Gas Systems | | | | | | | | |
| Domestic Onshore | 879 | 806 | 9 | 8 | 888 | 814 | — | — |
| Total | 4,179 | 3,132 | 782 | 462 | 4,961 | 3,594 | 42 | 30 |

The following table details Production's exploratory and development wells drilled during the years 1999 through 2001:

| | Net Exploratory Wells Drilled | | | Net Development Wells Drilled | | |
|---|---|---|---|---|---|---|
| | 2001 | 2000 | 1999 | 2001 | 2000 | 1999 |
| Production | | | | | | |
| United States | | | | | | |
| Productive | 9 | 10 | 7 | 183 | 224 | 181 |
| Dry | 3 | 7 | 5 | 19 | 14 | 1 |
| Total | 12 | 17 | 12 | 202 | 238 | 182 |
| Canada | | | | | | |
| Productive | 12 | 3 | 5 | 47 | 10 | 2 |
| Dry | 12 | 3 | — | 26 | 1 | 2 |
| Total | 24 | 6 | 5 | 73 | 11 | 4 |
| Other Countries[1] | | | | | | |
| Productive | — | — | — | — | — | — |
| Dry | 6 | 1 | — | 1 | — | — |
| Total | 6 | 1 | — | 1 | — | — |
| Worldwide | | | | | | |
| Productive | 21 | 13 | 12 | 230 | 234 | 183 |
| Dry | 21 | 11 | 5 | 46 | 15 | 3 |
| Total | 42 | 24 | 17 | 276 | 249 | 186 |
| Natural Gas Systems | | | | | | |
| Productive | — | — | — | 17 | 1 | 13 |
| Dry | — | — | — | — | — | — |
| Total | — | — | — | 17 | 1 | 13 |
| Total | 42 | 24 | 17 | 293 | 250 | 199 |

(1) Includes international operations in Australia, Brazil and Indonesia.

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

*Net Production, Unit Prices and Production Costs*

The following table details Production's net production volumes, average sales prices received and average production costs associated with the sale of natural gas and oil for each of the three years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| Production | | | |
| United States | | | |
| Net Production: | | | |
| Natural Gas (Bcf) | 373 | 328 | 231 |
| Oil, Condensate and Liquids (MMBbls) | 8 | 6 | 4 |
| Total (Bcfe) | 422 | 367 | 257 |
| Average Sales Price[1]: | | | |
| Natural Gas ($/Mcf) | $ 4.03 | $ 2.83 | $ 2.17 |
| Oil, Condensate and Liquids ($/Bbl) | $22.43 | $24.86 | $14.48 |
| Average Production Cost ($/Mcfe)[2] | $ 0.50 | $ 0.45 | $ 0.40 |
| Canada | | | |
| Net Production: | | | |
| Natural Gas (Bcf) | 13 | 1 | — |
| Oil, Condensate and Liquids (MMBbls) | 1 | — | — |
| Total (Bcfe) | 17 | 1 | — |
| Average Sales Price[1]: | | | |
| Natural Gas ($/Mcf) | $ 2.68 | $ 4.09 | $ — |
| Oil, Condensate and Liquids ($/Bbl) | $18.26 | $ — | $ — |
| Average Production Cost ($/Mcfe)[2] | $ 0.74 | $ 0.66 | $ — |
| Worldwide | | | |
| Net Production: | | | |
| Natural Gas (Bcf) | 386 | 329 | 231 |
| Oil, Condensate and Liquids (MMBbls) | 9 | 6 | 4 |
| Total (Bcfe) | 439 | 368 | 257 |
| Average Sales Price[1]: | | | |
| Natural Gas ($/Mcf) | $ 3.99 | $ 2.83 | $ 2.17 |
| Oil, Condensate and Liquids ($/Bbl) | $22.16 | $24.86 | $14.48 |
| Average Production Cost ($/Mcfe)[2] | $ 0.51 | $ 0.45 | $ 0.40 |
| Natural Gas Systems | | | |
| Net Production: | | | |
| Natural Gas (Bcf) | 30 | 33 | 36 |
| Average Sales Price[1]: | | | |
| Natural Gas ($/Mcf) | $ 3.00 | $ 2.06 | $ 1.38 |

(1) Includes costs associated with transporting volumes sold and the effects of our hedging program.

(2) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

*Acquisition, Development and Exploration Expenditures*

The following table details information regarding Production's costs incurred in its development, exploration and acquisition activities for each of the three years ended December 31:

| Production | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| United States | | | |
| Acquisition Costs: | | | |
| Proved | $ 87 | $ 127 | $ 154 |
| Unproved | 33 | 130 | 142 |
| Development Costs | 1,026 | 960 | 588 |
| Exploration Costs: | | | |
| Delay Rentals | 9 | 6 | 4 |
| Seismic Acquisition and Reprocessing | 10 | 51 | 50 |
| Drilling | 91 | 136 | 96 |
| Total | $1,256 | $1,410 | $1,034 |
| Canada | | | |
| Acquisition Costs: | | | |
| Proved | $ 232 | $ 3 | $ — |
| Unproved | 16 | 6 | 10 |
| Development Costs | 105 | 69 | 5 |
| Exploration Costs: | | | |
| Delay Rentals | — | — | — |
| Seismic Acquisition and Reprocessing | 10 | 10 | 5 |
| Drilling | 9 | 32 | 6 |
| Total | $ 372 | $ 120 | $ 26 |
| Other Countries[1] | | | |
| Acquisition Costs: | | | |
| Proved | $ — | $ — | $ — |
| Unproved | 26 | — | — |
| Development Costs | 14 | — | — |
| Exploration Costs: | | | |
| Delay Rentals | — | — | — |
| Seismic Acquisition and Reprocessing | 6 | 18 | 5 |
| Drilling | 61 | 14 | 2 |
| Total | $ 107 | $ 32 | $ 7 |
| Worldwide | | | |
| Acquisition Costs: | | | |
| Proved | $ 319 | $ 130 | $ 154 |
| Unproved | 75 | 136 | 152 |
| Development Costs | 1,145 | 1,029 | 593 |
| Exploration Costs: | | | |
| Delay Rentals | 9 | 6 | 4 |
| Seismic Acquisition and Reprocessing | 26 | 79 | 60 |
| Drilling | 161 | 182 | 104 |
| Total | $1,735 | $1,562 | $1,067 |

(1) Includes international operations in Australia, Brazil, Hungary and Indonesia.

*Regulatory and Operating Environment*

Production's natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world in which Production does business. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. Production is also subject to governmental safety regulations in the jurisdictions in which it operates.

Production's U.S. operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of pollution resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Production's international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international laws and regulations relating to the protection of the environment affect Production's natural gas and oil operations through their effect on the construction and operation of facilities, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in compliance with the applicable requirements. In addition, we maintain insurance on behalf of Production for sudden and accidental spills and oil pollution liability.

Production's business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage on behalf of Production with respect to potential losses resulting from these operating hazards. However, insurance is not available to Production against all operational risks.

*Markets and Competition*

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Production's competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and quality of service. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

## 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 Rocky Mountain region, referred to as the Western Division; in the producing regions of east and south Texas, referred to as the Central Division; and in Louisiana, referred to as the Eastern Division.

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 | 100 | 2,639 | 319 | 317 | 326 | 182 |
| Western Division | 100 | 1,820 | 435 | 335 | 293 | 424 |

(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.

| Processing Plants | Ownership Interest | Inlet Capacity[1] | Average Inlet Volume[1] 2001 | 2000 | 1999 | Average Natural Gas Liquids Sales[1] 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|---|---|
| | (Percent) | (MMcfe/d) | | (BBtue/d) | | | (Mgal/d) | |
| Eastern Division[2] | 100 | 2,980 | 1,738 | 1,606 | 253 | 1,619 | 1,744 | 331 |
| Western Division | 100 | 204 | 107 | 105 | 67 | 207 | 201 | 175 |
| Central Division | 100 | 160 | 135 | 143 | 156 | 343 | 375 | 396 |
| Mobile Bay[3] | 42 | 441 | 146 | 338 | 115 | — | — | — |
| Aux Sable[4] | 14 | 302 | 192 | — | — | — | — | — |

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

(2) Reflects the acquisition of TransCanada Gas Processing U.S.A. in December 1999.

(3) Mobile Bay went in service in April 1999.

(4) Aux Sable went in service in December 2000.

*Regulatory Environment*

We are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and the National Environmental Policy Act. We have a continuing program of inspection designed to keep all of the facilities in compliance with pollution control and pipeline safety requirements, and we believe 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 or 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 13, and is incorporated herein by reference.

## Employees

As of March 28, 2002, we had approximately 5,000 full-time employees, of which approximately 650 are subject to collective bargaining agreements.

## ITEM 2. PROPERTIES

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

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 such 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 13, and is incorporated herein by reference.

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

Item 4, Submission of Matters to a Vote of Security Holders, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

## PART II

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

On January 29, 2001, we merged with El Paso. As a result of the merger and the conversion of all of our outstanding common stock and Class A common stock into El Paso common stock, all of our common stock is owned by El Paso.

### ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

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

The information required by this Item is presented in a reduced disclosure format permitted by General Instruction I to Form 10-K. The Notes to Consolidated Financial Statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies.

*Merger with El Paso Corporation*

In January 2001, we merged with El Paso. El Paso accounted for the merger as a pooling of interests and converted each share of our common stock and Class A common stock on a tax-free basis into 1.23 shares of El Paso common stock. El Paso also exchanged our outstanding convertible preferred stock for its common stock on the same basis as if the preferred stock had been converted into our common stock immediately prior to the merger. El Paso issued a total of 271 million shares, including 4 million shares issued to holders of our stock options.

In connection with a Federal Trade Commission (FTC) order related to this merger, in 2001 we sold our Gulfstream pipeline project and our investments in the Empire State, Stingray, U-T Offshore and Iroquois pipeline systems. Proceeds from these sales were approximately $184 million, and we recognized an extraordinary loss of $11 million, net of income taxes of $5 million, on these transactions.

*Merger-Related Costs, Asset Impairments and Other Charges*

Below are the charges incurred that had a significant impact on our results of operations, financial position and cash flows for the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Merger-related costs | $ 977 | $13 |
| Asset impairments | 9 | 21 |
| Total merger-related costs and asset impairments | 986 | 34 |
| Changes in accounting estimates | 317 | — |
| | 1,303 | 34 |
| Ceiling test charges | 115 | — |
| | $1,418 | $34 |

*Merger-Related Costs.* Our merger-related costs relate to our merger with El Paso and consisted of the following for the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Employee severance, retention and transition costs | $586 | $— |
| Transaction costs | 7 | 13 |
| Business and operational integration costs | 122 | — |
| Merger-related asset impairments | 162 | — |
| Other | 100 | — |
| | $977 | $13 |

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 our merger-related workforce reduction and consolidation. Following the merger, El Paso completed an employee restructuring across all of our operating segments, resulting in the reduction of approximately 3,200 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The pension and post-retirement benefits were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid.

Also included in the 2001 employee severance, retention and transition costs, was a charge of $278 million resulting from the issuance of approximately 4 million shares of El Paso common stock on the merger date in exchange for the fair value of our employees' and directors' stock options.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete the merger. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under the El Paso combined operating strategy and incremental fees under software and seismic license agreements. Also included in the 2001 charges are approximately $121 million in estimated lease related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas. These charges were accrued at the time we completed our relocations and closed this office. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following the merger. These charges occurred in our Merchant Energy, Production and Pipelines segments, and all of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on this change in operating strategy.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with El Paso and other miscellaneous charges. These items were expensed in the period in which they were incurred.

*Asset Impairments.* The 2001 asset impairment charges resulted from the write-down of Merchant Energy's Corpus Christi refinery and related assets as a result of our lease of these assets to Valero in June 2001. The 2000 charges consisted of the impairment of coal mining and refining assets in our Merchant

Energy segment. These impairments 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 operation has been suspended.

*Changes in Accounting Estimates.* Our 2001 changes in accounting estimates consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $38 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. These changes were primarily the result of several events that occurred as part of and following our merger with El Paso, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. These charges are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001, by approximately $241 million.

*Ceiling Test Charges.* Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. During the third quarter of 2001, capitalized costs exceeded this ceiling limit by $115 million, including $87 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool. These charges were based on the November 1, 2001 daily posted oil and natural gas sales prices, adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. This non-cash write-down is included in our income statement as ceiling test charges.

We use financial instruments to hedge against volatility of natural gas and oil prices. The impact of these hedges was considered in the determination of our ceiling test charge during 2001 and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our 2001 ceiling test charge, the charge would not have materially changed since we do not significantly hedge our international production activities.

Also as mentioned above, our 2001 charge was computed based on daily posted prices on November 1, 2001. Had we computed this charge based on the daily oil and natural gas prices as of September 30, 2001, the charge would have been approximately $255 million, including approximately $227 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool, including the impact on future cash flows of our hedging program. Had the impact of our hedging program been excluded, the charges would have been approximately the same for our international full cost pools and production operations, but we would have incurred an additional charge of approximately $830 million related to our U.S. full cost pool.

## Results of Operations

For the year ended December 31, 2001, we had a net loss of $188 million versus net income of $654 million for the year ended December 31, 2000. The 2001 loss was a result of the charges discussed above which totaled $1,418 million, or $1,181 million after taxes. We also recorded net extraordinary losses totaling $11 million, net of income taxes, as a result of FTC ordered sales of our Gulfstream pipeline project and our investments in the Empire State, Stingray, U-T Offshore and Iroquois pipeline systems. For the year ended December 31, 2000, merger-related charges were $34 million, or $24 million net of income taxes. Net income, excluding the after-tax effects of these charges and extraordinary items, would have been $1,004 million in 2001 versus $678 million in 2000.

## Segment Results

Our four segments: Pipelines, Merchant Energy, Production and Field Services are strategic business units that offer a variety of different energy products and services, each requiring different technology and marketing strategies. We evaluate our segment performance based on EBIT. Our historical segments (natural gas systems; refining, marketing and chemicals; exploration and production; power; and coal) have been restated and included in the segments in which these businesses were managed and operated following the merger. All prior periods have been restated to reflect this presentation. The results presented in this analysis are not necessarily indicative of the results that 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 trading and refining portions of Merchant Energy and for the Field Services segment. 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 15.

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

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Pipelines | $ 292 | $ 500 |
| Merchant Energy | (11) | 366 |
| Production | 791 | 413 |
| Field Services | 71 | 111 |
| Segment EBIT | 1,143 | 1,390 |
| Corporate and other, net | (698) | 78 |
| Consolidated EBIT | $ 445 | $1,468 |

### Pipelines

Our Pipelines segment operates our interstate pipeline businesses. Each pipeline system operates under a separate tariff that governs its 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 system to system, 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 the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volume amounts) | |
| Operating revenues | $ 1,052 | $1,045 |
| Operating expenses | (860) | (657) |
| Other income | 100 | 112 |
| EBIT | $ 292 | $ 500 |
| Throughput volumes (BBtu/d)[1] | 7,443 | 7,167 |

[1] Throughput volumes exclude those related to pipeline systems sold in connection with FTC orders related or our merger with El Paso including the Empire State and Iroquois pipeline investments. Throughput volumes also exclude intrasegment activities.

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

Operating revenues for the year ended December 31, 2001, were $7 million higher than the same period in 2000. The increase was due to the impact of completed system expansions and new storage and transportation contracts during 2001, higher realized prices on segment-owned production and on sales of natural gas purchased from the Dakota gasification facility. Also contributing to the increase was increased fuel recoveries due to higher natural gas prices and increased fuel efficiencies. Partially offsetting the increase was the favorable resolution of natural gas price-related contingencies in 2000, lower 2001 sales of base gas from abandoned storage fields and the favorable resolution of regulatory issues in 2000.

Operating expenses for the year ended December 31, 2001, were $203 million higher than the same period in 2000. The increase was primarily the result of merger-related costs and other charges in 2001 discussed previously, along with the impact of higher natural gas prices on system fuel costs and gas purchases at the Dakota gasification facility. Also contributing to the increase were higher corporate allocations. Partially offsetting the increase was lower purchase gas costs due to the net impact of a natural gas imbalance revaluation in 2001 as a result of falling gas prices during the second half of the year and accruals for the replacement of system balancing gas in 2000.

Other income for the year ended December 31, 2001, was $12 million lower than the same period in 2000. The decrease was due to lower equity income in 2001 on the ANR Storage project and the sales of our investments in the Empire State and Iroquois pipeline systems in the first and second quarters of 2001. Also contributing to the decrease were higher expenses in 2001 related to expansion and development projects and a tax refund in the fourth quarter of 2000. Partially offsetting the decrease were increased earnings from our investments in the Alliance Pipeline project and the Great Lakes Gas Transmission project.

## Merchant Energy

Our Merchant Energy segment is involved in asset ownership and marketing and trading. The markets served by Merchant Energy are highly competitive and influenced directly or indirectly by energy market economics.

*Asset Ownership*

Merchant Energy's asset ownership activities include domestic and international power plants and refining, chemical and coal mining operations. In its power asset business, Merchant Energy owns or has interests in 18 plants in 8 countries. Merchant Energy also has refining, chemical and coal mining operations. Results from Merchant Energy's refining and chemical operations are highly dependent on margin differentials between feedstocks, primarily crude oil and other petroleum products and market prices of the products produced, both of which can be highly volatile. In our coal mining business, results are driven by productivity of our mining operations along with the market prices of the coal produced.

*Marketing and Trading*

Merchant Energy's marketing and trading activities trade crude oil, refined products, coal and other energy commodities and related financial instruments. At December 31, 2001, the fair value of our trading-related price risk management activities was a net unrealized loss of $23 million, and total margins generated from these activities during 2001 were $15 million.

