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

# Form 10-K/A
(Amendment No. 1)

(Mark One)

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

For the fiscal year ended December 31, 2004

OR

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

For the transition period from to .

Commission File Number 1-14365

# El Paso Corporation
(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| **Delaware** | **76-0568816** |
| (State or Other Jurisdiction of Incorporation or Organization) | (I.R.S. Employer Identification No.) |
| **El Paso Building 1001 Louisiana Street Houston, Texas** | **77002** |
| (Address of Principal Executive Offices) | (Zip Code) |

**Telephone Number: (713) 420-2600**
**Internet Website: www.elpaso.com**

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

| Title of Each Class | Name of Each Exchange on which Registered |
|---|---|
| Common Stock, par value $3 per share | New York Stock Exchange |

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☑ No ☐.

**State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant.**

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 30, 2004 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $5,066,348,130.

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

Common Stock, par value $3 per share. Shares outstanding on March 23, 2005: 642,934,481

**Documents Incorporated by Reference**

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive proxy statement for the 2005 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2005.

## EL PASO CORPORATION

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

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

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 a pressure of 14.73 pounds per square inch.

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

## EXPLANATORY NOTE

This Form 10-K/A (Amendment No. 1) is being filed to revise the manner in which we reported certain of our income taxes associated with our discontinued Canadian exploration and production operations for the year ended December 31, 2003. During the fourth quarter of 2003, we appropriately recorded a deferred tax benefit related to our Canadian exploration and production operations. This amount was properly included as part of our continuing operations in our 2003 Annual Report on Form 10-K. During 2004, we decided to exit our Canadian exploration and production operations and classified them as discontinued operations. Our 2004 Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2005 reflected these operations as discontinued for all periods. However, we incorrectly included approximately $82 million of deferred tax benefits in continuing operations in the fourth quarter of 2003 that should have been reflected in discontinued operations. As a result, we were required to restate our 2003 financial statements to reclassify this amount from continuing operations to discontinued operations. This restatement did not affect our reported net loss, balance sheet amounts or cash flows as of or for the year ended December 31, 2003.

The restatement affects language and tabular amounts in Item 6. Selected Financial Data; Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations; Item 8. Financial Statements and Supplementary Data; and Item 9A. Controls and Procedures.

PART I

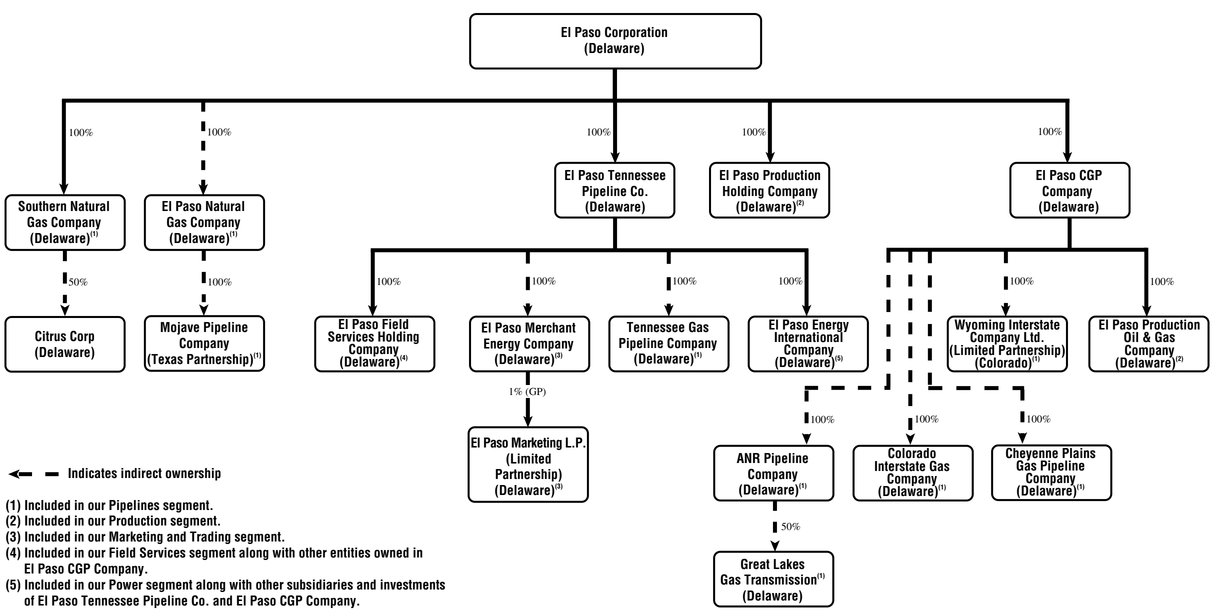
## ITEM 1. BUSINESS

We are an energy company originally founded in 1928 in El Paso, Texas. For many years, we served as a regional natural gas pipeline company conducting business mainly in the western United States. From 1996 through 2001, we expanded to become an international energy company through a number of mergers, acquisitions and internal growth initiatives. By 2001, our operations expanded to include natural gas production, power generation, petroleum businesses, trading operations and other new ventures and businesses, in addition to our traditional natural gas pipeline businesses. During this period, our total assets grew from approximately $2.5 billion at December 31, 1995 to over $44 billion following the completion of The Coastal Corporation merger in January 2001. During this same time period, we incurred substantial amounts of debt and other obligations.

In late 2001 and in 2002, our industry and business were adversely impacted by a number of significant events, including (i) the bankruptcy of a number of energy sector participants, (ii) the general decline in the energy trading industry, (iii) performance in some areas of our business that did not meet our expectations, (iv) credit rating downgrades of us and other industry participants and (v) regulatory and political pressures arising out of the western energy crisis of 2000 and 2001.

These events adversely affected our operating results, our financial condition and our liquidity during 2002 and 2003. During this two year period, we refocused on our natural gas assets and divested or otherwise sold our interests in a significant number of assets, generating proceeds in excess of $6 billion. As a result of those sales activities and the performance of our businesses during this time period, we also experienced significant losses.

In late 2003 and early 2004, we appointed a new chief executive officer and several new members of the executive management team. Following a period of assessment, we announced that our long-term business strategy would principally focus on our core pipeline and production businesses. Our businesses are owned through a complex legal structure of companies that reflect the acquisitions and growth in our business from 1996 to 2001. As part of our long range strategy, we are actively working to reduce the complexity of our corporate structure, which is shown below in a condensed format, as of December 31, 2004.



## Business Segments

For the year ended December 31, 2004, we had both regulated and non-regulated operations conducted through five business segments — Pipelines, Production, Marketing and Trading, Power and Field Services. Through these segments, we provided the following energy related services:

| | |
|---|---|
| *Regulated Operations* | |
| Pipelines | Our interstate natural gas pipeline system is the largest in the U.S., and owns or has interests in approximately 56,000 miles of pipeline and approximately 420 Bcf of storage capacity. We provide customers with interstate natural gas transmission and storage services from a diverse group of supply regions to major markets around the country, serving many of the largest market areas. |
| *Non-regulated Operations* | |
| Production | Our production business holds interests in approximately 3.6 million net developed and undeveloped acres and had approximately 2.2 Tcfe of proved natural gas and oil reserves worldwide at the end of 2004. During 2004, our production averaged approximately 814 MMcfe/d. |
| Marketing and Trading | Our marketing and trading business markets our natural gas and oil production and manages our historical energy trading portfolio. During 2004, we continued to actively liquidate this historical trading portfolio. |
| Power | Our power business changed significantly during 2003 and 2004 with the sale of a substantial portion of our domestic power assets. As of December 31, 2004, we continued to own or manage approximately 10,400 MW of gross generating capacity in 16 countries. Our plants serve customers under long-term and market-based contracts or sell to the open market in spot market transactions. We have completed the sale of substantially all of our domestic contracted power assets and are either pursuing or evaluating the sale of many of our international assets. |
| Field Services | Our midstream or field services business provides processing and gathering services, primarily in south Louisiana. Through December 2004, we also owned a 9.9 percent interest in the general partner of Enterprise Products Partners L.P. (Enterprise), a large publicly traded master limited partnership, as well as a 3.7 percent limited partner interest in Enterprise. In January 2005, we sold all of our ownership interests in Enterprise and its general partner. We currently expect to sell many of our remaining Field Services assets. |

During 2004, we also had discontinued operations related to a historical petroleum markets business and international natural gas and oil production operations, primarily in Canada.