Prior to October 2000, we conducted our natural gas and power marketing and trading activities through Engage Energy U.S., L.P. and Engage Canada, L.P., a joint venture between us and Westcoast Energy Inc., a major Canadian natural gas company. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed Engage's U.S. trading activities. In February 2001, we transferred these activities to a subsidiary of El Paso in exchange for a 22 percent interest in El Paso Merchant Energy, L.P.

Below are Merchant Energy's operating results and traded volumes (excluding intrasegment transactions) and an analysis of these results for the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volumes) | |
| Operating results: | | |
| Trading and refining gross margin | $ 865 | $ 952 |
| Operating and other revenues | 321 | 330 |
| Operating expenses | (1,396) | (1,164) |
| Other income | 199 | 248 |
| EBIT | $ (11) | $ 366 |
| Volumes (Excludes intrasegment transactions): | | |
| Physical | | |
| Natural gas (BBtue/d) | 3,457 | 3,457 |
| Power (MMWh) | 407 | 1,923 |
| Crude oil and refined products (MBbls) | 679,489 | 660,062 |
| Coal (MTons) | 10,343 | 9,834 |
| Financial Settlements (BBtue/d) | 89,187 | 52,451 |

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

Trading and refining gross margin consists of revenues from our refineries and commodity trading activities, less the costs of the feedstocks used in the refining process and the costs of commodities sold. For the year ended December 31, 2001, our trading and refining gross margin was $87 million lower than the same period in 2000. This decrease was primarily due to lower refining margins resulting from a fire at our Aruba facility in April 2001, the lease of our Corpus Christi refinery and related assets to Valero in June 2001, lower margins in heavy crude based refined products and lower margins and throughput at the Eagle Point refinery as a result of decreased demand for jet fuel following the events of September 11, 2001. The decrease in refining margins resulting from the fire at our Aruba facility was largely offset by the collection of business interruption insurance proceeds.

Operating and other revenues consist of revenues from consolidated domestic power generation facilities and coal operations. For the year ended December 31, 2001, operating and other revenues were $9 million lower than the same period in 2000. The decrease resulted primarily from the transfer of power index swaps on our Fulton and Rensselaer power facilities to a subsidiary of El Paso in February 2001, partially offset by increased coal volumes.

Operating expenses for the year ended in December 31, 2001, were $232 million higher than the same period in 2000. The increase was primarily a result of merger-related costs and asset impairments associated with combining operations and implementing our combined strategy with El Paso, and changes in our estimates of environmental remediation costs, legal obligations and spare parts inventory usability. The increase also resulted from higher fuel costs at our refineries due to higher natural gas prices. These increases were partially offset by lower operating expenses resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001.

Other income for the year ended December 31, 2001, was $49 million lower than the same period in 2000. The decrease was the result of the sale of our interest in a Guatemala power project in the first quarter of 2000, lower earnings from the Javelina project in 2001 due to lower NGL prices and higher gas costs and a gain recorded in 2000 from the sale of 49 percent of our Montreal petrochemical facility. These decreases were partially offset by higher equity earnings from a power facility investment due to the completion of a power purchase contract restructuring in the fourth quarter 2001.

**Production**

Production's operating results are driven by a variety of factors including its ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at the lowest cost level possible. In 2002, Production expects to continue an active onshore and offshore development drilling program to capitalize on its land and seismic holdings. The estimated capital expenditures for Production in 2002 are $1.2 billion. Production will continue to pursue strategic acquisitions of production properties and the development of coal seam projects subject to acceptable return hurdles.

Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved primarily through natural gas and oil swaps. During 2001, approximately 73 percent of the segment's overall production was hedged at fixed prices. Our hedging program is intended to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. Production's hedge positions are monitored and evaluated in an effort to achieve its earnings objectives and reduce the risks associated with spot-market price volatility.

In December 2001, El Paso announced the potential sale of natural gas and oil properties. See a discussion of the plan in Part II, Item 8, Financial Statements and Supplementary Data, Note 1.

Below are the operating results and analysis of these results for the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volumes and prices) | |
| Operating Results: | | |
| Natural gas | $ 1,562 | $ 956 |
| Oil, condensate and liquids | 200 | 162 |
| Other | 21 | 13 |
| Total operating revenues | 1,783 | 1,131 |
| Transportation and net product costs | (56) | (46) |
| Total operating margin | 1,727 | 1,085 |
| Operating expenses | (942) | (668) |
| Other income (loss) | 6 | (4) |
| EBIT | $ 791 | $ 413 |
| Volumes and Prices: | | |
| Natural gas | | |
| Volumes (MMcf) | 385,793 | 329,071 |
| Average realized prices ($/Mcf) | $ 3.99 | $ 2.83 |
| Oil, condensate and liquids | | |
| Volumes (MBbls) | 8,787 | 6,489 |
| Average realized prices ($/Bbl) | $ 22.16 | $ 24.86 |

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

Operating revenues for the year ended December 31, 2001, were $652 million higher than the same period in 2000. The increase was attributable to higher volumes and higher realized prices for natural gas and higher volumes for oil, condensate and liquids than in 2000.

Transportation and net product costs for the year ended December 31, 2001, were $10 million higher than the same period in 2000 primarily due to higher transported volumes and costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the year ended December 31, 2001, were $274 million higher than the same period in 2000. The increase was due to full cost ceiling test charges of $115 million on international properties incurred in the third quarter of 2001, higher depletion expense in 2001 as a result of increased production volumes combined with higher capitalized costs in the full cost pool and merger-related costs. Also contributing to the increase were higher severance and other production taxes in 2001, which are generally tied to natural gas and oil prices, and higher oilfield services costs.

Other income for the year ended December 31, 2001, was $10 million higher than the same period in 2000. The increase was primarily due to equity earnings from our investment in an El Paso affiliate. In June 2001, we contributed natural gas and oil properties to an affiliate in exchange for an equity investment and began recording equity earnings following the transfer. This transfer was accounted for at historical cost since the transfer was between entities under common control.

**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 ethane, propane and butane.

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 its operations earn margins from market-based rates. Revenues from these market-based rate services are the product of the 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 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 natural gas liquids prices are volatile.

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

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volumes and prices) | |
| Gathering, treating and processing gross margin | $ 155 | $ 188 |
| Operating expenses | (100) | (102) |
| Other income | 16 | 25 |
| EBIT | $ 71 | $ 111 |
| Volumes and prices | | |
| Gathering and treating | | |
| Volumes (BBtu/d) | 843 | 934 |
| Prices ($/MMBtu) | $ 0.15 | $ 0.14 |
| Processing | | |
| Volumes (inlet BBtu/d) | 1,966 | 1,864 |
| Prices ($/MMBtu) | $ 0.14 | $ 0.17 |

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

Total gross margin for the year ended December 31, 2001, was $33 million lower than the same period in 2000. The decrease was a result of lower natural gas liquids prices and volumes in 2001 and lower gathering and treating volumes in 2001 due to natural declines in production volumes in our operating regions.

Operating expenses for the year ended December 31, 2001, were $2 million lower than the same period in 2000. The decrease was due to lower operating and maintenance expenses due to cost savings following the merger. The decrease was partially offset by merger-related costs and other charges arising from the combined operations with El Paso, higher depreciation expense due to plant additions and capital expenditures and higher ad valorem and other taxes.

Other income for the year ended December 31, 2001, was $9 million lower than the same period in 2000. The decrease was primarily due to equity investment losses from our Mobile Bay and Aux Sable liquids processing facilities due to lower natural gas liquid prices, lower 2001 equity earnings from Deepwater Holdings as a result of the sale of our interest to El Paso Energy Partners L.P., our affiliate, in October 2001 and higher miscellaneous expenses in 2001. Partially offsetting the decrease was a gain on the sale of this investment.

**Corporate and Other Expenses, Net**

Corporate and other consists of miscellaneous general and administrative activities, as well as our retail operations, most of which were sold in 2001. Corporate expenses for the year ended December 31, 2001, were $776 million higher than the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with El Paso, costs associated with increased estimates of environmental remediation costs, legal obligations and usability of spare parts inventories, and lower retail margins due to the sale of substantially all of our retail gas stations in 2001.

**Non-Affiliated and Affiliated Interest and Debt Expense**

Total interest and debt expense for the year ended December 31, 2001, was $9 million lower than the same period in 2000 primarily due to retirement of non-affiliated short-term borrowings, consisting of approximately $1 billion of commercial paper and short-term bank credit facilities. This decrease was partially offset by increased affiliated interest when these debt instruments were replaced with advances from El Paso in the second quarter of 2001.

**Minority Interest**

Minority interest for the year ended December 31, 2001, was $9 million lower than the same period in 2000 primarily due to lower market interest rates. Our minority interest returns are primarily based on the London Interbank Offered Rate (LIBOR).

**Income Tax Expense**

Income tax expense for the year ended December 31, 2001, was $78 million. This amount includes $106 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges was 28 percent. For the year ended December 31, 2000 income tax expense was $252 million resulting in an effective tax rate of 28 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent in all years were primarily a result of the following factors:

- state income taxes;
- foreign income taxed at different rates;
- depreciation, depletion and amortization;

- non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities; and
- non-deductible dividends on the preferred stock of a subsidiary.

For a reconciliation of the statutory rate of 35 percent to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 6.

**New Accounting Pronouncements 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 $19 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.

In December 2001, El Paso announced a plan under which we may sell a variety of assets, including natural gas and oil properties and refining, chemical, coal mining and power assets. Should these sales occur, based on our current assessment of SFAS No. 144's provisions, our coal mining, chemical and refining assets are likely to qualify as discontinued operations under the standard. In addition, SFAS No. 144 establishes new rules when a company begins to take action to either dispose of, or otherwise alter the manner of operation of, an asset. Under these new rules, when it becomes "more likely than not" that a company will alter its current operating plans, an evaluation of possible impairment is made. Based on our actions to date, we are currently evaluating whether the assets we may sell are impaired under this standard. Based on preliminary indications of market value, coupled with the near-term outlook for the refining and coal mining industries, we anticipate that we may be required to write-down the carrying values of the refining and coal mining assets we may sell by an amount that could range from $145 million to $240 million after-tax under this standard. We continue to evaluate these and the other assets that may be sold as part of our plan.

*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.

**Other**

In August 2001, we completed the acquisition of Velvet Exploration Ltd., at a cost of approximately $230 million (approximately C$353 million) plus the assumption of $52 million (approximately C$80 million) in debt. Velvet is a Canadian exploration and development company, with a majority of its properties located in the Foothills and Deep Basin areas of western Alberta Province. The acquisition provides us with a strong platform to build a successful production business in western Canada by utilizing the expertise of Velvet's high quality workforce and its inventory of drilling prospects. The acquisition was accounted for as a purchase and resulted in an excess purchase price of $61 million (approximately C$97 million) that has been reflected as goodwill. We had other direct transaction costs and professional fees of $3 million (approximately C$4 million).

**Commitments and Contingencies**

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 13, and is incorporated herein by reference.

## 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 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 and interest rates. Our primary market risk exposures are to changing commodity prices. Our market risks are monitored by a corporate 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.

### Trading Commodity Price Risk

Prior to October 2000, we conducted our natural gas and power marketing and trading activities through Engage Energy U.S., L.P. and Engage Canada, L.P., a joint venture between us and Westcoast Energy Inc., a major Canadian natural gas company. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed Engage's U.S. trading activities. In February 2001, we transferred these activities to a subsidiary of El Paso. Our remaining trading price risk management activities were insignificant in 2001.

### Non-trading Commodity Price Risk

Our segments are exposed to a variety of market risks in the normal course of their business activities. Our Production segment has market risks related to the oil and natural gas it produces. Our Field Services segment has market risks related to the natural gas and natural gas liquids it retains in its processing operations. The refining activities in our Merchant Energy segment are exposed to market risks in both the feedstocks they use, primarily crude oil and petroleum based products as well as the refined products they sell. 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 payment 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.

The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments we use to mitigate these market risks that were outstanding at December 31, 2001 and 2000. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table.

| | | 10% Increase | | 10% Decrease | |
|---|---|---|---|---|---|
| | Fair Value | Fair Value | Increase (Decrease) | Fair Value | Increase (Decrease) |
| Impact of changes in commodity prices on derivative commodity instruments (in millions) | | | | | |
| December 31, 2001 | $ 501 | $ 312 | $(180) | $ 658 | $166 |
| December 31, 2000 | $(665) | $(785) | $(120) | $(545) | $120 |

In December 2001, we began measuring the risk associated with our commodity contracts held for non-trading purposes on a daily basis using the historical simulation technique of measuring Value-at-Risk to determine the maximum potential one-day unfavorable impact on our earnings, due to normal market movement and began monitoring our risk in comparison to established thresholds. This technique uses historical price movements and specific, defined mathematical parameters to estimate the characteristics of and the relationships between components of our assets and liabilities held for price risk management activities. Based on a confidence level of 95 percent and a one-day holding period, our estimated potential one-day unfavorable impact on earnings before interest and income taxes was $8 million at December 31, 2001.

### 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.

As of December 31, 2001, we maintained an interest rate swap transaction with a notional amount of $240 million exchanging LIBOR, a variable interest rate, for a fixed rate of 3.07%. This transaction results in the payment of a fixed rate of 4.49% until the swap terminates in June 2003. The fair value of this swap was immaterial as of December 31, 2001.

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 |
| | (In millions) | | | | | | | | | |
| **Liabilities:** | | | | | | | | | | |
| Short-term debt — variable rate | $ 33 | | | | | | $ 33 | $ 33 | $ 798 | $ 798 |
| Average interest rate | 2.4% | | | | | | | | | |
| Long-term debt, including current portion — fixed rate | $ 252 | $102 | $694 | $182 | $501 | $2,634 | $4,365 | $4,352 | $4,400 | $4,501 |
| Average interest rate | 8.1% | 9.7% | 6.9% | 10.1% | 7.2% | 7.7% | | | | |
| Long-term debt, including current portion — variable rate | $1,058 | $275 | $296 | $128 | $262 | $ 33 | $2,052 | $2,052 | $1,893 | $1,912 |
| Average interest rate | 2.7% | 5.1% | 6.1% | 6.0% | 6.2% | 5.6% | | | | |
| Notes payable to unconsolidated affiliates — variable rate | $ 67 | | | | | | $ 67 | $ 67 | $ — | $ — |
| Average interest rate | 4.9% | | | | | | | | | |
| **Company-obligated preferred securities:** | | | | | | | | | | |
| Coastal Finance I | | | | | | $ 300 | $ 300 | $ 299 | $ 300 | $ 293 |
| Average fixed interest rate | | | | | | 8.4% | | | | |

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### EL PASO CGP COMPANY

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| Operating revenues | $25,706 | $26,936 | $16,596 |
| Operating expenses | | | |
| Cost of natural gas and other products | 21,920 | 23,552 | 14,037 |
| Operation and maintenance | 1,663 | 1,500 | 1,224 |
| Merger-related costs and asset impairments | 986 | 34 | — |
| Ceiling test charges | 115 | — | — |
| Depreciation, depletion and amortization | 729 | 657 | 493 |
| Taxes, other than income taxes | 181 | 140 | 99 |
| | 25,594 | 25,883 | 15,853 |
| Operating income | 112 | 1,053 | 743 |
| Other income | | | |
| Earnings from unconsolidated affiliates | 223 | 265 | 190 |
| Other, net | 110 | 150 | 95 |
| | 333 | 415 | 285 |
| Income before interest, income taxes and other charges | 445 | 1,468 | 1,028 |
| Non-affiliated interest and debt expense | 447 | 502 | 323 |
| Affiliated interest expense, net | 46 | — | — |
| Minority interest | 51 | 60 | 32 |
| Income taxes | 78 | 252 | 174 |
| | 622 | 814 | 529 |
| Income (loss) before extraordinary items | (177) | 654 | 499 |
| Extraordinary items, net of income taxes | (11) | — | — |
| Net income (loss) | $ (188) | $ 654 | $ 499 |

See accompanying notes.

## EL PASO CGP COMPANY

## CONSOLIDATED BALANCE SHEETS
**(In millions)**

| | December 31, 2001 | December 31, 2000 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 131 | $ 53 |
| Accounts and notes receivable, net of allowance of $36 in 2001 and $19 in 2000 | | |
| Customer | 1,821 | 2,549 |
| Affiliates | 546 | 88 |
| Other | 211 | 388 |
| Inventory | 693 | 1,167 |
| Assets from price risk management activities | 425 | 580 |
| Other | 357 | 223 |
| Total current assets | 4,184 | 5,048 |
| Property, plant and equipment, at cost | | |
| Pipelines | 6,558 | 6,092 |
| Refining, crude oil and chemical facilities | 2,425 | 2,338 |
| Power facilities | 271 | 237 |
| Natural gas and oil properties, at full cost | 7,765 | 5,100 |
| Gathering and processing systems | 428 | 340 |
| Other | 516 | 744 |
| | 17,963 | 14,851 |
| Less accumulated depreciation, depletion and amortization | 5,945 | 4,248 |
| Total property, plant and equipment, net | 12,018 | 10,603 |
| Other assets | | |
| Investments in unconsolidated affiliates | 1,883 | 1,613 |
| Assets from price risk management activities | 267 | 138 |
| Other | 714 | 1,473 |
| | 2,864 | 3,224 |
| Total assets | $19,066 | $18,875 |

See accompanying notes.

## EL PASO CGP COMPANY

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

| | December 31, 2001 | December 31, 2000 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDER'S EQUITY** | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $ 1,858 | $ 1,804 |
| Affiliates | 1,360 | 13 |
| Other | 360 | 1,403 |
| Short-term borrowings and other financing obligations | 1,410 | 1,094 |
| Liabilities from price risk management activities | 213 | 546 |
| Other | 600 | 348 |
| Total current liabilities | 5,801 | 5,208 |
| Debt | | |
| Long-term debt and other financing obligations | 5,107 | 5,997 |
| Other | | |
| Liabilities from price risk management activities | 1 | 113 |
| Deferred income taxes | 1,740 | 1,956 |
| Other | 553 | 300 |
| | 2,294 | 2,369 |
| Commitments and contingencies | | |
| Securities of subsidiaries | | |
| Company-obligated preferred securities of consolidated trusts | 300 | 300 |
| Minority interests | 594 | 451 |
| | 894 | 751 |
| Stockholder's equity | | |
| Cumulative preferred stock, no shares outstanding in 2001; with aggregate liquidation preference of $7.3 million at December 31, 2000 | — | — |
| Class A common stock, no shares outstanding in 2001; par value 33 1/3¢, 311,377 shares issued in 2000 | — | — |
| Common stock, par value $1 per share; 1,000 shares authorized and issued in 2001; par value 33 1/3¢ per share, 219,604,836 shares issued in 2000 | — | 73 |
| Additional paid-in capital | 1,305 | 1,044 |
| Retained earnings | 3,385 | 3,573 |
| Accumulated other comprehensive income | 280 | (8) |
| Treasury stock (at cost); no shares in 2001 and 4,394,651 shares in 2000 | — | (132) |
| Total stockholder's equity | 4,970 | 4,550 |
| Total liabilities and stockholder's equity | $19,066 | $18,875 |

See accompanying notes.

## EL PASO CGP COMPANY

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| Cash flows from operating activities | | | |
| Net income (loss) | $ (188) | $ 654 | $ 499 |
| Adjustments to reconcile net income (loss) to net cash from operating activities | | | |
| Depreciation, depletion and amortization | 729 | 657 | 493 |
| Ceiling test charges | 115 | — | — |
| Deferred income tax expense (benefit) | (38) | 203 | 112 |
| Extraordinary items | 6 | — | — |
| Undistributed earnings of unconsolidated affiliates | (96) | (3) | (39) |
| Non-cash portion of merger-related costs, asset impairments and changes in estimates | 1,180 | — | — |
| Net gain on the sale of assets | (6) | (18) | — |
| Working capital changes, net of non-cash transactions | | | |
| Accounts and notes receivable | (296) | (485) | (809) |
| Accounts payable/receivable with affiliates | (131) | — | — |
| Inventory | 422 | (137) | (269) |
| Change in price risk management activities, net | 67 | (29) | — |
| Accounts payable | 382 | 188 | 578 |
| Other working capital changes | (376) | 75 | 192 |
| Non-working capital changes and other | 182 | 34 | 9 |
| Net cash provided by operating activities | 1,952 | 1,139 | 766 |
| Cash flows from investing activities | | | |
| Additions to property, plant and equipment | (2,301) | (2,112) | (1,781) |
| Additions to investments | (386) | (286) | (379) |
| Cash paid for acquisitions, net of cash acquired | (232) | — | — |
| Net proceeds from the sale of assets | 268 | 59 | 37 |
| Proceeds from the sale of investments | 363 | 59 | 10 |
| Repayment of notes receivable from unconsolidated affiliates | 273 | — | — |
| Other | 1 | (1) | (3) |
| Net cash used in investing activities | (2,014) | (2,281) | (2,116) |
| Cash flows from financing activities | | | |
| Net borrowings (repayments) of commercial paper and short-term credit facilities | (765) | 217 | 94 |
| Payments to retire long-term debt and other financing obligations | (608) | (738) | (487) |
| Net proceeds from the issuance of long-term debt and other financing obligations | 490 | 1,722 | 1,345 |
| Issuances of common stock | 2 | 31 | 15 |
| Dividends paid | (13) | (54) | (54) |
| Net proceeds from issuance of minority interests in subsidiaries | 139 | — | 350 |
| Net change in other affiliated advances payable | 889 | — | — |
| Other | 6 | — | — |
| Net cash provided by financing activities | 140 | 1,178 | 1,263 |
| Increase (decrease) in cash and cash equivalents | 78 | 36 | (87) |
| Cash and cash equivalents | | | |
| Beginning of period | 53 | 17 | 104 |
| End of period | $ 131 | $ 53 | $ 17 |

See accompanying notes.

# EL PASO CGP COMPANY

## CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
## (In thousands of shares and millions of dollars, except per share amounts)

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2001 | | 2000 | | 1999 | |
| | Shares | Amount | Shares | Amount | Shares | Amount |
| Preferred stock, par value 33⅓¢ per share, authorized 50,000 shares cumulative convertible preferred | | | | | | |
| $1.19, Series A: Beginning balance | 52 | $ — | 53 | $ — | 56 | $ — |
| Converted to common stock | — | — | (1) | — | (3) | — |
| Converted to El Paso common stock | (52) | | | | | |
| Ending balance | — | — | 52 | — | 53 | — |
| $1.83, Series B: Beginning balance | 51 | — | 58 | — | 61 | — |
| Converted to common stock | — | — | (7) | — | (3) | — |
| Converted to El Paso common stock | (51) | | | | | |
| Ending balance | — | — | 51 | — | 58 | — |
| $5.00, Series C: Beginning balance | 26 | — | 27 | — | 28 | — |
| Converted to common stock | — | — | (1) | — | (1) | — |
| Converted to El Paso common stock | (26) | | | | | |
| Ending balance | — | — | 26 | — | 27 | — |
| Class A common stock, par value 33⅓¢ per share, authorized 2,700 shares | | | | | | |
| Beginning balance | 311 | — | 345 | — | 354 | — |
| Converted to common stock | — | — | (35) | — | (12) | — |
| Conversion of preferred stock and exercise of stock options | — | — | 1 | — | 3 | — |
| Converted to El Paso common stock | (311) | | | | | |
| Ending balance | — | — | 311 | — | 345 | — |
| Common stock, par value 33⅓¢ per share, authorized 500,000 shares | | | | | | |
| Beginning balance | 219,605 | 73 | 217,705 | 72 | 216,765 | 72 |
| Exercise of stock options | 86 | — | 1,793 | 1 | 863 | — |
| Conversion to El Paso common stock | (219,690) | (73) | — | | — | |
| Other | — | — | 107 | — | 77 | — |
| Ending balance | 1 | — | 219,605 | 73 | 217,705 | 72 |
| Additional paid-in capital | | | | | | |
| Beginning balance | | 1,044 | | 1,032 | | 1,016 |
| Merger-related equity exchange | | (59) | | — | | — |
| Capital contribution from El Paso | | 278 | | — | | — |
| Tax reallocation | | 36 | | — | | — |
| Other | | 6 | | 12 | | 16 |
| Ending balance | | 1,305 | | 1,044 | | 1,032 |
| Retained earnings | | | | | | |
| Beginning balance | | 3,573 | | 2,973 | | 2,528 |
| Net income (loss) for period | | (188) | | 654 | | 499 |
| Dividends on common stock, 25¢ per share in 2000 and 1999 | | — | | (54) | | (54) |
| Ending balance | | 3,385 | | 3,573 | | 2,973 |
| Accumulated other comprehensive income | | | | | | |
| Beginning balance | | (8) | | (8) | | (8) |
| Other comprehensive income | | 288 | | — | | — |
| Ending balance | | 280 | | (8) | | (8) |
| Treasury stock, at cost | | | | | | |
| Beginning balance | (4,395) | (132) | (4,396) | (132) | (4,396) | (132) |
| Retirement of treasury shares | 4,395 | 132 | — | — | — | — |
| Other | — | — | 1 | — | — | — |
| Ending balance | — | — | (4,395) | (132) | (4,396) | (132) |
| Total | | $4,970 | | $4,550 | | $3,937 |

See accompanying notes.

# EL PASO CGP COMPANY

## 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 (loss) | $(188) | $654 | $499 |
| Foreign currency translation adjustments | (30) | — | — |
| Unrealized net gains (losses) from cash flow hedging activities | | | |
| Cumulative-effect transition adjustment (net of tax of $248) | (459) | — | — |
| Reclassification of initial cumulative-effect of transition adjustment at original value (net of tax of $246) | 456 | — | — |
| Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $220) | (406) | — | — |
| Unrealized mark-to-market gains arising during period (net of tax of $398) | 727 | — | — |
| Other comprehensive income | 288 | — | — |
| Comprehensive income | $ 100 | $654 | $499 |
| **Accumulated Other Comprehensive Income** | | | |
| Beginning balances as of January 1, | $ (8) | $ (8) | $ (8) |
| Foreign currency translation adjustments | (30) | — | — |
| Unrealized net gains (losses) from cash flow hedging activities | | | |
| Cumulative-effect of transition adjustment, net of taxes | (459) | — | — |
| Reclassification of initial cumulative-effect transition adjustment at original value, net of taxes | 456 | — | — |
| Additional reclassification adjustments for changes in initial value to settlement date, net of taxes | (406) | — | — |
| Unrealized mark-to-market gains arising during period, net of taxes | 727 | — | — |
| Balance as of December 31, | $ 280 | $ (8) | $ (8) |

See accompanying notes.

# EL PASO CGP COMPANY

# 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 stockholder's 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.

*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 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 refined products, crude oil and chemicals, materials and supplies, natural gas in storage for non-trading purposes and coal. We use the first-in, first-out method to account for our refined products, crude oil and chemicals inventories and the average cost method to account for our other inventories. We value all inventory at the lower of its cost or market value.

*Natural Gas and Oil Imbalances*

Natural gas and oil imbalances occur when the actual amount of natural gas or oil 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 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 unconsolidated affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to unconsolidated 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 the fair value of the assets acquired. We capitalize direct costs, such as labor and materials, and indirect costs, such as overhead and interest. We capitalize the major units of property replacements or improvements and expense minor items.

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) | |
| Pipeline and storage systems | Straight-line | 2-61 | 2% to 27% |
| Refining, crude oil and chemical facilities | Straight-line | 1-33 | 3% to 20% |
| Power facilities | Straight-line | 2-14 | 5% to 33% |
| Gathering and processing systems | Straight-line | 1-40 | 3% to 25% |
| Coal facilities | Straight-line | 1-30 | 3% to 33% |
| Transportation equipment | Straight-line | 1-5 | 10% to 33% |
| Buildings and improvements | Straight-line | 1-43 | 2% to 14% |
| Office and miscellaneous equipment | Straight-line | 1-10 | 5% to 33% |

When we retire facilities, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage. Any remaining gain or loss is recorded in income.

*Asset Impairments*

We evaluate our long-lived assets for impairment 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, operating costs, legal, regulatory and other factors, and these assumptions can change either positively or negatively.

*Natural Gas and Oil Properties*

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties, internal costs directly related to acquisition and exploration activities and capitalized interest.

We amortize these costs using the unit of production method over the life of our proved reserves. Our total capitalized costs are limited to a ceiling based on the present value of future net revenues using current prices, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. If these discounted revenues are not equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as ceiling test charges. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated future natural gas and oil production.

We do not recognize a gain or loss on sales of our natural gas and oil properties, unless the properties sold are significant. We treat sales as an adjustment to the cost of our properties.

*Planned Major Maintenance*

Repair and maintenance costs are generally expensed as incurred, unless they improve the operating efficiency or extend the useful life of an asset.

In our domestic refining business, repair and maintenance costs for planned major maintenance activities are accrued as a liability in a systematic and rational manner over the period of time until the planned major maintenance activities occur. Any difference between the accrued liability and the actual costs incurred in performing the maintenance activities are charged or credited to expense at the time the maintenance occurs. At our international refineries, the cost of each major maintenance activity is capitalized and amortized to expense in a systematic and rational manner over the estimated period extending to the next planned major maintenance activity. The types of costs we accrue in conjunction with major maintenance at our refineries are outside contractor costs, materials and supplies, company labor and other outside services. For our domestic operations, we had accruals for major maintenance of $36 million and $51 million at December 31, 2001 and 2000, and for our international operations, we capitalized $56 million and $53 million at December 31, 2001 and 2000.

*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 charge in our income statement.

*Revenue Recognition*

Our 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 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 for 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 that involve cash settlements or physical delivery of a commodity;
- swap contracts that 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 EITF Issue 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. 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 natural gas and oil production, refining, natural gas transmission and power generation 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 other 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 tax directly to the IRS and bills or refunds its subsidiaries for their portion of these income tax payments. Prior to 2001, we filed a separate tax return and were not subject to El Paso's tax sharing policy.

*Excise Taxes*

In our retail activities, we account for excise taxes by recording amounts billed to customers in operating revenues with a corresponding entry for amounts owed in operating expenses. In our refining and marketing operations, we do not record the amounts of excise taxes we bill and collect from customers in revenues. Rather, we record a receivable from our customers and a payable to the government agencies or suppliers. As of December 31, 2001, 2000 and 1999, we had recorded approximately $69 million, $198 million and $231 million in excise taxes related to our retail activities. Additionally in 2001, we recorded $323 million of excise taxes on our balance sheet relating to our refining and marketing operations.

*Foreign Currency Transactions and Translation*

We record all currency transaction gains and losses in income. The net currency loss recorded to income was insignificant in 2001 and 2000. The U.S. dollar is the functional currency for substantially all of our foreign operations. For those operations, all gains and losses from currency translations are included in income currently. 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 $38 million and $8 million at December 31, 2001 and 2000. Revenues and expenses are translated at average exchange rates prevailing during the year.

*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. Merger with El Paso Corporation

In January 2001, we merged with El Paso. In the merger, holders of our common stock and Class A common stock received 1.23 shares of El Paso common stock for each outstanding common share; holders of our Series A and Series B convertible preferred stock received 9.133 shares of El Paso common stock for each outstanding convertible preferred share; and holders of our Series C convertible preferred stock received 17.98 shares of El Paso common stock for each outstanding convertible preferred share. All these exchanges were done on a tax free basis. In addition, holders of our outstanding stock options received shares of El Paso common stock based on the fair value of these options on the date of the merger. As a result of the merger, El Paso owns 100 percent of our common equity.

Under a FTC order, as a result of our merger with El Paso, we sold our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems and our investments in the Empire State and Iroquois pipeline systems. For the year ended December 31, 2001, net proceeds from these sales were approximately $184 million, and we recognized an extraordinary net loss of approximately $11 million, net of income taxes of approximately $5 million.

## 3. Merger-Related Costs and Asset Impairments

The following table reflects costs related to our merger with El Paso and asset impairments for the years ended December 31, 2001 and 2000. We incurred no merger or asset impairment charges in 1999.

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Merger-related costs | $977 | $13 |
| Asset impairments | 9 | 21 |
| | $986 | $34 |

*Merger-Related Costs.* Our merger-related costs relate to our merger with El Paso and consisted of the following for the years ended December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Employee severance, retention and transition costs | $586 | $— |
| Transaction costs | 7 | 13 |
| Business and operational integration costs | 122 | — |
| Merger-related asset impairments | 162 | — |
| Other | 100 | — |
| | $977 | $13 |

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 our merger-related workforce reduction and consolidation. Following the merger, El Paso completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,200 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of these restructurings. Retention charges include payments to employees who were retained following the mergers and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The pension and post-retirement benefits were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid.

Also included in the 2001 employee severance, retention and transition costs, was a charge of $278 million resulting from the issuance of approximately 4 million shares of El Paso common stock on the merger date in exchange for the fair value of our employees' and directors' stock options.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete the merger. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under the El Paso combined operating strategy and incremental fees under software and seismic license agreements. Also included in the 2001 charges are approximately $121 million in estimated lease related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas. These charges were accrued at the time we completed our relocations and closed this office. The amounts accrued will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed as incurred.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following the merger. These charges occurred in our Merchant Energy, Production and Pipelines segments, and all of these assets have either had their operations suspended or continue to be held for use. The charges taken were based on a comparison of the cost of the assets to their estimated fair value to the ongoing operations based on this change in operating strategy.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with El Paso and other miscellaneous charges. These items were expensed in the period in which they were incurred.

*Asset Impairments.* The 2001 asset impairment charges resulted from the inability to recover capitalized costs of Merchant Energy's Corpus Christi refinery and related assets as a result of the lease of these assets to Valero in June 2001. The 2000 charges consisted of the impairment of coal mining and refining assets. These impairments 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 operation has been suspended.

**4. Changes in Accounting Estimates**

Included in our operation and maintenance costs for the year ended December 31, 2001, were approximately $317 million in costs related to changes in accounting estimates which consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $38 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. These changes were primarily the result of several events that occurred as part of and following our merger with El Paso, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These changes were also a direct result of a fire at our Aruba refinery. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. These charges are included as operating expenses in our income statement and reduced our net income before extraordinary items and net income for the year ended December 31, 2001, by approximately $241 million.

**5. Ceiling Test Charges**

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. During the third quarter of 2001, capitalized costs exceeded this ceiling limit by $115 million, including $87 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool. These charges were based on the November 1, 2001 daily posted oil and natural gas sales prices, adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. This non-cash write-down is included in our income statement as ceiling test charges.

We use financial instruments to hedge against volatility of natural gas and oil prices. The impact of these hedges was considered in the determination of our ceiling test charge during 2001 and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our 2001 ceiling test charge, the charge would not have materially changed since we do not significantly hedge our international production activities.

Also as mentioned above, our 2001 charge was computed based on daily posted prices on November 1, 2001. Had we computed this charge based on the daily oil and natural gas prices as of September 30, 2001, the charge would have been approximately $255 million, including approximately $227 million for our Canadian full cost pool and $28 million for our Brazilian full cost pool, including the impact on future cash flows of our hedging program. Had the impact of our hedging program been excluded, the charges would have been approximately the same for our international full cost pools and production operations, but we would have incurred an additional charge of approximately $830 million related to our U.S. full cost pool.