Under our long-term business strategy, we will continue to concentrate on our core pipeline and production businesses and activities that support those businesses while divesting or otherwise disposing of our ownership in non-core assets and operations. Our long-term strategy will focus on:

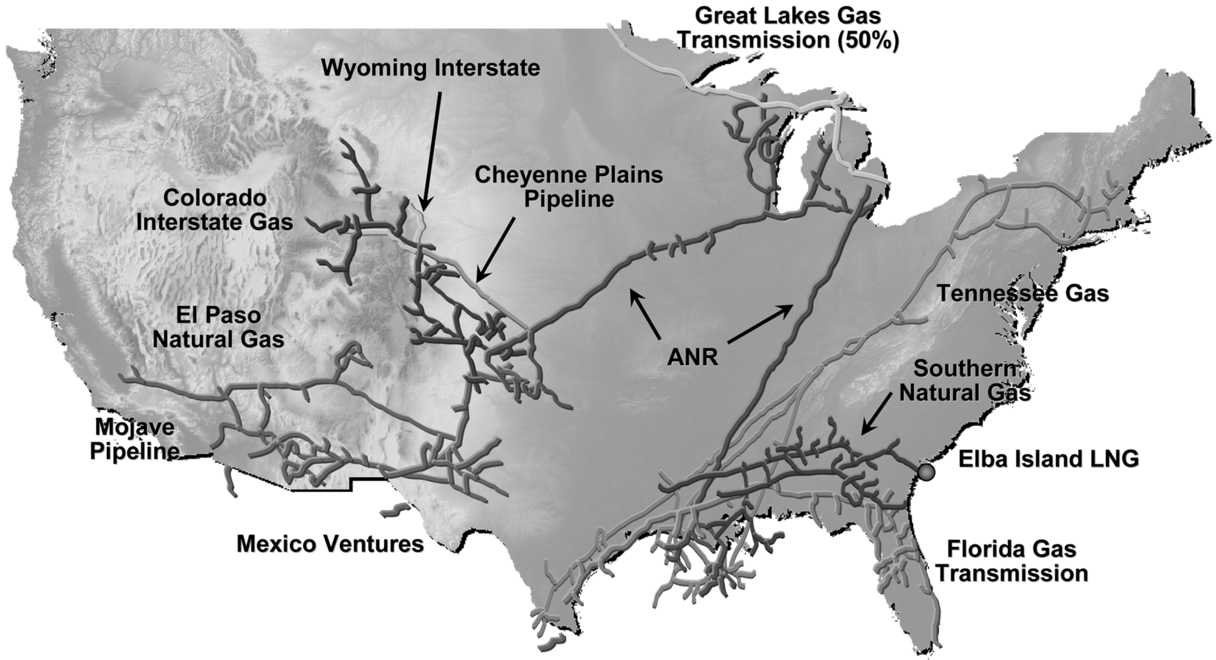
| Business | Objective and Strategy |
|---|---|
| Pipelines | Protecting and enhancing asset value through successful recontracting, continuous efficiency improvements through cost management, and prudent capital spending in the U.S. and Mexico. |
| Production | Growing our production business in a way that creates shareholder value through disciplined capital allocation, cost leadership and superior portfolio management. |
| Marketing and Trading | Marketing and physical trading of our natural gas and oil production. |
| Power | Managing our remaining power generation assets to maximize value. |
| Field Services | Optimizing our remaining gathering and processing assets. |

Below is a discussion of each of our business segments. Our business segments provide a variety of energy products and services. We managed each segment separately and each segment requires different technology and marketing strategies. For additional discussion of our business segments, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and identifiable assets, see Part II, Item 8, Financial Statements and Supplementary Data, Note 21, which is incorporated herein by reference.

**Regulated Business — Pipelines Segment**

Our Pipelines segment provides natural gas transmission, storage, liquefied natural gas (LNG) terminalling and related services. We own or have interests in approximately 56,000 miles of interstate natural gas pipelines in the United States that connect the nation's principal natural gas supply regions to the six largest consuming regions in the United States: the Gulf Coast, California, the Northeast, the Midwest, the Southwest and the Southeast. These pipelines represent the nation's largest integrated coast-to-coast mainline natural gas transmission system. Our pipeline operations also include access to systems in Canada and assets in Mexico. We also own or have interests in approximately 420 Bcf of storage capacity used to provide a variety of flexible services to our customers and an LNG terminal at Elba Island, Georgia.

Our Pipelines segment conducts its business activities primarily through (i) eight wholly owned and four partially owned interstate transmission systems, (ii) five underground natural gas storage entities and (iii) an entity that owns the Elba Island LNG terminalling facility.




*Wholly Owned Interstate Transmission Systems*

| Transmission System | Supply and Market Region | As of December 31, 2004 Miles of Pipeline | Design Capacity | Storage Capacity | Average Throughput[1] 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|---|
| | | | (MMcf/d) | (Bcf) | | (BBtu/d) | |
| Tennessee Gas Pipeline (TGP) | Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston. | 14,200 | 6,876 | 90 | 4,469 | 4,710 | 4,596 |
| ANR Pipeline (ANR) | Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee. | 10,500 | 6,620 | 192 | 4,067 | 4,232 | 4,130 |
| El Paso Natural Gas (EPNG) | Extends from the San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico. | 11,000 | 5,650[2] | — | 4,074 | 3,874 | 3,799 |
| Southern Natural Gas (SNG) | Extends from Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. | 8,000 | 3,437 | 60 | 2,163 | 2,101 | 2,151 |

| Transmission System | Supply and Market Region | As of December 31, 2004 Miles of Pipeline | Design Capacity | Storage Capacity | Average Throughput[1] 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|---|
| | | | (MMcf/d) | (Bcf) | | (BBtu/d) | |
| 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 multiple interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest. | 4,000 | 3,000 | 29 | 1,744 | 1,685 | 1,687 |
| Wyoming Interstate (WIC) | Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming. | 600 | 1,997 | — | 1,201 | 1,213 | 1,194 |
| Mojave Pipeline (MPC) | Connects with the EPNG and Transwestern transmission systems at Topock, Arizona, and the Kern River Gas Transmission Company transmission system in California, and extends to customers in the vicinity of Bakersfield, California. | 400 | 400 | — | 161 | 192 | 266 |
| Cheyenne Plains Gas Pipeline (CPG) | Extends from the Cheyenne hub in Colorado to various pipeline interconnects near Greensburg, Kansas. | 400 | 396[3] | — | 89 | — | — |

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity reflects winter-sustainable west-flow capacity and 800 MMcf/d of east-end delivery capacity.

(3) This capacity was placed in service on December 1, 2004. Compression was added and placed in service on January 31, 2005, which increased the design capacity to 576 MMcf/d.

We also have several pipeline expansion projects underway as of December 31, 2004 that have been approved by the Federal Energy Regulatory Commission (FERC), the more significant of which are presented below:

| Transmission System | Project | Capacity | Description | Anticipated Completion Date |
|---|---|---|---|---|
| | | (MMcf/d) | | |
| ANR | EastLeg Wisconsin expansion | 142 | To replace 4.7 miles of an existing 14-inch natural gas pipeline with a 30-inch line in Washington County, add 3.5 miles of 8-inch looping[1] on the Denmark Lateral in Brown County, and modify ANR's existing Mountain Compressor Station in Oconto County, Wisconsin. | November 2005 |
| | NorthLeg Wisconsin expansion | 110 | To add 6,000 horsepower of electric powered compression at ANR's Weyauwega Compressor station in Waupaca County, Wisconsin. | November 2005 |
| CPG | Cheyenne Plains expansion | 179 | To add approximately 10,300 horsepower of compression and an additional treatment facility to the Cheyenne Plains project. | December 2005 |

*Partially Owned Interstate Transmission Systems*

| Transmission System[2] | Supply and Market Region | As of December 31, 2004 | | | Average Throughput[3] | | |
|---|---|---|---|---|---|---|---|
| | | Ownership Interest | Miles of Pipeline[3] | Design Capacity[3] | 2004 | 2003 | 2002 |
| | | (Percent) | | (MMcf/d) | (BBtu/d) | | |
| Florida Gas Transmission[4] | Extends from south Texas to south Florida. | 50 | 4,870 | 2,082 | 2,014 | 1,963 | 2,004 |
| Great Lakes Gas Transmission | Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan. | 50 | 2,115 | 2,895 | 2,200 | 2,366 | 2,378 |
| Samalayuca Pipeline and Gloria a Dios Compression Station | Extends from U.S./Mexico border to the State of Chihuahua, Mexico. | 50 | 23 | 460 | 433 | 409 | 434 |
| San Fernando Pipeline | Pipeline running from Pemex Compression Station 19 to Pemex metering station in San Fernando, Mexico in the State of Tamaulipas. | 50 | 71 | 1,000 | 951 | 130 | — |

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

(2) These systems are accounted for as equity investments.

(3) Miles, volumes and average throughput represent the systems' totals and are not adjusted for our ownership interest.

(4) We have a 50 percent equity interest in Citrus Corporation, which owns this system.

We also have a 50 percent interest in Wyco Development, L.L.C. Wyco owns the Front Range Pipeline, a state-regulated gas pipeline extending from the Cheyenne Hub to Public Service Company of Colorado's (PSCo) Fort St. Vrain electric generation plant, and compression facilities on WIC's Medicine Bow Lateral. These facilities are leased to PSCo and WIC, respectively, under long-term leases.

*Underground Natural Gas Storage Entities*

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

| Storage Entity | As of December 31, 2004 | | Location |
|---|---|---|---|
| | Ownership Interest | Storage Capacity[1] | |
| | (Percent) | (Bcf) | |
| Bear Creek Storage | 100 | 58 | Louisiana |
| ANR Storage | 100 | 56 | Michigan |
| Blue Lake Gas Storage | 75 | 47 | Michigan |
| Eaton Rapids Gas Storage[2] | 50 | 13 | Michigan |
| Young Gas Storage[2] | 48 | 6 | Colorado |

(1) Includes a total of 133 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

(2) These systems were accounted for as equity investments as of December 31, 2004.

*LNG Facility*

In addition to our pipeline systems and storage facilities, we own an LNG receiving terminal located on Elba Island, near Savannah, Georgia. The facility is capable of achieving a peak sendout of 675 MMcf/d and a base load sendout of 446 MMcf/d. The terminal was placed in service and began receiving deliveries in December 2001. The current capacity at the terminal is contracted with a subsidiary of British Gas, BG LNG Services, LLC. In 2003, the FERC approved our plan to expand the peak sendout capacity of the Elba Island facility by 540 MMcf/d and the base load sendout by 360 MMcf/d (for a total peak sendout capacity once completed of 1,215 MMcf/d and a base load sendout of 806 MMcf/d). The expansion is estimated to cost approximately $157 million and has a planned in-service date of February 2006.

*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 of our pipeline systems and storage facilities operates under FERC-approved tariffs that establish rates, terms and conditions for services to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage, terminalling and related services;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital. Our revenues from transportation, storage, LNG terminalling and related services (transportation services revenues) consist of reservation revenues and usage revenues. Reservation revenues are from customers (referred to as firm customers) whose contracts (which are for varying terms) reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) who pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn. In 2004, approximately 84 percent of our transportation services revenues were attributable to reservation charges paid by firm customers. The remaining 16 percent of our transportation services revenues are variable. Due to our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the creditworthiness of our customers. We also experience volatility in our financial results when the amount of gas utilized in our operations differs from the amounts we receive for that purpose.

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations. Our systems have ongoing programs designed to keep our facilities in compliance with these safety and environmental requirements, and we believe that our systems are in material compliance with the applicable requirements.

*Markets and Competition*

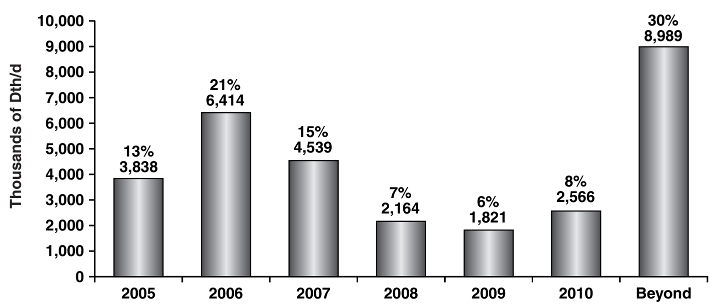
We provide natural gas services to a variety of customers including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear and hydroelectric power for power generation and fuel oil for heating.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing the delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. These LNG delivery systems also may compete with our pipelines for transportation of gas into market areas we serve.

Electric power generation is the fastest growing demand sector of the natural gas market. The growth and development of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. The increase in natural gas prices, driven in part by increased demand from the power sector, has diminished the demand for gas in the industrial sector. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their creditworthiness.

Our existing contracts mature at various times and in varying amounts of throughput capacity. As our pipeline contracts expire, our ability to extend our existing contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times and in certain regions, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. The table below shows the contracted capacity that expires by year over the next six years and thereafter.

**Contract Expirations**



The following table details the markets we serve and the competition faced by each of our wholly owned pipeline systems as of December 31, 2004:

| Transmission System | Customer Information | Contract Information | Competition |
|---|---|---|---|
| TGP | Approximately 432 firm and interruptible customers<br><br>Major Customers:<br>None of which individually represents more than 10 percent of revenues | Approximately 464 firm contracts<br>Weighted average remaining contract term of approximately five years. | TGP faces strong competition in the Northeast, Appalachian, Midwest and Southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and from the Canadian border.<br><br>In the offshore areas of the Gulf of Mexico, factors such as the distance of the supply field from the pipeline, relative basis pricing of the pipeline receipt options, costs of intermediate gathering or required processing of the gas all influence determinations of whether gas is ultimately attached to our system. |
| ANR | Approximately 259 firm and interruptible customers<br><br>Major Customer:<br>We Energies<br>(909 BBtu/d) | Approximately 570 firm contracts<br>Weighted average remaining contract term of approximately three years.<br><br>Contract terms expire in 2005-2010. | In the Midwest, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast, ANR competes with other interstate pipelines serving electric generation and local distribution companies. ANR also competes directly with other interstate pipelines, including Guardian Pipeline, for markets in Wisconsin. We Energies owns an interest in Guardian, which is currently serving a portion of its firm transportation requirements.<br><br>ANR also competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR's principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports. |

| Transmission System | Customer Information | Contract Information | Competition |
|---|---|---|---|
| EPNG | Approximately 155 firm and interruptible customers | Approximately 213 firm contracts<br>Weighted average remaining contract term of approximately five years[(1)(2)]. | EPNG faces competition in the West and Southwest from other existing pipelines, storage facilities, as well as alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil. |
| | Major Customer:<br>Southern California Gas Company[(2)] | | |
| | (475 BBtu/d) | Contract terms expire in 2006. | |
| | (82 BBtu/d) | Contract terms expire in 2005 and 2007. | |
| | (768 BBtu/d) | Contract terms expire in 2009-2011. | |

(1) Approximately 1,564 MMcf/d currently under contract is subject to early termination in August 2006 provided customers give timely notice of an intent to terminate. If all of these rights were exercised, the weighted average remaining contract term would decrease to approximately three years.