**6. Income Taxes**

Pretax income (loss) before extraordinary items is composed of the following for the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | (In millions) | | |
| United States | $(137) | $721 | $554 |
| Foreign | 38 | 185 | 119 |
| | $ (99) | $906 | $673 |

The following table reflects the components of income tax expense included in income (loss) before extraordinary items for the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Current | | | |
| Federal | $ 94 | $ 41 | $ 45 |
| State | (5) | (1) | 9 |
| Foreign | 6 | 9 | 8 |
| | 95 | 49 | 62 |
| Deferred | | | |
| Federal | 35 | 189 | 112 |
| State | (15) | 11 | (3) |
| Foreign | (37) | 3 | 3 |
| | (17) | 203 | 112 |
| Total income tax expense | $ 78 | $252 | $174 |

Our tax expense, included in income (loss) before extraordinary items, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Tax expense at the statutory federal rate of 35% | $(35) | $317 | $236 |
| Increase (decrease) | | | |
| Tight sands gas credit | — | (6) | (6) |
| State income taxes | (13) | 6 | 4 |
| Foreign income taxed at different tax rates | (2) | (48) | (52) |
| Depreciation, depletion and amortization | 20 | (17) | (10) |
| Non-deductible portion of merger costs and other tax adjustments to provide for revised estimated liabilities | 106 | — | — |
| Non-deductible dividends on preferred stock of subsidiaries | 3 | 4 | — |
| Other | (1) | (4) | 2 |
| Income tax expense | $ 78 | $252 | $174 |
| Effective tax rate | (79)% | 28% | 26% |

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

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Deferred tax liabilities | | |
| Property, plant and equipment | $1,771 | $1,780 |
| Pensions and benefit costs | — | 160 |
| Investments in unconsolidated affiliates | 255 | 191 |
| Price risk management activities | 173 | — |
| Other assets | 507 | 114 |
| Total deferred tax liability | 2,706 | 2,245 |
| Deferred tax assets | | |
| U.S. net operating loss and tax credit carryovers | 256 | 212 |
| Environmental liability | 99 | — |
| Employee benefit and deferred compensation obligations | 12 | — |
| Other liabilities | 564 | 169 |
| Total deferred tax asset | 931 | 381 |
| Net deferred tax liability | $1,775 | $1,864 |

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 $754 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 adjustment recorded in other comprehensive income.

The tax benefit associated with the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends, reduced taxes payable by $5 million in 2001 (allocated to us under El Paso's tax sharing policy), $18 million in 2000 and $6 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 $153 million that carryover indefinitely and $293 million of net operating loss carryovers for which the carryover period ends in 2021. 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 IRS regulations.

## 7. 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: | | | | |
| Long-term debt and other obligations, including current maturities | $ 6,417 | $ 6,404 | $ 6,293 | $ 6,413 |
| Notes payable to unconsolidated affiliates | 67 | 67 | — | — |
| Company obligated preferred securities of subsidiaries | 300 | 299 | 300 | 293 |
| Trading instruments | | | | |
| Futures contracts | (34) | (34) | 15 | 15 |
| Option contracts | (4) | (4) | 12 | 12 |
| Swap and forward contracts[1] | (4) | (4) | 226 | 226 |
| Other financial instruments: | | | | |
| Non-Trading instruments[2] | | | | |
| Commodity swap and forward contracts | $ 491 | $ 491 | $ — | $ (692) |
| Commodity futures contracts | 10 | 10 | — | — |

(1) Excludes all physical contracts.

(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.

*Commodity Trading Activities*

Prior to October 2000, we conducted our natural gas and power marketing and trading activities through Engage Energy U.S., L.P. and Engage Canada, L.P., a joint venture between us and Westcoast Energy Inc., a major Canadian natural gas company. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed Engage's U.S. trading activities. In February 2001, we transferred these activities to a subsidiary of El Paso. See Note 17 for a further discussion of this transfer.

We recognized gross margins from our trading activities of $15 million and $33 million for the years 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. The information below includes information for the trading operations we assumed from Engage for the periods it was consolidated in our operations.

| | Assets | Liabilities | Average Fair Value for the Year Ended December 31,[1] |
|---|---|---|---|
| | | (In millions) | |
| **2001** | | | |
| Futures contracts | $ 150 | $ (184) | $ (13) |
| Option contracts | 10 | (14) | (15) |
| Swap and forward contracts | 25 | (10) | — |
| **2000** | | | |
| Futures contracts | $ 15 | $ — | $ (3) |
| Option contracts | 59 | (47) | 9 |
| Swap and forward contracts | 644 | (612) | 170 |

(1) Computed using the net asset (liability) balance at 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: | | | |
| Crude oil (MMBbls) | 104 | 57 | 3 |
| **2000** | | | |
| Energy Commodities: | | | |
| Natural gas (Bcf) | 767 | 677 | 9 |
| Crude oil (MMBbls) | 42 | 39 | 2 |

The notional amounts included in the table above reflect the contracted notional volume 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 weighted average maturity of our entire portfolio of price risk management activities was approximately three 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 our 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) | Total |
| | (In millions) | | |
| Energy marketers | $ 18 | $ — | $ 18 |
| Financial institutions | 167 | — | 167 |
| Total assets from trading price risk management activities | $185 | $ — | $185 |

| | Assets from Trading Price Risk Management Activities as of December 31, 2000 | | |
|---|---|---|---|
| | Investment Grade(1) | Below Investment Grade(1) | Total |
| | (In millions) | | |
| Energy marketers | $151 | $26 | $177 |
| Financial institutions | 372 | — | 372 |
| Natural gas and oil producers | 29 | 1 | 30 |
| Natural gas and electric utilities | 62 | 14 | 76 |
| Industrials | 5 | — | 5 |
| Natural gas and electric utilities not publicly traded | 58 | — | 58 |
| Total assets from trading price risk management activities | $677 | $41 | $718 |

(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 credit ratings that do not meet the criteria of "Investment Grade".

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 Term in Years | Notional Volume | | Maximum Term in Years |
| | Buy | Sell | | Buy | Sell | |
| Commodity | | | | | | |
| Natural Gas (TBtu) | 12 | 12 | 6 | 1 | 157 | 2 |
| Crude oil and refined products (MMBbls) | 117 | 113 | 1 | 115 | 135 | 1 |

As of December 31, 2001, we had an interest rate swap transaction with a notional amount of $240 million exchanging LIBOR, a variable interest rate, for a fixed rate of 3.07%. This swap was entered into as a hedge of the variable interest rates on a loan with a principal amount of $240 million that matures in March 2004. The swap converts the variable interest payments on the loan to a fixed rate of 4.49% until the swap terminates in June 2003. The fair value of this swap was immaterial as of December 31, 2001.

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.

## 8. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $459 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, $456 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 discussion of our hedging activities is as follows:

*Fair Value Hedges.* We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the year ended December 31, 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

*Cash Flow Hedges.* 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 flows hedges included in accumulated other comprehensive income was an unrealized gain of $318 million, net of income taxes. We estimate that unrealized gains of $165 million, net of income taxes, will be reclassified from accumulated other comprehensive income over the next 12 months. Reclassifications occur upon physical delivery of the hedge commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 2 years; however, most of our cash flow hedges expire within the next 12 months.

Our accumulated other comprehensive income also includes our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges, which was less than $1 million at December 31, 2001.

For the year ended December 31, 2001, we recognized net losses of $1 million, net of income taxes, related to the ineffective portion of all cash flow hedges.

## 9. Inventory

Our inventory consisted of the following at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Refined products, crude oil and chemicals | $576 | $1,004 |
| Coal, materials and supplies and other | 117 | 163 |
| Total | $693 | $1,167 |

## 10. Property, Plant and Equipment

At December 31, 2001 and 2000, we had approximately $1,030 million and $1,481 million construction work in progress included in our property, plant and equipment.

In June 2001, we entered into a 20-year lease agreement related to our Corpus Christi refinery and related assets with Valero Energy Corporation. Under the lease, Valero pays us a quarterly amount that increases after the second year of the lease. For the year ended December 31, 2001, we recorded $11 million in lease income related to this lease. In addition, Valero has the option to purchase the plant and related assets in 2003 for approximately $294 million, and a similar option each year thereafter at an annually increasing amount. The net book value of the plant and related assets was approximately $225 million at December 31, 2001. Based on the terms, the lease qualified as an operating lease with total minimum lease payments of $811 million with future minimum lease payments totaling $797 million; $19 million in 2002; $37 million in 2003; $43 million in each of 2004, 2005 and 2006; and a total of $612 million thereafter.

## 11. Debt, Other Financing Obligations and Other Credit Facilities

At December 31, 2001, our weighted average interest rate on our commercial paper and short-term credit facilities was 2.4%, and at December 31, 2000, it was 7.15%. We had the following short-term borrowings and other financing obligations at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Commercial paper | $ — | $ 455 |
| Short-term credit facilities | 30 | 340 |
| Notes payable to unconsolidated affiliates | 67 | — |
| Current maturities of long-term debt and other financing obligations | 1,310 | 296 |
| Other | 3 | 3 |
| | $1,410 | $1,094 |

*Credit Facilities*

In January 2001, we terminated approximately $1.5 billion in revolving credit facilities and became a designated borrower under El Paso's 364-day and 3-year revolving credit and competitive advance facilities. In June 2001, El Paso replaced its existing 364-day revolving credit facility, and we are not a designated borrower under the new facility. The interest rate on the 3-year revolving credit and competitive advance facility varies and was based on the LIBOR plus 50 basis points at December 31, 2001. No amounts were outstanding under this facility as of December 31, 2001.

Our long-term debt and other financing obligations outstanding consisted of the following at December 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Long-term debt | | |
| El Paso CGP | | |
| Notes payable (revolving credit agreement) | $ — | $ 135 |
| Senior notes, 6.2% through 10.375%, due 2001 through 2010 | 1,565 | 1,650 |
| Floating rate senior notes, due 2002 and 2003(1) | 600 | 600 |
| Senior debentures, 6.375% through 10.75%, due 2003 through 2037 | 1,497 | 1,497 |
| FELINE PRIDES, 6.625% due 2004 | 460 | 460 |
| Valero lease financing loan due 2004 | 240 | — |
| El Paso Production Company | | |
| Floating rate notes, due 2005 and 2006 | 200 | 100 |
| ANR Pipeline | | |
| Debentures, 7.0% through 9.625%, due 2021 through 2025 | 500 | 500 |
| Colorado Interstate Gas | | |
| Debentures, 6.85% and 10.0%, due 2005 and 2037 | 280 | 280 |
| Other | 369 | 233 |
| | 5,711 | 5,455 |
| Less: | | |
| Unamortized discount | 9 | 12 |
| Current maturities | 720 | 147 |
| Long-term debt, less current maturities | 4,982 | 5,296 |
| Other Financing Obligations | | |
| Crude oil prepayments | 500 | 500 |
| Natural gas production payment | 215 | 350 |
| | 715 | 850 |
| Less: | | |
| Current maturities | 590 | 149 |
| Other financing obligations, less current maturities | 125 | 701 |
| Total long-term debt and other financing obligations, less current maturities | $5,107 | $5,997 |

(1) In March 2002, we retired $400 million of these notes.

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in millions):

| | |
|---|---|
| 2002 | $1,310 |
| 2003 | 380 |
| 2004 | 996 |
| 2005 | 310 |
| 2006 | 763 |
| Thereafter | 2,667 |
| Total long-term debt and other financing obligations including current maturities | $6,426 |

In October 2001, we borrowed $240 million due in 2004 under a loan agreement. The loan is collateralized by the lease payments from Valero under their lease of our Corpus Christi refinery.

In 1999, we issued a total of 18,400,000 FELINE PRIDES[SM] consisting of 17,000,000 Income PRIDES with a stated value of $25 and 1,400,000 Growth PRIDES with a stated value of $25. The Income PRIDES consist of a unit comprised of a Senior Debenture and a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock. The Growth PRIDES consist of a unit comprised of a purchase contract under which the holder is obligated to purchase from us by no later than August 16, 2002 for $25 (the stated price) a number of shares of our common stock and a 2.5% undivided beneficial interest in a three-year Treasury security having a principal amount at maturity equal to $1,000. Under the terms of the purchase contract in effect prior to the merger with El Paso, the number of shares of common stock the holder of a PRIDE received varied between 0.5384 and 0.6568 shares, depending on the price of our common stock.

As a result of the merger with El Paso, and under the terms of the purchase contract, the number of shares the holder of a PRIDE is entitled and required to receive upon settlement became fixed at 0.6622 shares of El Paso common stock. This will result in the issuance of approximately 12.2 million shares of El Paso common stock.

Our other financing obligations consist of crude oil prepayments received from third parties in exchange for our agreement to deliver a fixed quantity of crude oil to a specified delivery point in the future and a production payment received in exchange for delivery of a fixed quantity of natural gas from our future production. These agreements, by their terms, can only be settled through the delivery of the commodity. We have entered into commodity swaps to effectively lock-in the value of these commitments to the third party upon delivery of the commodity. We will continue to deliver natural gas under the production payment agreement according to its terms, but consider these agreements to be financing arrangements. The carrying cost of the prepayments and the production payment are recognized as interest expense in our income statement.

*Other Financing Arrangements*

During 2000, El Paso formed a series of companies to provide financing to invest in various El Paso capital projects and other assets. The proceeds are collateralized by various fixed assets, including our Colorado Interstate Gas transmission system.

*Other Financial Activities*

Our significant long-term debt borrowing and repayment activities during 2001 were as follows:

| Date | Company | Type | Interest Rate | Principal | Net Proceeds[1] | Due Date |
|---|---|---|---|---|---|---|
| | | | | (In millions) | | |
| *Issuances* | | | | | | |
| **2001** | | | | | | |
| January | El Paso CGP | Crude oil prepayment | Variable | $ 150 | $150 | 2002 |
| October | El Paso CGP | Loan[2] | 4.49% | 240 | 240 | 2004 |
| Jan.-Dec. | El Paso Production | Various | Various | 100 | 100 | 2005-2006 |
| *Retirements* | | | | | | |
| **2001** | | | | | | |
| January | El Paso Production | Crude oil prepayment | Variable | $ 150 | | 2001 |
| February | El Paso CGP | Long-term debt | Variable | 135 | | 2001 |
| February | El Paso CGP | Long-term debt | 10.00% | 85 | | 2001 |
| Jan.-Dec. | El Paso Production | Natural gas production payment | LIBOR+0.372% | 135 | | 2001 |
| Jan.-Dec. | El Paso CGP | Various | Various | 103 | | 2001 |

(1) Net proceeds were primarily used to repay short-term borrowings and for general corporate purposes.

(2) The loan is collateralized by the lease payments from Valero for our Corpus Christi refinery and related assets. The interest rate on the loan is LIBOR plus 1.425%. To reduce our exposure to interest rate risk, we entered into a swap transaction with a notional amount of $240 million exchanging LIBOR for a fixed rate of 3.07%. This transaction results in the payment of a fixed rate of 4.495% until the swap terminates in June 2003.

## 12. Securities of Subsidiaries and Minority Interests

*Company-obligated Preferred Securities of a Consolidated Trust.*

*Coastal Finance I.* In May 1998, we completed a public offering of 12 million mandatory redemption preferred securities on Coastal Finance I, a business trust, for $300 million. Coastal Finance I holds debt securities of ours purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375% of the liquidation amount of $25 per preferred security. The preferred securities are mandatorily redeemable on the maturity date, May 13, 2038, and may be redeemed at our option on or after May 13, 2003, or earlier if various events occur. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption.

*Minority Interests*

*Coastal Securities Company Preferred Stock.* In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million. Quarterly cash dividends are being paid on the preferred stock at a rate based on LIBOR. The preferred shareholders are also entitled to participating dividends based on various refining margins. Coastal Securities may redeem the preferred stock for cash at the liquidation price plus accrued and unpaid dividends.

*Coastal Oil & Gas Resources Preferred Stock.* In 1999, Coastal Oil & Gas Resources, Inc., our wholly owned subsidiary, issued 50,000 shares of preferred stock for $50 million. The preferred shareholders are entitled to quarterly cash dividends at a rate based on LIBOR. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Oil & Gas Resources and the preferred shareholders are unable to agree to a new rate, Coastal Oil & Gas Resources must redeem the shares at $1,000 per share plus any accrued and unpaid dividends, or cause the preferred stock to be registered with the Securities and Exchange Commission and remarketed. Coastal Oil & Gas Resources also has the option to redeem all shares on any dividend rate reset date for $1,000 per share plus any accrued and unpaid preferred dividends.

*Coastal Limited Ventures Preferred Stock.* In 1999, Coastal Limited Ventures, Inc., our wholly owned subsidiary, issued 150,000 shares of preferred stock for $15 million. The preferred shareholders are entitled to quarterly cash dividends at an annual rate of 6%. The dividend rate is subject to renegotiation in 2004 and on each fifth anniversary thereafter. In the event Coastal Limited and the preferred shareholders are unable to agree to a new rate, the preferred shareholders may call for redemption of all of the preferred shares. The redemption price is $100 per share plus any accrued and unpaid preferred dividends thereon. Coastal Limited also has the option to redeem all shares on any rate reset date for $100 per share plus any accrued and unpaid preferred dividends.

*Consolidated Partnership.* In December 1999, Coastal Limited contributed assets to a limited partnership in exchange for a controlling general partnership interest. Limited interests in the partnership were issued to unaffiliated investors for $285 million. The limited partners are entitled to a cumulative priority return based on LIBOR. The return is subject to renegotiation in 2004 and on each fifth anniversary thereafter. The partnership has a maximum life of 20 years, but may be terminated sooner subject to certain conditions, including failure to agree to a new rate. Coastal Limited may terminate the partnership at any time by repayment of the limited partners' outstanding capital plus any unpaid priority returns.