(2) Reflects the impact of an agreement we entered into, subject to FERC approval, to extend 750 MMCf/d of SoCal's current capacity, effective September 1, 2006, for terms of three to five years.

| Transmission System | Customer Information | Contract Information | Competition |
|---|---|---|---|
| SNG | Approximately 230 firm and interruptible customers | Approximately 203 firm contracts<br>Weighted average remaining contract term of approximately five years. | Competition is strong in a number of SNG's key markets. SNG's four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of many of its other customers. |
| | Major Customers:<br>Atlanta Gas Light Company | | |
| | (972 BBtu/d) | Contract terms expire in 2005-2007. | |
| | Southern Company Services | | |
| | (418 BBtu/d) | Contract terms expire in 2010-2018. | |
| | Alabama Gas Corporation | | |
| | (415 BBtu/d) | Contract terms expire in 2006-2013. | |
| | Scana Corporation | | |
| | (346 BBtu/d) | Contract terms expire in 2005-2019. | |

| Transmission System | Customer Information | Contract Information | Competition |
|---|---|---|---|
| CIG | Approximately 112 firm and interruptible customers<br><br>Major Customers:<br>Public Service Company of Colorado<br>(970 BBtu/d)<br>(261 BBtu/d)<br>(187 BBtu/d) | Approximately 191 firm contracts<br>Weighted average remaining contract term of approximately five years.<br><br>Contract term expires in 2007.<br>Contract term expires in 2009-2014.<br>Contract term expires in 2006. | CIG serves two major markets. Its "on-system" market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its "off-system" market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. Competition for its on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for its off-system market consists of other interstate pipelines that are directly connected to its supply sources. |
| WIC | Approximately 49 firm and interruptible customers<br><br>Major Customers:<br>Williams Power Company<br>(303 BBtu/d)<br>Colorado Interstate Gas Company<br>(247 BBtu/d)<br>Western Gas Resources<br>(235 BBtu/d)<br>Cantera Gas Company<br>(226 BBtu/d) | Approximately 47 firm contracts<br>Weighted average remaining contract term of approximately six years.<br><br>Contract terms expire in 2008-2013.<br>Contract terms expire in 2005-2016.<br>Contract terms expire in 2007-2013.<br>Contract terms expire in 2012-2013. | WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC's one Bcf/d Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply and can readily be expanded as supply increases. Currently, there are two other interstate pipelines that transport limited volumes out of this basin. |
| MPC | Approximately 14 firm and interruptible customers<br><br>Major Customers:<br>Texaco Natural Gas Inc.<br>(185 BBtu/d)<br>Burlington Resources Trading Inc.<br>(76 BBtu/d)<br>Los Angeles Department of Water and Power<br>(50 BBtu/d) | Approximately nine firm contracts<br>Weighted average remaining contract term of approximately two years.<br><br>Contract term expires in 2007.<br>Contract term expires in 2007.<br>Contract term expires in 2007. | MPC faces competition from existing pipelines, a newly proposed pipeline, LNG projects and alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil. |

| Transmission System | Customer Information | Contract Information | Competition |
|---|---|---|---|
| CPG | Approximately 15 firm and interruptible customers. | Approximately 14 firm contracts Weighted average remaining contract term of approximately 10 years. | Cheyenne Plains competes directly with other interstate pipelines serving the Mid-continent region. Indirectly, Cheyenne Plains competes with other interstate pipelines that transport Rocky Mountain gas to other markets. |
| | Major Customers: | | |
| | Oneok Energy Services Company L.P. (195 BBtu/d) | Contract term expires in 2015. | |
| | Anadarko Energy Service Company (100 BBtu/d) | Contract term expires in 2015. | |
| | Kerr McGee (83 BBtu/d) | Contract term expires in 2015. | |

**Non-regulated Business — 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 the United States and Brazil. In the United States, as of December 31, 2004, we controlled over 3 million net acres of leasehold acreage through our operations in 20 states, including Louisiana, New Mexico, Texas, Oklahoma, Alabama and Utah, and through our offshore operations in federal and state waters in the Gulf of Mexico. During 2004, daily equivalent natural gas production averaged approximately 814 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2004, were approximately 2.2 Tcfe.

As part of our long-term business strategy we will focus on developing production opportunities around our asset base in the United States and Brazil. Our operations are divided into the following areas:

| Area | Operating Regions |
|---|---|
| United States | |
| Onshore | Black Warrior Basin in Alabama<br>Arkoma Basin in Oklahoma<br>Raton Basin in New Mexico<br>Central (primarily in north Louisiana)<br>Rocky Mountains (primarily in Utah) |
| Texas Gulf Coast | South Texas |
| Offshore and south Louisiana | Gulf of Mexico (Texas and Louisiana)<br>South Louisiana |
| Brazil | Camamu, Santos, Espirito Santos and Potiguar Basins |

In Brazil, we have been successful with our drilling programs in the Santos and Camamu Basins and are pursuing gas contracts and development options in these two basins. In July 2004, we acquired the remaining 50 percent interest we did not own in UnoPaso, a Brazilian oil and gas company. While we intend to work with Petrobras, a Brazilian national energy company, in growing our presence in the Potiguar Basin with increased production and planned exploratory activity, disputes with them in other areas of our business may impact our plans.

*Natural Gas, Oil and Condensate and Natural Gas Liquids Reserves*

The tables below detail our proved reserves at December 31, 2004. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott was within four percent of our internally prepared estimates presented in these tables. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our proved properties based on value. The tables below exclude our Power segment's equity interests in Sengkang in Indonesia and Aguaytia in Peru. Combined proved reserves balances for these interests were 132,336 MMcf of natural gas and 2,195 MBbls of oil, condensate and natural gas liquids (NGL) for total natural gas equivalents of 145,507 MMcfe, all net to our ownership interests. Our estimated proved reserves as of December 31, 2004, and our 2004 production are as follows:

| | Net Proved Reserves[1] | | | | | |
|---|---|---|---|---|---|---|
| | Natural Gas | Oil/ Condensate | NGL | Total | | 2004 Production |
| | (MMcf) | (MBbls) | (MBbls) | (MMcfe) | (Percent) | (MMcfe) |
| United States | | | | | | |
| Onshore | 1,100,681 | 14,675 | 1,233 | 1,196,133 | 55 | 84,568 |
| Texas Gulf Coast | 431,508 | 3,118 | 9,874 | 509,454 | 23 | 103,286 |
| Offshore and south Louisiana | 191,652 | 9,538 | 2,094 | 261,444 | 12 | 101,140 |
| Total United States | 1,723,841 | 27,331 | 13,201 | 1,967,031 | 90 | 288,994 |
| Brazil | 68,743 | 24,171 | — | 213,769 | 10 | 8,772 |
| Total | 1,792,584 | 51,502 | 13,201 | 2,180,800 | 100 | 297,766 |

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

The table below summarizes our estimated proved producing reserves, proved non-producing reserves, and proved undeveloped reserves as of December 31, 2004:

| | Net Proved Reserves[1] | | | | |
|---|---|---|---|---|---|
| | Natural Gas | Oil/ Condensate | NGL | Total | |
| | (MMcf) | (MBbls) | (MBbls) | (MMcfe) | (Percent) |
| United States | | | | | |
| Producing | 1,085,581 | 12,507 | 10,588 | 1,224,152 | 62 |
| Non-Producing | 201,696 | 7,134 | 1,355 | 252,626 | 13 |
| Undeveloped | 436,564 | 7,690 | 1,258 | 490,253 | 25 |
| Total proved | 1,723,841 | 27,331 | 13,201 | 1,967,031 | 100 |
| Brazil | | | | | |
| Producing | 29,239 | 1,375 | — | 37,488 | 18 |
| Non-Producing | 24,988 | 1,238 | — | 32,415 | 15 |
| Undeveloped | 14,516 | 21,558 | — | 143,866 | 67 |
| Total proved | 68,743 | 24,171 | — | 213,769 | 100 |
| Worldwide | | | | | |
| Producing | 1,114,820 | 13,882 | 10,588 | 1,261,640 | 58 |
| Non-Producing | 226,684 | 8,372 | 1,355 | 285,041 | 13 |
| Undeveloped | 451,080 | 29,248 | 1,258 | 634,119 | 29 |
| Total proved | 1,792,584 | 51,502 | 13,201 | 2,180,800 | 100 |

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

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the 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 accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. 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 we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

*Acreage and Wells*

The following table details our gross and net interest in developed and undeveloped acreage at December 31, 2004. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] |
| United States | | | | | | |
| Onshore | 1,032,115 | 419,789 | 1,653,540 | 1,308,491 | 2,685,655 | 1,728,280 |
| Texas Gulf Coast | 199,035 | 82,850 | 257,225 | 172,340 | 456,260 | 255,190 |
| Offshore and south Louisiana | 643,861 | 448,599 | 744,957 | 697,515 | 1,388,818 | 1,146,114 |
| Total | 1,875,011 | 951,238 | 2,655,722 | 2,178,346 | 4,530,733 | 3,129,584 |
| Brazil | 39,476 | 13,817 | 1,346,919 | 452,552 | 1,386,395 | 466,369 |
| Worldwide Total | 1,914,487 | 965,055 | 4,002,641 | 2,630,898 | 5,917,128 | 3,595,953 |

(1) Gross interest reflects the total acreage we participated in, regardless of our ownership interests in the acreage.

(2) Net interest is the aggregate of the fractional working interest that we have in our gross acreage.

Our United States net developed acreage is concentrated primarily in the Gulf of Mexico (47 percent), Utah (14 percent), Texas (9 percent), Oklahoma (8 percent), New Mexico (7 percent) and Louisiana (7 percent). Our United States net undeveloped acreage is concentrated primarily in New Mexico (23 percent), the Gulf of Mexico (22 percent), Louisiana (12 percent), Indiana (8 percent) and Texas (8 percent). Approximately 22 percent, 9 percent and 11 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2005, 2006 and 2007.

The following table details our working interests in natural gas and oil wells at December 31, 2004:

| | Productive Natural Gas Wells | | Productive Oil Wells | | Total Productive Wells | | Number of Wells Being Drilled | |
|---|---|---|---|---|---|---|---|---|
| | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] | Gross[(1)] | Net[(2)] |
| United States | | | | | | | | |
| Onshore | 2,864 | 2,088 | 292 | 220 | 3,156 | 2,308 | 59 | 48 |
| Texas Gulf Coast | 808 | 669 | 2 | 1 | 810 | 670 | 5 | 4 |
| Offshore and south Louisiana | 287 | 194 | 75 | 41 | 362 | 235 | 4 | 1 |
| Total United States | 3,959 | 2,951 | 369 | 262 | 4,328 | 3,213 | 68 | 53 |
| Brazil | 4 | 3 | 11 | 9 | 15 | 12 | — | — |
| Worldwide Total | 3,963 | 2,954 | 380 | 271 | 4,343 | 3,225 | 68 | 53 |

(1) Gross interest reflects the total number of wells we participated in, regardless of our ownership interests in the wells.
(2) Net interest is the aggregate of the fractional working interest that we have in our gross wells.

At December 31, 2004, we operated 2,952 of the 3,225 net productive wells.

The following table details our exploratory and development wells drilled during the years 2002 through 2004:

| | Net Exploratory Wells Drilled[(1)] | | | Net Development Wells Drilled[(1)] | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| United States | | | | | | |
| Productive | 13 | 54 | 27 | 298 | 272 | 511 |
| Dry | 10 | 22 | 14 | 3 | 1 | 5 |
| Total | 23 | 76 | 41 | 301 | 273 | 516 |
| Brazil | | | | | | |
| Productive | — | 2 | — | — | — | — |
| Dry | 1 | 4 | — | — | — | — |
| Total | 1 | 6 | — | — | — | — |
| Worldwide | | | | | | |
| Productive | 13 | 56 | 27 | 298 | 272 | 511 |
| Dry | 11 | 26 | 14 | 3 | 1 | 5 |
| Total | 24 | 82 | 41 | 301 | 273 | 516 |

(1) Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.

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, Sales Prices, Transportation and Production Costs*

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

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Net Production Volumes | | | |
| United States | | | |
| Natural Gas (MMcf) | 238,009 | 338,762 | 470,082 |
| Oil, Condensate and NGL (MBbls) | 8,498 | 11,778 | 16,462 |
| Total (MMcfe) | 288,994 | 409,432 | 568,852 |
| Brazil | | | |
| Natural Gas (MMcf) | 6,848 | — | — |
| Oil, Condensate and NGL (MBbls) | 320 | — | — |
| Total (MMcfe) | 8,772 | — | — |

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Worldwide | | | |
| Natural Gas (MMcf) | 244,857 | 338,762 | 470,082 |
| Oil, Condensate and NGL (MBbls) | 8,818 | 11,778 | 16,462 |
| Total (MMcfe) | 297,766 | 409,432 | 568,852 |
| Natural Gas Average Realized Sales Price ($/Mcf)[1] | | | |
| United States | | | |
| Price, excluding hedges | $ 6.02 | $ 5.51 | $ 3.17 |
| Price, including hedges | $ 5.94 | $ 5.40 | $ 3.35 |
| Brazil | | | |
| Price, excluding hedges | $ 2.01 | $ — | $ — |
| Price, including hedges | $ 2.01 | $ — | $ — |
| Worldwide | | | |
| Price, excluding hedges | $ 5.90 | $ 5.51 | $ 3.17 |
| Price, including hedges | $ 5.83 | $ 5.40 | $ 3.35 |
| Oil, Condensate, and NGL Average Realized Sales Price ($/Bbl)[1] | | | |
| United States | | | |
| Price, excluding hedges | $ 34.44 | $ 26.64 | $ 21.38 |
| Price, including hedges | $ 34.44 | $ 25.96 | $ 21.28 |
| Brazil | | | |
| Price, excluding hedges | $ 43.01 | $ — | $ — |
| Price, including hedges | $ 39.19 | $ — | $ — |
| Worldwide | | | |
| Price, excluding hedges | $ 34.75 | $ 26.64 | $ 21.38 |
| Price, including hedges | $ 34.61 | $ 25.96 | $ 21.28 |
| Average Transportation Cost | | | |
| United States | | | |
| Natural gas ($/Mcf) | $ 0.17 | $ 0.18 | $ 0.18 |
| Oil, condensate and NGL ($/Bbl) | $ 1.16 | $ 1.05 | $ 0.97 |
| Worldwide | | | |
| Natural gas ($/Mcf) | $ 0.17 | $ 0.18 | $ 0.18 |
| Oil, condensate and NGL ($/Bbl) | $ 1.12 | $ 1.05 | $ 0.97 |
| Average Production Cost($/Mcfe)[2] | | | |
| United States | | | |
| Average lease operating cost | $ 0.62 | $ 0.42 | $ 0.42 |
| Average production taxes | 0.11 | 0.14 | 0.08 |
| Total production cost | $ 0.73 | $ 0.56 | $ 0.50 |
| Worldwide | | | |
| Average lease operating cost | $ 0.60 | $ 0.42 | $ 0.42 |
| Average production taxes | 0.11 | 0.14 | 0.08 |
| Total production cost | $ 0.71 | $ 0.56 | $ 0.50 |

(1) Prices are stated before transportation costs.