## 13. Commitments and Contingencies

*Legal Proceedings*

In May 1999, one of our subsidiaries was named as a defendant in a suit filed in the 319th Judicial District Court, Nueces County, Texas by an individual employed by one of our contractors *(Rolando Lopez and Rosanna Barton v. Coastal Refining & Marketing, Inc. and The Coastal Corporation)*. The suit sought damages for injuries sustained at the time of an explosion at one of our refining plants, and was settled in August 2000 for a total payment of $7 million, of which $5 million was covered by insurance. Three of the refinery employees intervened in the suit and sought damages for injuries sustained in the explosion. Those claims were tried in August 2000, resulting in a $122 million verdict, for which there is insurance coverage. The case has been appealed to the Thirteenth Court of Appeals of Texas, and all appellate briefing in that court has been completed. Even if the verdict is upheld on appeal, it will not have a material adverse effect on our financial position, operating results or cash flows.

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 Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In October 1992, several property owners in McAllen, Texas, filed suit in the 93rd Judicial District Court, Hidalgo County, Texas, against, among others, one of our subsidiaries *(Timely Adventures, Inc., et al, v. Phillips Properties, Inc., et al* and *Garza v. Coastal Mart, Inc.)*. The suit sought damages for the alleged diminution of property value and damages related to the exposure to hazardous chemicals arising from the operation of service stations and storage facilities. In July 2000, the trial court entered a judgment for approximately $1.2 million in actual damages for property diminution and approximately $100 million in punitive damages. The judgment was appealed. An agreement in principle to settle this case has been reached, and we expect the settlement to be concluded in March 2002. We have established accruals that we believe are sufficient to provide for the settlement. The settlement will not have a material adverse effect on our financial position, operating results or cash flows.

In compliance with the 1990 amendments to the Clean Air Act (CAA), we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in five such lawsuits in New York. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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 $81 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 $260 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $199 million in the aggregate for the years 2002 through 2006. These expenditures primarily relate to compliance with clean air regulations. Our accrued amounts as of December 31, 2001 include a change in our estimated environmental remediation liabilities as a result of several events that occurred during 2001 and an evaluation of our operations following the El Paso merger. See a discussion of this change in estimate in Note 4.

From May 1999 to March 2001, our Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1.1 million for these alleged violations. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments and, concurrently, is in negotiations to settle these assessments.

In February 2002, we received a Notice of Violation from the EPA alleging noncompliance with the EPA's fuel regulations from 1996 to 1998. The notice proposes a penalty of $165,000 for these alleged violations. We are investigating the allegations and are preparing a response.

We have been designated, 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 16 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (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 approximately $5 million and $8 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 of 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 March 2001, CIG filed a rate case with the FERC proposing increased rates of $9 million annually and new and enhanced services for its customers. This filing was required under the settlement of its 1996 general rate case. CIG received an order from FERC in late April 2001, which suspended the rates until October 1, 2001, subject to refund, and subject to the outcome of an evidentiary hearing. On September 26, 2001, the FERC issued an order rejecting two firm services CIG had proposed in its rate filing and required it to reallocate the costs allocated to those two services to existing services. CIG has complied with this order and has arranged with the affected customers to provide service under existing rate schedules. The evidentiary hearing was suspended pending ongoing attempts to settle the case.

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. While we cannot predict the outcome of the NOPR, 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*

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 two power plants in Pakistan, with a total investment, including financial guarantees on these projects, of approximately $222 million. While we are aware of no specific threats or actions against these power plants, events in that region, including possible retaliation for American military actions, could impact these projects 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.

*Capital Commitments and Purchase Obligations*

At December 31, 2001, we had capital and investment commitments of $265 million primarily relating to our production, 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 totaling $269 million at December 31, 2001. Our annual obligations under these agreements are $24 million for the years 2002, 2003, 2004, 2005 and 2006, and $149 million in total thereafter.

*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 2031. As of December 31, 2001, our total commitments under operating leases were approximately $255 million.

Under several of our leases, we have provided residual value guarantees to the lessor. Under these guarantees, we can either choose to purchase the asset at the end of the lease term for a specified amount, which is typically equal to the outstanding loan amounts 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 guarantee, we would be obligated for the shortfall. The level of our residual value guarantees are 89.9 percent of the original cost of the leased assets. The total outstanding residual value guarantees on our operating leases at December 31, 2001, were $425 million.

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

| Year Ending December 31, | Operating Leases (In millions) |
|---|---|
| 2002 | $ 57 |
| 2003 | 47 |
| 2004 | 30 |
| 2005 | 18 |
| 2006 | 12 |
| Thereafter | 91 |
| Total | $255 |

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

Rental expenses for the years ended December 31, 2001, 2000 and 1999 was $92 million, $140 million and $120 million.

*Letters of Credit*

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2001, we had outstanding letters of credit of $166 million related to our marketing and trading activities, our domestic power development and other operating activities.

*Guarantees*

Our involvement in joint ventures and project level construction and finance results in the issuance of financial and non-financial guarantees in our business activities. We also guarantee performance and contractual commitments of companies within our consolidated group. There are various events and circumstances that may require us to perform under our guarantees, including:

- non-payment by the guaranteed party;
- non-compliance with the covenants of the transactions by the guaranteed party;
- non-compliance by us with the provision of guarantees; and
- cross-acceleration with other transactions.

As of December 31, 2001, we had approximately $8 million of guarantees in connection with our international development and operating activities not consolidated on our balance sheet and approximately $162 million of guarantees in connection with our domestic development and operating activities not consolidated on our balance sheet.

## 14. 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 except for employees of our coal and retail operations who are covered under a separate plan. Also, El Paso maintains a defined contribution plan covering its U.S. employees, including our employees. El Paso matches 75 percent of participant basic contributions of up to 6 percent, with the matching contribution being made to the plan's stock fund. Participants can elect to move the matching contribution at any time into any of the seven remaining funds or leave them in the stock fund. El Paso is responsible for benefits accrued under its plan and allocates the related costs to its affiliates.

Prior to the merger, we maintained both defined benefit and defined contribution plans. Our pension plan covered substantially all of our U.S. employees. On April 1, 2001, this primary plan was merged into El Paso's existing plan. Our employees who were participants in our primary plan on March 31, 2001 receive the greater of cash balance benefits or our plan benefits accrued through March 31, 2006. In addition, we maintained a defined contribution plan. Under this plan, we matched 100 percent of basic contributions of up to 8 percent with matching contributions made in our common stock. Amounts expensed under this plan were $21 million and $20 million for the years ended December 31, 2000 and 1999.

*Other Postretirement Benefits*

As a result of our merger with El Paso, El Paso offered a one-time election through an early retirement window for employees who were at least age 50 with 10 years of service on December 31, 2000, to retire on or before June 30, 2001 and keep benefits under our postretirement medical and life plans. The costs associated with the curtailment and special termination benefits were $65 million. Medical benefits for this closed group of retirees may be subject to deductibles, co-payment provisions and other limitations and dollar caps on the amount of employer costs. El Paso has reserved the right to change these benefits. Employees who retire on or after June 30, 2001 will continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are pre-funded to the extent such costs are recoverable through rates.

In January 2001, following our merger we changed the measurement dates for measuring our pension and other postretirement benefit obligations from December 31 to September 30. We made this change to conform our measurement dates to the dates El Paso uses to measure pension and other postretirement benefit obligations. The new method is consistent with the manner in which El Paso gathers pension and other postretirement benefit information and will facilitate ease of planning and reporting in a more timely manner. We believe this method is preferable to the method previously employed. We accounted for this as a change in accounting principle, and it had no material effect on retirement benefit expense for the current or prior periods.

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 pension benefits and other postretirement benefits. Our benefits are presented and computed as of and for the twelve months ended December 31, 2000 and September 30, 2001.

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Change in benefit obligation | | | | |
| Benefit obligation at beginning of period | $ 822 | $ 777 | $114 | $108 |
| Service cost | 5 | 21 | 1 | 3 |
| Interest cost | 20 | 59 | 9 | 8 |
| Participant contributions | — | — | 3 | 2 |
| Plan amendment | — | — | (12) | — |
| Curtailment and special termination benefit | 137 | — | 16 | — |
| Actuarial loss or (gain) | 75 | 10 | (15) | 3 |
| Benefits paid | (13) | (45) | (7) | (10) |
| Transfer of plan obligations | (962) | — | — | — |
| Benefit obligation at end of period | $ 84 | $ 822 | $109 | $114 |

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Change in plan assets | | | | |
| Fair value of plan assets at beginning of period | $1,971 | $1,662 | $ 35 | $ 29 |
| Actual return on plan assets | (182) | 354 | 1 | 1 |
| Employer contributions | — | — | 8 | 11 |
| Participant contributions | — | — | 3 | — |
| Benefits paid | (13) | (45) | (7) | (6) |
| Transfer of plan assets | (1,679) | — | — | — |
| Fair value of plan assets at end of period | $ 97 | $1,971 | $ 40 | $ 35 |
| Reconciliation of funded status | | | | |
| Funded status at end of period | $ 13 | $1,149 | $(69) | $(79) |
| Fourth quarter contributions | — | | 3 | |
| Unrecognized net actuarial gain | 14 | (528) | (28) | (27) |
| Unrecognized net transition obligation | — | (12) | — | 71 |
| Unrecognized prior service cost | — | 4 | — | 3 |
| Other | 1 | — | — | — |
| Accrued benefit cost at December 31, | $ 28 | $ 613 | $(94) | $(32) |

| | Pension Benefits | | | Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | 2001 | 2000 | 1999 | 2001 | 2000 | 1999 |
| | (In millions) | | | | | |
| Benefit cost for the plans includes the following components | | | | | | |
| Service cost | $ 5 | $ 21 | $ 21 | $ 1 | $ 3 | $ 3 |
| Interest cost | 20 | 59 | 52 | 9 | 8 | 7 |
| Expected return on plan assets | (55) | (164) | (146) | (2) | (1) | (1) |
| Amortization of net actuarial gain | (9) | (20) | (13) | — | (2) | (2) |
| Amortization of transition obligation | (2) | (8) | (8) | — | 6 | 6 |
| Amortization of prior service cost | — | 1 | 1 | — | 1 | — |
| Curtailment and special termination benefit | 137 | — | — | 65 | — | — |
| Net benefit cost | $ 96 | $(111) | $ (93) | $73 | $15 | $13 |

Benefit obligations are based upon actuarial estimates as described below.

| | Pension Benefits | | Postretirement Benefits | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| Weighted average assumptions | | | | |
| Discount rate | 7.25% | 7.75% | 7.25% | 7.75% |
| Expected return on plan assets | 10.00% | 10.00% | 7.50% | 4.60% |
| Rate of compensation increase | 4.00% | 4.00% | — | — |

Actuarial estimates for our postretirement benefits plans assumed a weighted average annual rate of increase in the per capita costs for 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 from assumed health care cost trends would have the following effects:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| One Percentage Point Increase | | |
| Aggregate of service cost and interest cost | $ — | $ — |
| Accumulated postretirement benefit obligation | $ 3 | $ 6 |
| One Percentage Point Decrease | | |
| Aggregate of service cost and interest cost | $ — | $ — |
| Accumulated postretirement benefit obligation | $ (3) | $ (6) |

## 15. Segment and Geographic Reporting

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Production 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 historical segments (natural gas systems; refining, marketing and chemicals; exploration and production; power; and coal) have been restated and included in the segments in which these businesses were managed and operated following the merger. All prior periods have been restated to reflect this presentation. The results presented in this analysis are not necessarily indicative of the results that would have been achieved had the revised business segment structure been in effect during those periods.

Our Pipelines segment provides natural gas transmission services in the U.S. and internationally. We conduct our activities through three wholly owned and three partially owned interstate transmission systems along with five underground natural gas storage facilities. Our pipeline operations also include access between our U.S. based systems and Canada.

Our Merchant Energy segment is involved in a broad range of energy-related activities, including asset ownership and marketing and trading activities. We buy, sell and trade natural gas, power, crude oil, refined products, coal and other energy commodities and own or have interests in 18 power generation plants in 8 countries.

Our Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. Production has onshore and coal seam operations and properties in 14 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

Our Field Services segment provides wellhead-to-mainline services, including natural gas gathering, products extraction, fractionation, dehydration, purification, compression and transportation of natural gas and natural gas liquids. Field Services' assets are located in the Rocky Mountains, east and south Texas and Louisiana.

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 have chosen to evaluate segment performance based on EBIT instead of operating income. To the extent practicable, results of operations for the years ended December 31, 2000 and 1999 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 | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | | | | | | |
| Domestic | $ 980 | $18,063 | $1,772 | $822 | $ 355 | $21,992 |
| Foreign | 2 | 3,662 | 46 | 4 | — | 3,714 |
| Intersegment revenue | 70 | 335 | (35) | 68 | (438) | — |
| Merger-related costs and asset impairment charges | 217 | 169 | 61 | 13 | 526 | 986 |
| Ceiling test charges | — | — | 115 | — | — | 115 |
| Depreciation, depletion and amortization | 137 | 103 | 453 | 15 | 21 | 729 |
| Operating income (loss) | 192 | (210) | 785 | 55 | (710) | 112 |
| Other income | 100 | 199 | 6 | 16 | 12 | 333 |
| EBIT | 292 | (11) | 791 | 71 | (698) | 445 |
| Extraordinary items, net of income taxes | — | (7) | — | (4) | — | (11) |
| Assets | | | | | | |
| Domestic | 5,467 | 2,845 | 5,761 | 529 | 197 | 14,799 |
| Foreign | 14 | 3,431 | 773 | 17 | 32 | 4,267 |
| Capital expenditures and investments in unconsolidated affiliates | 421 | 333 | 1,814 | 53 | 1 | 2,622 |
| Total investments in unconsolidated affiliates | 547 | 1,041 | 110 | 168 | 17 | 1,883 |

| | Segments As of or for the Year Ended December 31, 2000 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | | | | | | |
| Domestic | $ 972 | $19,981 | $ 806 | $709 | $1,191 | $23,659 |
| Foreign | — | 3,270 | 5 | 2 | — | 3,277 |
| Intersegment revenue | 73 | 334 | 320 | 44 | (771) | — |
| Merger-related costs and asset impairment charges | — | 21 | — | — | 13 | 34 |
| Depreciation, depletion and amortization | 132 | 88 | 399 | 8 | 30 | 657 |
| Operating income | 388 | 118 | 417 | 86 | 44 | 1,053 |
| Other income (loss) | 112 | 248 | (4) | 25 | 34 | 415 |
| EBIT | 500 | 366 | 413 | 111 | 78 | 1,468 |
| Assets | | | | | | |
| Domestic | 5,182 | 5,278 | 4,038 | 512 | 1,424 | 16,434 |
| Foreign | 83 | 2,086 | 198 | 17 | 57 | 2,441 |
| Capital expenditures and investments in unconsolidated affiliates | 232 | 229 | 1,583 | 45 | 23 | 2,112 |
| Total investments in unconsolidated affiliates | 609 | 794 | — | 193 | 17 | 1,613 |

(1) Includes Corporate and eliminations as well as retail operations.

| | Segments As of or for the Year Ended December 31, 1999 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[1] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | | | | | | |
| Domestic | $ 919 | $11,879 | $ 576 | $276 | $1,049 | $14,699 |
| Foreign | — | 1,889 | 8 | — | — | 1,897 |
| Intersegment revenue | 67 | 359 | 28 | 25 | (479) | — |
| Depreciation, depletion and amortization | 133 | 84 | 239 | 7 | 30 | 493 |
| Operating income | 385 | 93 | 171 | 33 | 61 | 743 |
| Other income | 96 | 166 | 1 | 12 | 10 | 285 |
| EBIT | 481 | 259 | 172 | 45 | 71 | 1,028 |
| Assets | | | | | | |
| Domestic | 5,116 | 3,456 | 2,959 | 385 | 1,253 | 13,169 |
| Foreign | 53 | 2,055 | 74 | — | 72 | 2,254 |
| Capital expenditures and investments in unconsolidated affiliates | 230 | 351 | 1,082 | 77 | 41 | 1,781 |
| Total investments in unconsolidated affiliates | 602 | 663 | — | 172 | (2) | 1,435 |

(1) Includes Corporate and eliminations as well as retail operations.

The reconciliations of EBIT to income before extraordinary items are presented below for the years ended December 31:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | (In millions) | | |
| Total EBIT for segments | $ 445 | $1,468 | $1,028 |
| Non-affiliated interest and debt expense | (447) | (502) | (323) |
| Affiliated interest expense, net | (46) | — | — |
| Minority interest | (51) | (60) | (32) |
| Income taxes | (78) | (252) | (174) |
| Income (loss) before extraordinary items | $(177) | $ 654 | $ 499 |

We had no customers whose revenues exceeded 10 percent of our total revenues in 2001, 2000 and 1999.