(2) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

*Acquisition, Development and Exploration Expenditures*

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

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| United States | | | |
| Acquisition Costs: | | | |
| Proved | $ 33 | $ 10 | $ 362 |
| Unproved | 32 | 35 | 29 |
| Development Costs | 395 | 668 | 1,242 |
| Exploration Costs: | | | |
| Delay Rentals | 7 | 6 | 7 |
| Seismic Acquisition and Reprocessing | 29 | 56 | 35 |
| Drilling | 149 | 405 | 482 |
| Asset Retirement Obligations[(1)] | 30 | 124 | — |
| Total full cost pool expenditures | 675 | 1,304 | 2,157 |
| Non-full cost pool expenditures | 11 | 17 | 47 |
| Total capital expenditures | $686 | $1,321 | $2,204 |
| Brazil | | | |
| Acquisition Costs: | | | |
| Proved | $ 69 | $ — | $ — |
| Unproved | 3 | 4 | 9 |
| Development Costs | 1 | — | — |
| Exploration Costs: | | | |
| Seismic Acquisition and Reprocessing | 15 | 11 | 32 |
| Drilling | 10 | 84 | 13 |
| Asset Retirement Obligations | 3 | — | — |
| Total full cost pool expenditures | 101 | 99 | 54 |
| Non-full cost pool expenditures | 3 | 1 | 2 |
| Total capital expenditures | $104 | $ 100 | $ 56 |
| Worldwide | | | |
| Acquisition Costs: | | | |
| Proved | $102 | $ 10 | $ 362 |
| Unproved | 35 | 39 | 38 |
| Development Costs | 396 | 668 | 1,242 |
| Exploration Costs: | | | |
| Delay Rentals | 7 | 6 | 7 |
| Seismic Acquisition and Reprocessing | 44 | 67 | 67 |
| Drilling | 159 | 489 | 495 |
| Asset Retirement Obligations | 33 | 124 | — |
| Total full cost pool expenditures | 776 | 1,403 | 2,211 |
| Non-full cost pool expenditures | 14 | 18 | 49 |
| Total capital expenditures | $790 | $1,421 | $2,260 |

(1) Includes an increase to our property, plant and equipment of approximately $114 million in 2003 associated with our adoption of Statement of Financial Accounting Standards No. 143.

We spent approximately $156 million in 2004, $220 million in 2003 and $275 million in 2002 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

*Regulatory and Operating Environment*

Our 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 we do 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. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our domestic 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 environmental impacts 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. Our 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 our natural gas and oil operations through their effect on the construction and operation of facilities, water disposal rights, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in material compliance with the applicable requirements. In addition, we maintain insurance to limit exposure to sudden and accidental spills and oil pollution liability.

Our production 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 property or injuries to people. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage to limit exposure to potential losses resulting from these operating hazards.

*Markets and Competition*

We primarily sell our domestic natural gas and oil to third parties through our Marketing and Trading segment at spot market prices, subject to customary adjustments. As part of our long-term business strategy, we will continue to sell our natural gas and oil production to this segment. We sell our Brazilian natural gas and oil to Petrobras, a Brazilian energy company. We sell our natural gas liquids at market prices under monthly or long-term contracts, subject to customary adjustments. We also engage in hedging activities on a portion of our natural gas and oil production to stabilize our cash flows and reduce the risk of downward commodity price movements on sales of our production.

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. Our 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 and contract terms and our ability to access drilling and other equipment on a timely and cost effective basis. 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.

**Non-regulated Business — Marketing and Trading Segment**

Our Marketing and Trading segment's operations primarily involve the marketing of our natural gas and oil production and the management of our remaining trading portfolio. Our operations in this segment over the past several years have been impacted by a number of significant events both in this business and in the industry. As a result of the deterioration of the energy trading environment in late 2001 and 2002 and the reduced availability of credit to us, we announced in November 2002 that we would reduce our involvement in the energy trading business and pursue an orderly liquidation of our historical trading portfolio. In December 2003, we announced that our historical energy trading operations would become a marketing and trading business focused on the marketing and physical trading of the natural gas and oil from our Production segment. Our Marketing and Trading segment's portfolio is grouped into several categories. Each of these categories includes contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. The types of contracts used in this segment are as follows:

- *Natural gas derivative contracts.* Our natural gas contracts include long-term obligations to deliver natural gas at fixed prices as well as derivatives related to our production activities. As of December 31, 2004, we have seven significant physical natural gas contracts with power plants. These contracts have various expiration dates ranging from 2011 to 2028, with expected obligations under individual contracts with third parties ranging from 32,000 MMBtu/d to 142,000 MMBtu/d.

  Additionally, as of December 31, 2004, we had executed contracts with third parties, primarily fixed for floating swaps, that effectively hedged approximately 244 TBtu of our Production segment's anticipated natural gas production through 2012. In addition to these hedge contracts, as of December 31, 2004, we are a party to other derivative contracts designed to provide price protection to El Paso from declines in natural gas prices in 2005 and 2006. Specifically, these contracts provide El Paso with a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006. In March 2005, we entered into additional contracts that provide El Paso a floor price of $6.00 per MMBtu on 30 TBtu of natural gas production in 2007 and a ceiling price of $9.50 per MMBtu on 60 TBtu of natural gas production in 2006.

- *Transportation-related contracts.* Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. We typically refer to the fixed reservation cost as a demand charge. As of December 31, 2004, we have contracted for 1.5 Bcf/d of capacity with contract expiration dates through 2028. Our ability to utilize our transportation capacity is dependent on several factors including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of capital needed to use this capacity and the capacity required to meet our other long-term obligations.

- *Tolling contracts.* Our tolling contracts provide us with the right to require counterparties to convert natural gas into electricity. Under these arrangements, we supply the natural gas used in the underlying power plants and sell the electricity produced by the power plant. In exchange for this right, we pay a monthly fixed fee and a variable fee based on the quantity of electricity produced. As of December 31, 2004, we have two unaffiliated physical tolling contracts, the largest of which is a contract on the Cordova power project in the Midwest. This contract expires in 2019.

- *Power and other.* Our power and other contracts include long-term obligations to provide power to our Power segment for its restructured domestic power contracts. As of December 31, 2004, we have four power supply contracts remaining, the largest being a contract with Morgan Stanley for approximately 1,700 MMWh per year extending through 2016. In the first quarter of 2005, we sold two of these contracts related to subsidiaries in our Power segment, Cedar Brakes I and II. We also have other contracts that require the physical delivery of power or that are used to manage the risk associated with our obligations to supply power. In addition, we have natural gas storage contracts that provide capacity of approximately 4.7 Bcf of storage for operational and balancing purposes.

*Markets and Competition*

Our Marketing and Trading segment operates in a highly competitive environment, competing on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served is influenced directly or indirectly by energy market economics. Our primary competitors include:

- Affiliates of major oil and natural gas producers;
- Large domestic and foreign utility companies;
- Affiliates of large local distribution companies;
- Affiliates of other interstate and intrastate pipelines; and
- Independent energy marketers and power producers with varying scopes of operations and financial resources.

### Non-regulated Business — Power Segment

Our Power segment includes the ownership and operation of international and domestic power generation facilities as well as the management of restructured power contracts. As of December 31, 2004, we owned or had interests in 37 power facilities in 16 countries with a total generating capacity of approximately 10,400 gross MW. Our commercial focus has historically been either to develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing above-market power purchase agreements. However, during 2004, we completed the sale of substantially all of our domestic power generation facilities and a significant portion of our domestic power restructuring business. We will continue to evaluate potential opportunities to sell or otherwise divest the remaining domestic assets and a number of international assets, such that our long-term focus will be on maximizing the value of our power assets in Brazil.