## 16. 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 | $ 589 | $ 389 | $ 307 |
| Income tax payments | 77 | 70 | 10 |

## 17. 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 $22 million and $20 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) | | | |
| United States | | | | | | |
| Alliance Pipeline Limited Partnership | | 14% | $ 160 | $ 216 | $— | $— |
| Aux Sable Liquid | | 14% | 58 | 56 | — | — |
| Bastrop Company, LLC | | 50% | 99 | 33 | — | — |
| Eagle Point Cogeneration Partnership | | 84% | 85 | 34 | — | — |
| Great Lakes Gas Transmission LP | | 50% | 297 | 291 | — | — |
| Javelina Company | | 40% | 48 | 55 | — | — |
| Midland Cogeneration Venture | | 44% | 276 | 198 | — | — |
| Noric Holdings I, LLC[(1)] | | 41% | 110 | — | — | — |
| Other Domestic Investments[(2)] | | various | 297 | 293 | — | — |
| Total United States | | | 1,430 | 1,176 | — | — |
| Foreign | | | | | | |
| EGE Fortuna | Panama | 24% | 56 | 53 | — | — |
| Empresa Generadora de Electridad (Itabo) | Dominican Republic | 25% | 101 | 99 | — | — |
| Habibullah Power | Pakistan | 50% | 53 | 53 | — | — |
| Other Foreign Investments[(1)] | | various | 243 | 232 | 59 | 72 |
| Total Foreign | | | 453 | 437 | 59 | 72 |
| Total investments in and advances to unconsolidated affiliates | | | $1,883 | $1,613 | $59 | $72 |

(1) In June 2001, we conveyed oil and gas properties to an affiliate for an equity investment of 26 percent. In December 2001, we conveyed additional properties which increased our ownership percentage to 41 percent.

(2) Denotes investments less than $50 million.

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

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Alliance Pipeline Limited Partnership | $ 23 | $ 12 | $ 10 |
| Eagle Point Cogeneration Partnership | 22 | 25 | 22 |
| Empire State Pipeline | 3 | 8 | 9 |
| Empresa Generadora de Electricidad (Itabo) | 5 | 9 | 3 |
| Engage Energy US, LP and Engage Energy Canada, LP (through September 2000) | — | 11 | 5 |
| Great Lakes Gas Transmission LP | 55 | 52 | 52 |
| Iroquois Gas Pipeline System, LP | 3 | 7 | 6 |
| Javelina Company | (1) | 17 | 10 |
| Midland Cogeneration Venture | 23 | 37 | 16 |
| Mohawk River Funding IV, LLC | 47 | — | — |
| Noric Holdings I, LLC | 4 | — | — |
| Other | 39 | 87 | 57 |
| | $223 | $265 | $190 |

As discussed in Note 2, we have divested our ownership interest in the Empire State, Iroquois, Stingray and U-T offshore pipeline systems.

In October 2000, we terminated the Engage joint venture that was formed in 1997. As a result, the operations were divided into separate entities that are owned and operated independently by each former joint venture partner.

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 $38 million and $48 million for December 31, 2001 and 2000 and total assets of $760 million and $542 million for December 31, 2001 and 2000.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | | (Unaudited) (In millions) | |
| Operating results data: | | | |
| Revenues and other income | $1,326 | $3,829 | $3,345 |
| Costs and expenses | 1,103 | 3,459 | 3,107 |
| Income from continuing operations | 223 | 370 | 238 |
| Net income | 223 | 241 | 196 |

| | December 31, | |
|---|---|---|
| | 2001 | 2000 |
| | (Unaudited) (In millions) | |
| Financial position data: | | |
| Current assets | $ 576 | $ 717 |
| Non-current assets | 3,508 | 3,288 |
| Short-term debt | 228 | 207 |
| Other current liabilities | 249 | 412 |
| Long-term debt | 1,524 | 1,654 |
| Other non-current liabilities | 279 | 123 |
| Equity in net assets | 1,804 | 1,609 |

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

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In millions) | |
| Revenues | $1,880 | $1,154 | $559 |
| Cost of sales | 248 | 314 | 140 |
| Reimbursement for costs | 3 | 4 | 4 |
| Charges from affiliates | 337 | — | — |
| Capitalization of charges from affiliates | 50 | — | — |

We enter into transactions with other El Paso subsidiaries and unconsolidated affiliates in the ordinary course of business to transport, sell and purchase natural gas and various contractual agreements for trading activities. Prior to October 2000, we had significant activities with Engage Energy. During the fourth quarter of 2000, we terminated the Engage joint venture and assumed the U.S. portion of Engage. In February 2001, we transferred our natural gas and power trading activities to El Paso Merchant Energy, an affiliate and subsidiary of El Paso, in exchange for a 22 percent interest in El Paso Merchant Energy, L.P. The transfer was based on estimated fair value of contracts transferred, and the investment was accounted for on a cost basis. In September 2001, we redeemed this interest. As a result, operational related party transactions that had previously been with an unconsolidated affiliate are now with an affiliate. In addition, other operational affiliated transactions have increased due to the El Paso merger.

As a result of the El Paso merger, during 2001, El Paso and its subsidiaries provided some operational, financial, accounting and administrative services for 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. We believe the allocation methods are reasonable. Our Production segment capitalizes a portion of the allocated costs to the full cost pool based on net property, and it is reflected as a reduction of operation expenses.

Effective with the merger with El Paso, we now 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 $932 million at December 31, 2001, at a market rate of interest which was 2.1%. In addition, we have a demand note receivable with El Paso of $120 million at December 31, 2001, with an interest rate of 4.2%.

At December 31, 2001, we had current account and note receivables from related parties of $426 million and $88 million at December 31, 2000. In addition, we had a non-current note receivable of $27 million included in other non-current assets at December 31, 2001, and $31 million at December 31, 2000. Also, at December 31, 2001, we had account and note payables from related parties of $428 million and $13 million at December 31, 2000.

## 18. 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[1] | $5,520 | $6,415 | $5,974 | $7,797 |
| Merger-related costs and asset impairment charges | (13) | 15 | 217 | 767 |
| Ceiling test charges | — | 115 | — | — |
| Operating income (loss)[1] | 304 | 126 | (18) | (300) |
| Income (loss) before extraordinary items | 188 | 40 | (68) | (337) |
| Extraordinary items, net of income taxes | — | (4) | 3 | (10) |
| Net income (loss) | 188 | 36 | (65) | (347) |
| 2000 | | | | |
| Operating revenues | $8,748 | $6,450 | $6,123 | $5,615 |
| Merger-related costs and asset impairment charges | 24 | 3 | 3 | 4 |
| Operating income | 299 | 272 | 219 | 263 |
| Income before extraordinary items | 207 | 145 | 128 | 174 |
| Net income | 207 | 145 | 128 | 174 |

(1) Adjustments were made to conform our accounting presentation to El Paso's presentation and include reclassifications to conform to El Paso's current presentation. These reclassifications had no impact on our net income or retained earnings.

## 19. Supplemental Natural Gas and Oil Operations (Unaudited)

At December 31, 2001, we had interests in natural gas and oil properties in 14 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have a limited number of natural gas and oil properties in Brazil, Canada and Indonesia as well as exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary and Indonesia.

For purposes of the Supplemental Natural Gas and Oil Operations disclosure, we have presented reserves, standardized measure of discounted future net cash flows and the related changes in standardized measure separately for natural gas systems operations which includes the natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries. The Supplemental Natural Gas and Oil Operations disclosure does not include any value for storage gas and liquids volumes managed by our pipeline segment.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

| | United States | Canada | Other Countries[1] | Worldwide |
|---|---|---|---|---|
| 2001 | | | | |
| Natural gas and oil properties: | | | | |
| Costs subject to amortization | $6,394 | $415 | $ 72 | $6,881 |
| Costs not subject to amortization | 494 | 250 | 49 | 793 |
| | 6,888 | 665 | 121 | 7,674 |
| Less accumulated DD&A | 2,316 | 170 | 31 | 2,517 |
| Net capitalized costs | $4,572 | $495 | $ 90 | $5,157 |
| 2000 | | | | |
| Natural gas and oil properties: | | | | |
| Costs subject to amortization | $4,168 | $114 | $ — | $4,282 |
| Costs not subject to amortization | 667 | 32 | 12 | 711 |
| | 4,835 | 146 | 12 | 4,993 |
| Less accumulated DD&A | 985 | 1 | — | 986 |
| Net capitalized costs | $3,850 | $145 | $ 12 | $4,007 |

[1] Includes International operations in Brazil and Indonesia.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31 (in millions):

| | United States | Canada | Other Countries[1] | Worldwide |
|---|---|---|---|---|
| 2001 | | | | |
| Property acquisition costs | | | | |
| Proved properties | $ 87 | $232 | $— | $ 319 |
| Unproved properties | 33 | 16 | 25 | 74 |
| Exploration costs | 110 | 19 | 58 | 187 |
| Development costs | 1,025 | 105 | 14 | 1,144 |
| Total costs incurred | $1,255 | $372 | $97 | $1,724 |
| 2000 | | | | |
| Property acquisition costs | | | | |
| Proved properties | $ 127 | $ 3 | $— | $ 130 |
| Unproved properties | 130 | 6 | — | 136 |
| Exploration costs | 193 | 42 | 11 | 246 |
| Development costs | 961 | 69 | — | 1,030 |
| Total costs incurred | $1,411 | $120 | $11 | $1,542 |
| 1999 | | | | |
| Property acquisition costs | | | | |
| Proved properties | $ 154 | $ — | $— | $ 154 |
| Unproved properties | 142 | 10 | — | 152 |
| Exploration costs | 150 | 11 | — | 161 |
| Development costs | 588 | 5 | — | 593 |
| Total costs incurred | $1,034 | $ 26 | $— | $1,060 |

[1] Includes International operations in Brazil and Indonesia.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2001, pending determination of proved reserves.

Capitalized interest of $47 million, $25 million, and $2 million for the years ended December 31, 2001, 2000 and 1999 is included in the presentation below (in millions):

| | Cumulative Balance December 31, | Costs Excluded for Years Ended December 31, | | | Cumulative Balance December 31, |
|---|---|---|---|---|---|
| | 2001 | 2001 | 2000 | 1999 | 1998 |
| Worldwide | | | | | |
| Acquisition | $599 | $330 | $110 | $ 70 | $ 89 |
| Exploration | 88 | 27 | 46 | 11 | 4 |
| Development | 106 | 30 | 35 | 23 | 18 |
| | $793 | $387 | $191 | $104 | $111 |

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2002 through 2005. Total amortization expense per Mcfe, including ceiling test charges, was $1.29, $1.05, and $0.87 in 2001, 2000, and 1999. Excluding ceiling test charges, amortization expense would have been $1.03 per Mcfe in 2001. Depreciation, depletion, and amortization excludes provisions for the impairment of international projects of $15 million in 2000 and $10 million in 1999.

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves are presented below. These reserves include 124,158, 197,782 and 259,342 MMcfe of production delivery commitments under financing arrangements that extend through 2005. Total proved reserves on the fields with this dedicated production were 1,981,239 MMcfe.

| | Natural Gas (in Bcf) | | | | |
|---|---|---|---|---|---|
| | United States | Canada | Other Countries[(1)] | Worldwide | Natural Gas Systems[(2)] |
| Net proved developed and undeveloped reserves[(3)] | | | | | |
| January 1, 1999 | 2,316 | — | — | 2,316 | 212 |
| Revisions of previous estimates | (61) | — | — | (61) | 22 |
| Extensions, discoveries and other | 746 | 73 | — | 819 | — |
| Purchases of reserves in place | 539 | — | — | 539 | — |
| Sales of reserves in place | (40) | — | — | (40) | — |
| Production | (231) | — | — | (231) | (36) |
| December 31, 1999 | 3,269 | 73 | — | 3,342 | 198 |
| Revisions of previous estimates | (203) | (62) | — | (265) | 11 |
| Extensions, discoveries and other | 802 | 155 | 91 | 1,048 | — |
| Purchases of reserves in place | 499 | 2 | — | 501 | — |
| Sales of reserves in place | (19) | — | — | (19) | — |
| Production | (328) | (1) | — | (329) | (33) |
| December 31, 2000 | 4,020 | 167 | 91 | 4,278 | 176 |
| Revisions of previous estimates | (996) | (136) | (51) | (1,183) | 37 |
| Extensions, discoveries and other | 604 | 85 | — | 689 | — |
| Purchases of reserves in place | 103 | 83 | — | 186 | — |
| Sales of reserves in place | — | — | — | — | — |
| Production | (373) | (13) | — | (386) | (30) |
| December 31, 2001 | 3,358 | 186 | 40 | 3,584 | 183 |
| Proved developed reserves | | | | | |
| December 31, 1999 | 1,626 | 27 | — | 1,653 | 198 |
| December 31, 2000 | 1,816 | 112 | — | 1,928 | 176 |
| December 31, 2001 | 1,613 | 138 | — | 1,751 | 183 |

(1) Includes International operations in Brazil and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

(3) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

| | Liquids[1] (in MBbls) | | | | |
|---|---|---|---|---|---|
| | United States | Canada | Other Countries[2] | Worldwide | Natural Gas Systems[3] |
| Net proved developed and undeveloped reserves[4] | | | | | |
| January 1, 1999 | 52,047 | — | — | 52,047 | 237 |
| Revisions of previous estimates | (6,620) | — | — | (6,620) | 36 |
| Extensions, discoveries and other | 5,354 | 867 | — | 6,221 | — |
| Purchases of reserves in place | 11,377 | — | — | 11,377 | — |
| Sales of reserves in place | (805) | — | — | (805) | — |
| Production | (4,475) | — | — | (4,475) | (24) |
| December 31, 1999 | 56,878 | 867 | — | 57,745 | 249 |
| Revisions of previous estimates | 238 | (544) | — | (306) | 7 |
| Extensions, discoveries and other | 8,231 | 3,600 | 4,862 | 16,693 | — |
| Purchases of reserves in place | 6,546 | 13 | — | 6,559 | — |
| Sales of reserves in place | (609) | — | — | (609) | — |
| Production | (6,477) | (13) | — | (6,490) | (25) |
| December 31, 2000 | 64,807 | 3,923 | 4,862 | 73,592 | 231 |
| Revisions of previous estimates | 25,140 | (4,224) | (4,862) | 16,054 | (118) |
| Extensions, discoveries and other | 24,843 | 1,173 | 7,771 | 33,787 | — |
| Purchases of reserves in place | 101 | 10,570 | — | 10,671 | — |
| Sales of reserves in place | — | — | — | — | — |
| Production | (8,227) | (560) | — | (8,787) | (16) |
| December 31, 2001 | 106,664 | 10,882 | 7,771 | 125,317 | 97 |
| Proved developed reserves | | | | | |
| December 31, 1999 | 33,690 | 312 | — | 34,002 | 249 |
| December 31, 2000 | 36,404 | 2,723 | — | 39,127 | 231 |
| December 31, 2001 | 62,704 | 7,341 | — | 70,045 | 97 |

(1) Includes oil, condensate and natural gas liquids.

(2) Includes International operations in Brazil and Indonesia.

(3) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

(4) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner.

The significant changes to reserves, other than purchases, sales or production, are due to reservoir performance in existing fields and from drilling additional wells in existing fields. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2001.

Results of operations from producing activities by fiscal year were as follows at December 31 (in millions):

| | United States | Canada | Other Countries[1] | Worldwide |
|---|---|---|---|---|
| **2001** | | | | |
| Net Revenues | | | | |
| Sales to external customers | $ 391 | $ 45 | $ — | $ 436 |
| Affiliated sales | 1,484 | 1 | — | 1,485 |
| Total | 1,875 | 46 | — | 1,921 |
| Production costs | (210) | (12) | — | (222) |
| Depreciation, depletion and amortization | (435) | (17) | — | (452) |
| Ceiling test charges | — | (87) | (28) | (115) |
| | 1,230 | (70) | (28) | 1,132 |
| Income tax (expense) benefit | (430) | 25 | (9) | (414) |
| Results of operations from producing activities (excluding corporate overhead and interest costs) | $ 800 | $(45) | $(37) | $ 718 |
| **2000** | | | | |
| Net Revenues | | | | |
| Sales to external customers | $ 867 | $ 6 | $ — | $ 873 |
| Affiliated sales | 214 | — | — | 214 |
| Total | 1,081 | 6 | — | 1,087 |
| Production costs | (236) | (1) | — | (237) |
| Depreciation, depletion and amortization | (372) | (1) | — | (373) |
| | 473 | 4 | — | 477 |
| Income tax (expense) benefit | (160) | (2) | — | (162) |
| Results of operations from producing activities (excluding corporate overhead and interest costs) | $ 313 | $ 2 | $ — | $ 315 |
| **1999** | | | | |
| Net Revenues | | | | |
| Sales to external customers | $ 451 | $ — | $ — | $ 451 |
| Affiliated sales | 113 | — | — | 113 |
| Total | 564 | — | — | 564 |
| Production costs | (154) | — | — | (154) |
| Depreciation, depletion and amortization | (223) | — | — | (223) |
| | 187 | — | — | 187 |
| Income tax (expense) benefit | (59) | — | — | (59) |
| Results of operations from producing activities (excluding corporate overhead and interest costs) | $ 128 | $ — | $ — | $ 128 |

(1) Includes international operations in Brazil and Indonesia.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31 (in millions):

| | United States | Canada | Other Countries[1] | Worldwide | Natural Gas Systems[2] |
|---|---|---|---|---|---|
| **2001** | | | | | |
| Future cash inflows | $10,499 | $ 641 | $ 253 | $11,393 | $ 313 |
| Future production and development costs | (3,083) | (279) | (124) | (3,486) | (64) |
| Future income tax expenses | (1,675) | (8) | (23) | (1,706) | (83) |
| Future net cash flows | 5,741 | 354 | 106 | 6,201 | 166 |
| 10% annual discount for estimated timing of cash flows | (2,380) | (143) | (52) | (2,575) | (72) |
| Standardized measure of discounted future net cash flows | $ 3,361 | $ 211 | $ 54 | $ 3,626 | $ 94 |
| **2000** | | | | | |
| Future cash inflows | $27,535 | $ 1,597 | $ 397 | $29,529 | $ 474 |
| Future production and development costs | (5,064) | (171) | (209) | (5,444) | (110) |
| Future income tax expenses | (7,014) | (599) | (60) | (7,673) | (116) |
| Future net cash flows | 15,457 | 827 | 128 | 16,412 | 248 |
| 10% annual discount for estimated timing of cash flows | (6,522) | (469) | (109) | (7,100) | (89) |
| Standardized measure of discounted future net cash flows | $ 8,935 | $ 358 | $ 19 | $ 9,312 | $ 159 |
| **1999** | | | | | |
| Future cash inflows | $ 8,250 | $ — | $ — | $ 8,250 | $ 229 |
| Future production and development costs | (2,674) | — | — | (2,674) | (74) |
| Future income tax expenses | (1,265) | — | — | (1,265) | (49) |
| Future net cash flows | 4,311 | — | — | 4,311 | 106 |
| 10% annual discount for estimated timing of cash flows | (1,556) | — | — | (1,556) | (41) |
| Standardized measure of discounted future net cash flows | $ 2,755 | — | — | $ 2,755 | $ 65 |

(1) Includes international operations in Brazil and Indonesia.
(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end market natural gas and oil prices. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions and corporate investment criteria.

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in millions):

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2001 | | 2000 | | 1999 | |
| | Exploration and Production(1) | Natural Gas Systems(2) | Exploration and Production | Natural Gas Systems | Exploration and Production | Natural Gas Systems |
| Sales and transfers of natural gas and oil produced net of production costs | $(1,699) | $ (255) | $(1,300) | $ (52) | $ (474) | $ (36) |
| Net changes in prices and production costs | (7,659) | 10 | 6,697 | 150 | 734 | (6) |
| Extensions, discoveries and improved recovery, less related costs | 767 | — | 3,586 | — | 606 | — |
| Changes in estimated future development costs | (20) | 13 | — | — | — | — |
| Development costs incurred during the period | 338 | — | 83 | — | 102 | — |
| Revisions of previous quantity estimates | (1,188) | 39 | (693) | 34 | (235) | 28 |
| Accretion of discount | 1,308 | 23 | 194 | 4 | 136 | 7 |
| Net change in income taxes | 2,876 | 25 | (3,337) | (42) | (307) | 3 |
| Purchases of reserves in place | 223 | — | 1,292 | — | 643 | — |
| Sales of reserves in place | — | — | (14) | — | (33) | — |
| Changes in production rates, timing and other | (631) | 80 | 49 | — | — | — |
| Net change | $(5,685) | $ (65) | $ 6,557 | $ 94 | $ 1,172 | $ (4) |

(1) Includes operations in the United States, Canada, Brazil and Indonesia.

(2) Includes natural gas and oil properties owned by Colorado Interstate Gas Company and its subsidiaries.

## REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of
El Paso CGP Company:

In our opinion, the consolidated financial statements in the Index appearing under Item 14(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso CGP Company as of December 31, 2001, and the consolidated results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2001 listed in the index 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 the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 8, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* on January 1, 2001.

As discussed in Note 14, the Company changed the measurement dates used to account for pensions and postretirement benefits other than pensions from December 31 to September 30.

We also audited the adjustments described in Note 15 that were applied to restate the disclosures of 2000 and 1999 segment information in the accompanying financial statements to give retroactive effect to the change in reportable segments. In our opinion, such adjustments are appropriate and have been properly applied to the prior period financial statements.

PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2002

## INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholder of
El Paso CGP Company
Houston, Texas

We have audited the consolidated balance sheets of El Paso CGP Company (formerly The Coastal Corporation) and subsidiaries as of December 31, 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2000. Our audits also included the financial statement schedule listed in the Index at Item 14(a)2. 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 based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of El Paso CGP Company and subsidiaries as of December 31, 2000, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Houston, Texas
March 19, 2001

## SCHEDULE II

## EL PASO CGP COMPANY AND SUBSIDIARIES

## 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 and Other | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| 2001 | | | | | |
| Allowance for doubtful accounts | $19 | $ 23 | $ — | $ (6)[1] | $ 36 |
| Legal reserves | 32 | 50[2] | — | (1) | 81 |
| Environmental reserves | 28 | 242[2] | — | (10) | 260 |
| Regulatory reserves | — | 5 | — | — | 5 |
| Planned major maintenance accrual | 51 | (1)[3] | — | (14) | 36 |
| 2000 | | | | | |
| Allowance for doubtful accounts | $32 | $ 3 | $(14) | $ (2)[1] | $ 19 |
| Legal reserves | 48 | (14)[4] | — | (2) | 32 |
| Environmental reserves | 27 | 10 | — | (9) | 28 |
| Regulatory reserves | 8 | 2 | — | (10) | — |
| Planned major maintenance accrual | 34 | 33 | — | (16) | 51 |
| 1999 | | | | | |
| Allowance for doubtful accounts | $33 | $ 6 | $ (6) | $ (1)[1] | $ 32 |
| Legal reserves | 44 | 6 | — | (2) | 48 |
| Environmental reserves | 30 | 1 | — | (4) | 27 |
| Regulatory reserves | 6 | 2 | — | — | 8 |
| Planned major maintenance accrual | 25 | 26 | — | (17) | 34 |

(1) Primarily accounts written off.

(2) These amounts primarily relate to additional liabilities recorded in connection with changes in our estimates of these liabilities. See Note 4 for a further discussion of this change.

(3) During 2001, we accrued $23 million of reserves. In June, we leased our Corpus Christi refinery to Valero, and as a result we reversed $24 million of reserves.

(4) Includes reversal of $16 million of legal reserves due to a favorable resolution of natural gas price-related contingencies.

## 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;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Management;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

## PART IV

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

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

1. Financial statements.

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



The following financial statements of our equity investments are included on the following pages of this report:



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



Schedules other than those listed above are omitted because they are not applicable.

**MOHAWK RIVER FUNDING IV, L.L.C.**

**FINANCIAL STATEMENTS**
**WITH REPORT OF INDEPENDENT ACCOUNTANTS**
**DECEMBER 31, 2001**

**MOHAWK RIVER FUNDING IV, L.L.C.**

**REPORT OF INDEPENDENT ACCOUNTANTS**

To the Members of Mohawk River Funding IV, L.L.C.:

In our opinion, the accompanying balance sheet and the related statement of income, of members' equity and of cash flows present fairly, in all material respects, the financial position of Mohawk River Funding IV, L.L.C. (the "Company", and formerly known as Poquonock River Funding, L.L.C.) at December 31, 2001, and the results of its operations and its cash flows for the period from inception (August 2, 2001) to December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

As discussed in Note 3, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities,* on the date of inception (August 2, 2001).

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 27, 2002

## MOHAWK RIVER FUNDING IV, L.L.C.

## STATEMENT OF INCOME

### For the Period from Inception (August 2, 2001) to December 31, 2001
### (In thousands)

| | |
|---|---|
| Operating revenues | |
| Electricity sales | $ 5,438 |
| Operating expenses | |
| Electricity purchases from affiliate | 1,651 |
| Change in market value of power agreements, net | 4,221 |
| | 5,872 |
| Operating loss | (434) |
| Other income | |
| Initial market gain on power agreements, net | 75,948 |
| Net income | $ 75,514 |

See accompanying notes.

**MOHAWK RIVER FUNDING IV, L.L.C.**

**BALANCE SHEET**

**As of December 31, 2001**
**(In thousands)**

**ASSETS**

| | |
|---|---|
| Current assets | |
| Cash and cash equivalents | $ — |
| Amended power purchase agreement | 17,591 |
| Total current assets | 17,591 |
| Amended power purchase agreement | 94,711 |
| Total assets | $112,302 |

**LIABILITIES AND MEMBERS' CAPITAL**

| | |
|---|---|
| Current liabilities | |
| Accounts payable — affiliate | $ 1,651 |
| Accounts payable — Connecticut Light and Power | 8,767 |
| Mirror power purchase agreement — affiliate | 1,553 |
| Total current liabilities | 11,971 |
| Mirror power purchase agreement — affiliate | 7,291 |
| Commitments and contingencies | |
| Members' capital | 93,040 |
| Total liabilities and members' capital | $112,302 |

See accompanying notes.

## MOHAWK RIVER FUNDING IV, L.L.C.

## STATEMENT OF CASH FLOWS

### For the Period from Inception (August 2, 2001) to December 31, 2001
### (In thousands)

| | |
|---|---|
| Cash flows from operating activities | |
| Net income | $ 75,514 |
| Adjustments to reconcile net income to net cash from operating activities: | |
| Initial market gain on power agreements, net | (75,948) |
| Change in market value of power purchase agreements, net | 4,221 |
| Working capital changes: | |
| Accounts payable — affiliate | 1,651 |
| Accounts payable — Connecticut Light and Power | (5,438) |
| Net cash provided from operating activities | — |
| Net change in cash and cash equivalents | — |
| Cash and cash equivalents | |
| Beginning of period | — |
| End of period | $ — |
| Non-cash transactions | |
| Contribution of power purchase agreement from members | $ 17,526 |
| Liability to Connecticut Light and Power | 14,205 |

See accompanying notes.

## MOHAWK RIVER FUNDING IV, L.L.C.

## STATEMENT OF MEMBERS' CAPITAL

### For the Period from Inception (August 2, 2001) to December 31, 2001
### (In thousands)

| | ANR Venture Management Company | Mesquite Investors, L.L.C. (50%) | Total Members' Capital |
|---|---|---|---|
| Initial contribution on August 2, 2001 | $ — | $ 1 | $ 1 |
| Contribution receivable from member | — | (1) | (1) |
| Contribution of power purchase agreement from member | — | 17,526 | 17,526 |
| Net income | 37,757 | 37,757 | 75,514 |
| December 31, 2001 | $37,757 | $55,283 | $93,040 |

See accompanying notes.

**MOHAWK RIVER FUNDING IV, L.L.C.**

**NOTES TO THE FINANCIAL STATEMENTS**

## 1. Organization and Nature of Operations

We are a Delaware limited liability company (formerly known as Poquonock River Funding, L.L.C.) organized in August 2001, under the terms of a limited liability company agreement. We are jointly owned by ANR Venture Management Company, a wholly owned subsidiary of El Paso Corporation, and Mesquite Investors, L.L.C., an entity which is indirectly owned by Limestone Electron Trust and El Paso. Our sole business is to sell electric energy and provide electric capacity to The Connecticut Light and Power Company, a specially chartered Connecticut corporation and public service company, under an amended power purchase agreement that we entered into with Connecticut Light and Power.

On October 19, 2001, one of our affiliates, Capitol District Energy Center Cogeneration Association, a Connecticut joint venture, distributed its power purchase agreement with Connecticut Light and Power to its members, ANR Venture and Mesquite Investors. ANR Venture and Mesquite Investors immediately contributed their interest in the power purchase agreement, which had an aggregate book value of $17.5 million, to us. We amended the contributed power purchase agreement and began operating under the amended power purchase agreement on October 21, 2001. We do not have any employees and our operations are carried out by El Paso Chaparral Management, L.P., a subsidiary of El Paso Corporation, under a management agreement between El Paso Chaparral Management and Mesquite Investors (see Note 5). We purchase the electric capacity and electric energy necessary to meet our obligations under our amended power purchase agreement from El Paso Merchant Energy, L.P., a wholly owned indirect subsidiary of El Paso (see Note 4).

## 2. Limited Liability Company

As a limited liability company, our members are not personally obligated for our debt, obligations, or other liabilities simply because they are our members. These debts, obligations and other liabilities are solely ours.

## 3. Summary of Significant Accounting Policies

*Basis of Presentation*

Our financial statements are prepared on the accrual basis of accounting in accordance with accounting principles generally accepted in the United States.

*Use of Estimates*

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Actual results may differ from those estimates.

*Cash and Cash Equivalents*

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

*Allowance for Doubtful Accounts*

We review collectibility of our accounts receivable on a regular basis under the specific identification method. At December 31, 2001, no allowance for doubtful accounts was recorded.

*Income Taxes*

Since we are a limited liability company, income taxes accrue to our members. As a result, we have not reflected a provision for income taxes in our financial statements.

*Revenue Recognition*

We recognize revenue when we deliver electric energy and provide electric capacity to Connecticut Light and Power. Revenue is based on the quantity of electricity delivered and capacity provided at rates specified in our amended power purchase agreement.

*Accounting for Derivative Instruments*

We record all derivative instruments on our balance sheet at their fair value in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities.* Our amended power purchase agreement and mirror power purchase agreement qualify as derivative instruments under these standards. As a result, they are recorded at their fair value in our balance sheet. Changes in the fair value of these agreements are reported in our income statement as a change in the market value of power agreements. We estimate the fair value of these agreements based on an estimate of the cash receipts and payments under these agreements using anticipated future power prices compared to the contractual prices under these agreements, discounted at a risk-adjusted rate commensurate with the term of each contract and the credit risk of each counterparty. Our estimates of the timing of cash receipts and payments are based on the anticipated timing of power delivered under these agreements. These estimates also consider the minimum and maximum energy delivery requirements under those agreements. Estimates of the future prices of power are based on the forward pricing curve of the appropriate power delivery and receipt points, and this curve is derived from the actual prices observed in the market, price quotes from brokers and extrapolation models that rely on actively quoted prices and historical information.

As discussed above, our power purchase agreement was contributed to us by our members and recorded initially at our members' cost of $17.5 million. The cost represented Mesquite Investor's basis in the power purchase agreement as a result of the acquisition of its interest in Capitol District Energy Center from AE Fourteen, Inc., a subsidiary of Aetna Life Insurance Company. As consideration for amending our power purchase agreement, we agreed to pay Connecticut Light and Power $14.2 million. We also entered into the mirror power purchase agreement with El Paso Merchant. Since these agreements qualify as derivatives, our cost basis was adjusted to estimated fair value. We reflected the difference between the carrying value of these agreements, and their estimated market value as the initial market gain on power agreements of $75.9 million in our income statement. We included this amount as other income since the initial market gain was incidental to the operation and execution of our power purchase agreements. This initial gain is comprised of the initial value of our amended power purchase agreement of $77.8 million, less the initial market value of our mirror power purchase agreement of $1.9 million. Following this initial valuation, changes in the fair values of these power purchase agreements, which were $4.2 million through December 31, 2001, have been reflected as a change in market value of power agreements in operating expenses. These amounts are included in our operating income since changes in the value of our power agreements result primarily from the execution of our obligations under our power purchase agreements. See Note 4 for additional information on the amended power purchase and mirror power purchase agreements.

## 4. Commitments and Contingencies

*Amended Power Purchase Agreement*

The amended power purchase agreement with Connecticut Light and Power supercedes a pre-existing long-term power purchase agreement originally entered into between Connecticut Light and Power and

Capitol District Energy Center. The pre-existing long-term power purchase agreement provided for the purchase by Connecticut Light and Power of electric energy and electric capacity from Capitol District Energy Center. Through a series of transactions, the pre-existing power purchase agreement was distributed to our members who in turn contributed it to us. Upon the contribution of the power purchase agreement, we amended its terms with Connecticut Light and Power. Under this amended power purchase agreement, we are required to arrange for electric capacity to be made available to Connecticut Light and Power. Additionally, we will sell and deliver energy to Connecticut Light and Power at specified delivery points, up to 45,000 kilowatt hours (kWh) of energy during each hour of each on-peak period and up to 30,000 kWh of energy during each hour of each off-peak period. We shall not schedule and deliver more than 179,628 megawatt hours (MWh) of energy during the on-peak periods occurring within any calendar year or 128,353 MWh of energy during the off-peak periods occurring within any calendar year. For the period ended December 31, 2001, we recorded electricity sales to Connecticut Light and Power of $5.4 million as operating revenues.

During each on-peak period of each summer period and winter period during the delivery term, we are required to schedule and deliver enough energy during such period so that the period performance factor, as defined in the amended power purchase agreement, is greater than or equal to ninety-seven percent. If we fail to meet these minimum on-peak deliveries, we shall pay Connecticut Light and Power liquidated damages equal to the positive difference, if any, of (a) the sum of the Aggregate New England Power Pool (NEPOOL) Deficiency Cost, as defined in our amended power purchase agreement, for each hour during such period minus (b) the sum of the Aggregate Contract Deficiency Cost, as defined in our amended power purchase agreement, for each hour during such period.

If we fail to deliver all or part of the scheduled energy for reasons other than a force majeure event, we shall pay to Connecticut Light and Power liquidated damages equal to the product of (a) the number of kWh we scheduled but failed to deliver and (b) the positive difference, if any, of (i) the Final Hourly Clearing Price for Energy, as defined in our amended power purchase agreement, delivered at the delivery point with respect to each hour minus (ii) the Energy Charge, as defined in the amended power purchase agreement, with respect to such hour.

If we fail to provide all or part of the required electric capacity for reasons other than a force majeure event, we must pay to Connecticut Light and Power a liquidated damages payment equal to the product of (a) the amount of electric capacity we failed to provide in such month and (b) the positive difference, if any, of (i) the applicable New England Independent System Operator monthly electric capacity amount purchase Market Clearing Price minus (ii) the electric capacity charge paid by Connecticut Light and Power, as defined in the amended power purchase agreement.

As incentive to enter into the amended power purchase agreement, we agreed to pay Connecticut Light and Power $14.2 million, which amount is to be paid through credits against invoices for power sold to Connecticut Light and Power. The remaining liability at December 31, 2001 is $8.8 million.

*Mirror Power Purchase Agreement*

We have entered into a mirror power purchase agreement with El Paso Merchant in order to have El Paso Merchant deliver to us the energy and electric capacity that we are required to deliver to Connecticut Light and Power under the amended power purchase agreement.

Under the mirror power purchase agreement, El Paso Merchant must schedule and deliver the required energy that we are obligated to deliver under the amended power purchase agreement, and must make available to us electric capacity credits equal to the electric capacity requirements under the amended power purchase agreement. El Paso Merchant must schedule and deliver 179,628 MWh of energy during the on-peak period of each calendar year and 128,353 MWh of energy during the off-peak period of each calendar year. If El Paso Merchant fails to deliver all or part of the scheduled energy to us, for any reason other than a force majeure event, our payment to El Paso Merchant will be reduced by a credit calculated in the same manner as the credit to Connecticut Light and Power described in the amended power purchase agreement.