*International Power.* As of December 31, 2004, we owned or had a direct investment in the following international power plants (only significant assets and investments are listed):

| Project | Country | El Paso Ownership Interest | Gross Capacity | Power Purchaser | Expiration Year of Power Sales Contracts | Fuel Type |
|---|---|---|---|---|---|---|
| | | (Percent) | (MW) | | | |
| *Brazil* | | | | | | |
| Araucaria[1] | Brazil | 60 | 484 | Copel | —[2] | Natural Gas |
| Macae | Brazil | 100 | 928 | Petrobras[3] | 2007[2] | Natural Gas |
| Manaus | Brazil | 100 | 238 | Manaus Energia[4] | 2008 | Oil |
| Porto Velho[1] | Brazil | 50 | 404 | Eletronorte | 2010, 2023 | Oil |
| Rio Negro | Brazil | 100 | 158 | Manaus Energia[4] | 2008 | Oil |
| *Asia* | | | | | | |
| Fauji[1] | Pakistan | 42 | 157 | Pakistan Water and Power | 2029 | Natural Gas |
| Habibullah[1] | Pakistan | 50 | 136 | Pakistan Water and Power | 2029 | Natural Gas |
| KIECO[1] | South Korea | 50 | 1,720 | KEPCO | 2020 | Natural Gas |
| Meizhou Wan[1] | China | 26 | 734 | Fujian Power | 2025 | Coal |
| Haripur[1] | Bangladesh | 50 | 116 | Bangladesh Power | 2014 | Natural Gas |
| PPN[1][5] | India | 26 | 325 | Tamil Nadu | 2031 | Naphtha/Natural Gas |
| Saba[1] | Pakistan | 94 | 128 | Pakistan Water and Power | 2029 | Oil |
| Sengkang[1] | Indonesia | 48 | 135 | PLN | 2022 | Natural Gas |
| *Central and other South America* | | | | | | |
| Aguaytia[1] | Peru | 24 | 155 | Various | 2005, 2006 | Natural Gas |
| Fortuna[1] | Panama | 25 | 300 | Union Fenosa | 2005, 2008 | Hydroelectric |
| Itabo[1] | Dominican Republic | 25 | 416 | CDEEE and AES | 2016 | Oil/Coal |
| Nejapa | El Salvador | 87 | 144 | AES and PPL | 2005 | Oil |
| *Europe* | | | | | | |
| Enfield[1] | United Kingdom | 25 | 378 | Spot Market | — | Natural Gas |
| EMA[1] | Hungary | 50 | 69 | Dunaferr Energy Services | 2016 | Natural Gas/Oil |

(1) These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.
(2) These facilities' power sales contracts are currently in arbitration.
(3) Although a majority of the power generated by this power facility is sold to the wholesale power markets, Petrobras provides a minimum level of revenue under its contract until 2007. Petrobras did not make their December 2004 and January 2005 payments under this contract and have filed a lawsuit and for arbitration. See Part II, Item 8, Financial Statements and Supplementary Data, Note 17 for a further discussion of this matter.
(4) These power facilities have new power purchase agreements that were signed in January 2005 extending the terms of the contract through 2008 at which time we will transfer ownership of the plants to Manaus Energia.
(5) We sold our investment in this plant in the first quarter of 2005.

In addition to the international power plants above, our Power segment also has investments in the following international pipelines:

| Pipeline | El Paso Ownership Interest | Miles of Pipeline | Design Capacity[1] | Average 2004 Throughput[1] |
|---|---|---|---|---|
| | (Percent) | | (MMcf/d) | (BBtu/d) |
| Bolivia to Brazil | 8 | 1,957 | 1,059 | 722 |
| Argentina to Chile | 22 | 336 | 124 | 77 |

(1) Volumes represent the pipeline's total design capacity and average throughput and are not adjusted for our ownership interest.

*Domestic Power Plants.* During 2004, we sold substantially all of our domestic power assets. As of December 31, 2004, we owned or had a direct investment in the following domestic power facilities (only significant assets and investments are listed):

| Project | State | El Paso Ownership Interest | Gross Capacity | Power Purchaser | Expiration Year of Power Sales Contracts | Fuel Type |
|---|---|---|---|---|---|---|
| | | (Percent) | (MW) | | | |
| Berkshire[1] | MA | 56 | 261 | —[2] | —[2] | Natural Gas |
| Midland Cogeneration[1] | MI | 44 | 1,575 | Consumers Power, Dow | 2025 | Natural Gas |
| CDECCA[3] | CT | 100 | 62 | —[2] | —[2] | Natural Gas |
| Pawtucket[3] | RI | 100 | 69 | —[2] | —[2] | Natural Gas |
| San Joaquin[3] | CA | 100 | 48 | —[2] | —[2] | Natural Gas |
| Eagle Point[4] | NJ | 100 | 233 | —[2] | —[2] | Natural Gas |
| Rensselaer[4] | NY | 100 | 86 | —[2] | —[2] | Natural Gas |

(1) These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.
(2) These power facilities (referred to as merchant plants) do not have long-term power purchase agreements with third parties. Our Marketing and Trading segment sells the power that a majority of these facilities generate to the wholesale power market.
(3) These plants have Board approval for sale and are targeted to be sold in the first half of 2005. We have executed sales agreements on the Pawtucket and San Joaquin facilities.
(4) These plants were sold in the first quarter of 2005.

*Domestic Power Contract Restructuring.* In addition to our domestic power plants, we were historically involved in a power restructuring business. This business involved restructuring above-market, long-term power purchase agreements with utilities that were originally tied to older power plants built under the Public Utility Regulatory Policies Act of 1978 (PURPA). These PURPA facilities were typically less efficient and more costly to operate than newer power generation facilities.

While we are no longer actively restructuring additional power purchase contracts, we continue to manage the purchase and sale of electricity required under the contracts related to Cedar Brakes I and II and continue to perform under the Mohawk River Funding II contracts. We also retained an interest in Mohawk River Funding III, which is an entity that currently has a claim against an entity in bankruptcy related to a previously restructured power contract. During 2004, we completed the sale of Utility Contract Funding (UCF) and signed binding agreements to sell Cedar Brakes I and II. We completed the sale of Cedar Brakes I and II in the first quarter of 2005.

### *Regulatory Environment & Markets and Competition*

*International.* Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of these countries have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures are subject to change (including differing interpretations) over time.

Many of our international power generation facilities sell power under long-term power purchase agreements primarily with power transmission and distribution companies owned by the local governments where the facilities are located. When these long-term contracts expire, these facilities will be subject to regional market, competitive and political risks.

*Domestic.* Our domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to the rates, terms and conditions of service of these regulated plants. Our cogeneration power production activities are regulated by the FERC under PURPA with respect to rates, procurement and provision of services and operating standards. Our power generation activities are also subject to federal, state and local environmental regulations.

**Non-regulated Business — Field Services Segment**

Our Field Services segment conducts our midstream activities, which include gathering and processing of natural gas for natural gas producers, primarily in the south Louisiana production area, and held our ownership interests in Enterprise Products Partners, a publicly traded master limited partnership.

*Gathering and Processing Assets.* As of December 31, 2004, our gathering systems consisted of 240 miles of pipeline with 665 MMcfe/d of throughput capacity. These systems had average throughput of 203 BBtue/d during 2004. Our processing facilities had operational capacity and volumes as follows:

| Processing Plants | Inlet Capacity December 31, 2004 | Average Inlet Volume | | | Average Sales | | |
|---|---|---|---|---|---|---|---|
| | | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (MMcfe/d) | | (BBtue/d) | | | (Mgal/d) | |
| South Louisiana | 2,550 | 1,600 | 1,627 | 1,407 | 1,631 | 1,726 | 1,604 |
| Other areas[1] | 186 | 1,180 | 1,579 | 2,513 | 2,460 | 2,611 | 5,134 |
| Total | 2,736 | 2,780 | 3,206 | 3,920 | 4,091 | 4,337 | 6,738 |

(1) During 2002, 2003 and 2004, we sold a substantial amount of our midstream assets to GulfTerra and Enterprise. Included in the volume and sales columns is activity through the sale date for the assets which were sold.