If El Paso Merchant fails in any month to provide all or part of the electric capacity, for any reason other than a force majeure event, our payment to El Paso Merchant will be reduced by a credit calculated in the same manner as the credit to Connecticut Light and Power as a direct result of our failure to provide energy and electric capacity under the amended power purchase agreement.

## 5. Related Party Transactions

*Mirror Power Purchase Agreement*

El Paso Merchant provides electric energy and capacity to us under the mirror power purchase agreement discussed above. Expenses under this agreement are based on market rates at the time the agreement was negotiated. Total purchases for the period ended December 31, 2001 were $1.7 million and have been reflected as electricity purchases from affiliates in our income statement. Amounts owed under the contract are reflected as an affiliate payable in our balance sheet.

*Administrative Services*

Our operations are carried out by El Paso Chaparral Management under a management agreement between El Paso Chaparral Management and Mesquite Investors. El Paso Chaparral Management is responsible for our functions that are normally considered part of the day-to-day administrative and management activities, including financial, accounting, budgeting, tax services, general legal and financial services, personnel administration, payroll services and cash management services. The expenses paid by Mesquite Investors, under this agreement, on our behalf, are immaterial and, as such, have not been allocated on our behalf.

## 6. Concentration of Credit Risks

Our accounts receivable potentially subject us to credit risk. Our trade receivables and revenues are solely from a single customer, Connecticut Light and Power, which purchases electric energy and electric capacity from us under a long-term power purchase agreement.

## 7. Fair Value of Financial Instruments

As of December 31, 2001, the carrying amounts of our financial instruments including cash, cash equivalents, and trade receivables and payables are representative of fair value because of their short-term maturity.

**GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP**

**FINANCIAL STATEMENTS**
**WITH INDEPENDENT AUDITORS' REPORT**
**December 31, 2001**

## INDEPENDENT AUDITORS' REPORT

The Partners and Management Committee
Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (Partnership) as of December 31, 2001 and 2000, and the related consolidated statements of income and partners' capital, and cash flows for each of the years in the three year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

/s/ KPMG LLP

Detroit, Michigan
January 9, 2002

**GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP**

**CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS' CAPITAL**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | (Thousands of Dollars) | | |
| Transportation Revenues | $ 276,872 | $ 282,636 | $283,287 |
| Operating Expenses | | | |
| Operation and Maintenance | 32,662 | 39,807 | 44,752 |
| Depreciation | 56,640 | 60,705 | 58,821 |
| Income Taxes Payable by Partners | 39,950 | 39,518 | 40,032 |
| Property and Other Taxes | 28,828 | 29,322 | 26,725 |
| | 158,080 | 169,352 | 170,330 |
| Operating Income | 118,792 | 113,284 | 112,957 |
| Other Income (Expense) | | | |
| Interest on Long Term Debt | (47,960) | (47,474) | (44,362) |
| Allowance for Funds Used During Construction | 464 | 769 | 1,837 |
| Other, Net | 2,511 | 5,935 | 2,012 |
| | (44,985) | (40,770) | (40,513) |
| Net Income | $ 73,807 | $ 72,514 | $ 72,444 |
| Partners' Capital | | | |
| Balance at Beginning of Year | $ 449,237 | $ 604,838 | $569,631 |
| Contributions by General Partners | 21,226 | 19,290 | 21,966 |
| Net Income | 73,807 | 72,514 | 72,444 |
| Current Income Taxes Payable by Partners Charged to Earnings | 23,378 | 24,548 | 28,461 |
| Distributions to Partners | (124,008) | (271,953) | (87,664) |
| Balance at End of Year | $ 443,640 | $ 449,237 | $604,838 |

The accompanying notes are an integral part of these statements.

## GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

## CONSOLIDATED BALANCE SHEETS

| | As of December 31, 2001 | As of December 31, 2000 |
|---|---|---|
| | (Thousands of Dollars) | |
| **ASSETS** | | |
| Current Assets | | |
| Cash and Temporary Cash Investments | $ 40,320 | $ 39,940 |
| Receivable from Limited Partner | 1,922 | — |
| Accounts Receivable | 29,145 | 35,311 |
| Materials and Supplies, at Average Cost | 10,035 | 10,618 |
| Regulatory Assets | 566 | 7,516 |
| Prepayments and Other | 4,403 | 3,436 |
| | 86,391 | 96,821 |
| Gas Utility Plant | | |
| Property, Plant and Equipment | 1,965,442 | 1,946,348 |
| Less Accumulated Depreciation | 772,832 | 729,136 |
| | 1,192,610 | 1,217,212 |
| | $1,279,001 | $1,314,033 |
| **LIABILITIES & PARTNERS' CAPITAL** | | |
| Current Liabilities | | |
| Current Maturities of Long Term Debt | $ 36,500 | $ 19,500 |
| Accounts Payable | 14,344 | 20,011 |
| Payable to Limited Partner | — | 1,526 |
| Property and Other Taxes | 27,895 | 29,340 |
| Accrued Interest and Other | 13,421 | 16,293 |
| | 92,160 | 86,670 |
| Long Term Debt | 532,250 | 575,750 |
| Other Liabilities | | |
| Amounts Equivalent to Deferred Income Taxes | 206,057 | 193,139 |
| Regulatory Liabilities | 3,870 | 5,287 |
| Other | 1,024 | 3,950 |
| | 210,951 | 202,376 |
| Partners' Capital | 443,640 | 449,237 |
| | $1,279,001 | $1,314,033 |

The accompanying notes are an integral part of these statements.

## GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2001 | 2000 | 1999 |
| | (Thousands of dollars) | | |
| Cash Flow Increase (Decrease) from: | | | |
| Operating Activities | | | |
| Net Income | $ 73,807 | $ 72,514 | $ 72,444 |
| Adjustments to Reconcile Net Income to Operating Cash Flows: | | | |
| Depreciation | 56,640 | 60,705 | 58,821 |
| Amounts Equivalent to Deferred Income Taxes | 12,918 | 15,411 | 12,286 |
| Regulatory Assets | 6,950 | 1,209 | (1,333) |
| Regulatory Liabilities | (1,417) | (1,452) | (1,424) |
| Allowance for Funds Used During Construction | (464) | (769) | (1,837) |
| Changes in Current Assets and Liabilities: | | | |
| Accounts Receivable | 6,166 | (1,289) | (6,774) |
| Accounts Payable | (5,667) | (1,205) | 662 |
| Property and Other Taxes | (1,445) | (1,689) | (1,943) |
| Other | (9,630) | (52) | 11,127 |
| | 137,858 | 143,383 | 142,029 |
| Investment in Utility Plant | (31,574) | (33,372) | (48,909) |
| Financing Activities | | | |
| Issuance of Long Term Debt | — | 100,000 | — |
| Repayment of Long Term Debt | (26,500) | (17,800) | (39,700) |
| Contributions by Partners | 21,226 | 19,290 | 21,966 |
| Current Income Taxes Payable by Partners Charged to Earnings | 23,378 | 24,548 | 28,461 |
| Distributions to Partners | (124,008) | (271,953) | (87,664) |
| | (105,904) | (145,915) | (76,937) |
| Change in Cash and Cash Equivalents | 380 | (35,904) | 16,183 |
| Cash and Cash Equivalents: | | | |
| Beginning of Year | 39,940 | 75,844 | 59,661 |
| End of Year | $ 40,320 | $ 39,940 | $ 75,844 |
| Supplemental Disclosure of Cash Flow Information | | | |
| Cash Paid During the Year for Interest (Net of Amounts Capitalized of $206, $249 and $705, Respectively) | $ 48,197 | $ 44,199 | $ 44,281 |

The accompanying notes are an integral part of these statements.

## GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Organization and Management

Great Lakes Gas Transmission Limited Partnership (Partnership) is a Delaware limited partnership which owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to customers in the midwestern and northeastern United States and eastern Canada. Partnership ownership percentages are recalculated each year to reflect distributions and contributions. The partners, their parent companies, and partnership ownership percentages are as follows:

| | Ownership % | |
|---|---|---|
| **Partner (Parent Company)** | **2001** | **2000** |
| General Partners: | | |
| Coastal Great Lakes, Inc. (El Paso Corporation) | 45.40 | 39.29 |
| TransCanada GL, Inc. (TransCanada PipeLines Ltd.) | 45.40 | 39.29 |
| Limited Partner: | | |
| Great Lakes Gas Transmission Company (TransCanada PipeLines Ltd. and El Paso Corporation) | 9.20 | 21.42 |

Coastal Great Lakes, Inc. was formally owned by The Coastal Corporation (Coastal), which merged into a subsidiary of El Paso Corporation (El Paso) on January 29, 2001.

The day-to-day operation of Partnership activities is the responsibility of Great Lakes Gas Transmission Company (Company), which is reimbursed for its employee salaries, benefits and other expenses, pursuant to the Partnership's Operating Agreement with the Company.

### 2. Summary of Significant Accounting Policies

*Principles of Consolidation and Basis of Presentation*

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation owns and operates a transport aircraft used principally for pipeline operations. Intercompany amounts have been eliminated.

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents.

The Partnership recognizes revenues from natural gas transportation in the period the service is provided.

Management of the Partnership has made estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

*Regulation*

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership's accounting policies reflect the effects of the ratemaking process in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting Principles for the Effects of Certain Types of Regulation.* Regulatory assets and liabilities have been established and represent probable future revenue or expense which will be recovered from or refunded to customers. The regulatory assets and liabilities are primarily related to prior changes in federal income tax rates.

*Gas Utility Plant and Depreciation*

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The cost of plant retired is charged to accumulated depreciation. Depreciation of gas utility plant is computed using the straight-line method. The Partnership's principal operating assets were depreciated at an annual rate of 2.75% for 2001 and 3.00% for both 2000 and 1999.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rate used in 2001, 2000 and 1999 were 10.36%, 10.95% and 10.84%, respectively.

*Income Taxes*

The Partnership's tariff includes an allowance for income taxes which the FERC requires the Partnership to record as if it were a corporation. The provisions for current and deferred income tax expense are recorded without regard to whether each partner can utilize its share of the Partnership's tax deductions. Income taxes are deducted in the Consolidated Statements of Income and the current portion of income taxes is returned to partners' capital. Recorded current income taxes are distributed to partners based on their ownership percentages.

Amounts equivalent to deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases at currently enacted income tax rates.

### 3. Affiliated Company Transactions

Affiliated company amounts included in the Partnership's consolidated financial statements, not otherwise disclosed, are as follows:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In Thousands) | |
| Accounts receivable | $ 15,936 | $ 17,447 | $ 18,540 |
| Transportation revenues: | | | |
| TransCanada PipeLines Ltd. and affiliates | 176,818 | 185,912 | 185,566 |
| El Paso Corporation and affiliates | 25,716 | — | — |
| The Coastal Corporation and affiliates | — | 28,981 | 30,269 |
| Interest income | — | 3,664 | 446 |

The Partnership reimburses the Company for salaries, benefits and other incurred expenses. Benefits include pension, thrift plan, and other postretirement benefits. Operating expenses charged by the Company in 2001, 2000 and 1999 were $13,671,000, $21,147,000 and $25,348,000, respectively.

The Company accounts for pension benefits on an accrual basis. Effective with the merger of The Coastal Corporation and El Paso Corporation in 2001, the former pension plan was merged into the El Paso cash balance pension plan. The annual net pension credit was $8,500,000, $5,000,000 and $4,300,000, in 2001, 2000 and 1999, respectively.

In 1999, the Company amended its existing pension plan to offer a voluntary Early Retirement Incentive Program (ERIP) to employees who were at least 55 years of age with at least 5 years of service. Cost related to the ERIP of approximately $4,600,000 were recorded in 1999.

The Company makes contributions for eligible employees of the Company to a voluntary defined contribution plan sponsored by one of the parent companies. The Company's contributions, which are based on matching employee contributions, amounted to $832,000, $980,000 and $1,022,000 in 2001, 2000 and 1999, respectively.

The Company accounts for other post-retirement benefits on an accrual basis. The annual expense was $215,000 for 2001 and $556,000 for both 2000 and 1999. In addition, curtailment costs of approximately $695,000 were recorded in 2001 related to the conversion to the El Paso Corporation benefit plans which changed future benefits for eligible employees.

## 4. Regulatory Matters

On October 26, 2000, the FERC issued an order approving the Partnership's filing of a Joint Stipulation and Agreement Regarding Rates which was subsequently reaffirmed on February 8, 2001, by its order denying rehearing. The settlement continues the Partnership's existing rates until October 31, 2005, and provides a decrease in the Partnership's depreciation rate from 3.00% to 2.75% for transmission plant effective January 1, 2001.

## 5. Debt

| | 2001 | 2000 |
|---|---|---|
| | (In Thousands) | |
| Senior Notes, unsecured, interest due semiannually, principal due as follows: | | |
| 9.81% series, due 2002 to 2003 | $ 12,750 | $ 25,250 |
| 9.35% series, due 2002 to 2005 | 56,000 | 70,000 |
| 8.74% series, due 2002 to 2011 | 100,000 | 100,000 |
| 9.09% series, due 2012 to 2021 | 100,000 | 100,000 |
| 6.73% series, due 2009 to 2018 | 90,000 | 90,000 |
| 6.95% series, due 2019 to 2028 | 110,000 | 110,000 |
| 8.08% series, due 2021 to 2030 | 100,000 | 100,000 |
| | 568,750 | 595,250 |
| Less current maturities | 36,500 | 19,500 |
| Total long term debt less current maturities | $532,250 | $575,750 |

The aggregate estimated fair value of long term debt was $607,000,000 and $615,000,000 for 2001 and 2000, respectively. The fair value is determined using discounted cash flows based on the Partnership's estimated current interest rates for similar debt.

The aggregate annual required repayments of Senior Notes for each of the five years 2002 through 2006 are $36,500,000, $24,250,000, $24,000,000, $24,000,000 and $17,000,000, respectively.

Under the most restrictive covenants in the Senior Note Agreements, approximately $306,000,000 of partners' capital is restricted as to distributions as of December 31, 2001.

## 6. Income Taxes Payable by Partners

Income tax expense for the years ended December 31, 2001, 2000 and 1999 consists of:

| | 2001 | 2000 | 1999 |
|---|---|---|---|
| | | (In Thousands) | |
| Current | | | |
| Federal | $22,366 | $23,496 | $26,893 |
| State and local | 1,012 | 1,052 | 1,568 |
| | 23,378 | 24,548 | 28,461 |
| Deferred | | | |
| Federal | 15,835 | 14,306 | 10,884 |
| State and local | 737 | 664 | 687 |
| | 16,572 | 14,970 | 11,571 |
| | $39,950 | $39,518 | $40,032 |

Income tax expense differs from the statutory rate of 35% due to the amortization of excess deferred taxes along with the effects of state and local taxes. The Partnership is required to amortize excess deferred taxes which had previously been accumulated at tax rates in excess of current statutory rates. Such amortization reduced income tax expense by $900,000 for 2001, 2000 and 1999. As of December 31, 2001, the remaining unamortized balance is $2,375,000.

Amounts equivalent to deferred income taxes include the effects of temporary differences associated with excess tax depreciation on utility plant and state taxes. As of December 31, 2001 and 2000, no valuation allowance is required. The deferred tax assets and deferred tax liabilities as of December 31, 2001 and 2000 are as follows:

| | 2001 | 2000 |
|---|---|---|
| | (In Thousands) | |
| Deferred tax assets | $ 4,868 | $ 3,951 |
| Deferred tax liabilities | (210,925) | (197,090) |
| Net deferred tax liability | $(206,057) | $(193,139) |

## 7. Contingencies

Great Lakes has pending refund claims related to use taxes paid to the State of Minnesota for years 1994 to 2000. No amounts have been recorded in the financial statements related to the ultimate outcome of this contingency.

## EL PASO CGP COMPANY

## EXHIBIT LIST

**December 31, 2001**

Each exhibit identified below is filed as a part of this report. 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. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

| Exhibit No. | Description |
|---|---|
| 3.A | — Amended and Restated Certificate of Incorporation dated January 31, 2001 (Exhibit 3.A to our 2000 Form 10-K). |
| 3.B | — By-Laws dated January 29, 2001 (Exhibit 3.B to 2000 Form 10-K). |
| 10.A | — $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.G to our 2000 Form 10-K). |
| 10.B | — Joinder Agreement dated February 5, 2001 made by El Paso CGP Company to the $1,000,000,000 3-Year Revolving Credit and CAF Advance Facility Agreement 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, as Administrative Agent and CAF Advance Agent, Citibank, N.A. and ABN Amro, N.V. as Co-Documentation Agents, and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.H to our 2000 Form 10-K). |
| *18 | — Letter regarding Change in Accounting Principle |
| *99.1 | — Report of Independent Accountants, PricewaterhouseCoopers LLP |
| *99.2 | — Independent Auditors' Report, Deloitte & Touche LLP |

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

None.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso CGP Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 28th day of March 2002.

EL PASO CGP COMPANY
(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 CGP Company and in the capacities and on the dates indicated:

| Name | Title | Date |
|---|---|---|
| By: /s/ WILLIAM A. WISE (William A. Wise) | Chairman of the Board, President and Chief Executive Officer and Director (Principal Executive Officer) | March 28, 2002 |
| By: /s/ H. BRENT AUSTIN (H. Brent Austin) | Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer) | March 28, 2002 |
| By: /s/ JEFFREY I. BEASON (Jeffrey I. Beason) | Senior Vice President and Controller (Principal Accounting Officer) | March 28, 2002 |