In January 2005, we sold to Enterprise the membership interests in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs gathering and processing facilities.

*General and Limited Partner Interests in Enterprise Products Partners, L.P.* During 2003, and through September 2004, we held significant interests in GulfTerra Energy Partners, L.P. In September 2004, GulfTerra merged with Enterprise Products Partners, and we sold our ownership interests in GulfTerra along with our interests in processing assets in South Texas in exchange for cash, a 9.9 percent general partner interest in Enterprise, and 13.5 million units in Enterprise. In January 2005, we sold all of our interests in Enterprise and its general partner for cash.

*Regulatory Environment.* Some of our operations, owned directly or through equity investments, are subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of our operations, owned directly or through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979 and various environmental statutes and regulations. Each of our pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and we believe that these systems are in material compliance with the applicable requirements.

*Markets and Competition.* We compete with major interstate and intrastate pipeline companies in transporting natural gas and NGL. We also compete 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 NGL. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling and production activity, customer service and access to favorable downstream markets.

**Other Operations and Assets**

We currently have a number of other assets and businesses that are either included as part of our corporate activities or as discontinued operations.

*Corporate Activities*

Our corporate operations include our general and administrative functions as well as a telecommunications business, a telecommunications facility in Chicago and various other contracts and assets, including those related to our financial services, petroleum ship charter and LNG operations, all of which are insignificant to our results in 2004.

*Discontinued Operations*

Our discontinued operations consist of our petroleum markets business and international natural gas and oil production operations, primarily in Canada.

## Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 17, and is incorporated herein by reference.

## Employees

As of March 23, 2005, we had approximately 6,400 full-time employees, of which 362 employees in Brazil are subject to collective bargaining arrangements.

## Executive Officers of the Registrant

Our executive officers as of March 23, 2005, are listed below. Prior to August 1, 1998, all references to El Paso refer to positions held with El Paso Natural Gas Company.

| Name | Office | Officer Since | Age |
|---|---|---|---|
| Douglas L. Foshee | President and Chief Executive Officer of El Paso | 2003 | 45 |
| D. Dwight Scott | Executive Vice President and Chief Financial Officer of El Paso | 2002 | 41 |
| Robert W. Baker | Executive Vice President and General Counsel of El Paso | 1996 | 48 |
| John W. Somerhalder II | Executive Vice President of El Paso and President of El Paso Pipeline Group | 1990 | 48 |
| Lisa A. Stewart | Executive Vice President of El Paso and President of El Paso Production and Non-Regulated Operations | 2004 | 47 |

Douglas L. Foshee has been President, Chief Executive Officer, and a Director of El Paso since September 2003. Mr. Foshee became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. In December 2003, several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, filed for bankruptcy protection, whereby the subsidiaries jointly resolved their asbestos claims. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer, and Chairman of the Board at Nuevo Energy Company. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Operating Officer and Chief Executive Officer.

D. Dwight Scott has been Executive Vice President and Chief Financial Officer of El Paso since October 2002. Mr. Scott served as Senior Vice President of Finance and Planning for El Paso from July 2002 to September 2002. Mr. Scott was Executive Vice President of Power for El Paso Merchant Energy from December 2001 to June 2002, and he served as Chief Financial Officer of El Paso Global Networks from October 2000 to November 2001. Prior to that, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

Robert W. Baker has been Executive Vice President and General Counsel of El Paso since January 2004. From February 2003 to December 2003, he served as Executive Vice President of El Paso and President of El Paso Merchant Energy. He was Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time he held various positions in the legal department of Tenneco Energy and El Paso since 1983.

John W. Somerhalder II has been an Executive Vice President of El Paso since April 2000, and President of the Pipeline Group since January 2001. He has been Chairman of the Board of Tennessee Gas Pipeline Company, El Paso Natural Gas Company and Southern Natural Gas Company since January 2000 and Chairman of the Board of ANR Pipeline Company and Colorado Interstate Gas Company since January 2001. Prior to that, he was President of Tennessee Gas Pipeline Company and worked in other executive positions in El Paso since 1996.

Lisa A. Stewart has been an Executive Vice President of El Paso since November 2004, and President of El Paso Production and Non-Regulated Operations since February 2004. Ms. Stewart was Executive Vice President of Business Development and Exploration and Production Services for Apache Corporation from 1995 to February 2004. From 1984 to 1995, Ms. Stewart worked in various positions for Apache Corporation.

**Available Information**

Our website is http://www.elpaso.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the SEC. Information about each of our Board members, as well as each of our Board's standing committee charters, our Corporate Governance Guidelines and our Code of Business Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

## 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 taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

## ITEM 3. LEGAL PROCEEDINGS

Details of the cases listed below, as well as a description of our other legal proceedings are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 17, and is incorporated herein by reference.

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; and

*Sandra Joan Malin Revocable Trust, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 1, 2002; *Lee S. Shalov, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 15, 2002; *Paul C. Scott, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 22, 2002; *Brenda Greenblatt, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed August 23, 2002; *Stefanie Beck, et al v. El Paso Corporation, William Wise, and H. Brent Austin,* filed August 23, 2002; *J. Wayne Knowles, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine,* filed September 13, 2002; *The Ezra Charitable Trust, et al v. El Paso Corporation, William Wise, Rodney D. Erskine and H. Brent Austin,* filed October 4, 2002. The purported shareholder class actions relating to our reserve restatement filed in the U.S. District Court for the Southern District of Texas, Houston Division, which have now been consolidated with the above referenced purported shareholder class actions, are: *James Felton v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Sinclair Haberman v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Patrick Hinner v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Stanley Peltz v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Yolanda Cifarelli v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Andrew W. Albstein v. El Paso Corporation, William Wise; George S. Johnson v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, and D. Dwight Scott; Robert Corwin v. El Paso Corporation, Mark Leland, Brent Austin; Ronald Kuehn, Jr., D. Dwight Scott and William Wise; Michael Copland v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; Leslie Turbowitz v. El Paso Corporation, Mark Leland, Brent Austin, Ronald Kuehn, Jr., D. Dwight Scott and William Wise; David Sadek v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott; Stanley Sved v. El Paso Corporation, Ronald Kuehn, Jr., and William Wise; Nancy Gougler v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee and D. Dwight Scott; William Sinnreich v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; Joseph Fisher v. El Paso Corporation, Ronald Kuehn, Jr., Douglas Foshee, D. Dwight Scott and William Wise; and Glickenhaus & Co. v. El Paso Corporation, Rod Erskine, Ronald Kuehn, Jr., Brent Austin, William Wise, Douglas Foshee and D. Dwight Scott; Haberman v. El Paso Corporation et al and Thompson v. El Paso Corporation et al.* The purported shareholder action filed in the Southern District of New York is *IRA F.B.O. Michael Conner et al v. El Paso Corporation, William Wise, H. Brent Austin, Jeffrey Beason, Ralph Eads, D. Dwight Scott, Credit Suisse First Boston, J.P. Morgan Securities,* filed October 25, 2002.

The stayed shareholder derivative actions filed in the United States District Court for the Southern District of Texas, Houston Division are *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott,* filed August 22, 2002, and *Russo v. William Wise, Brent Austin, Dwight Scott, Ralph Eads, Ronald Kuehn, Jr., Douglas Foshee, Rodney Erskine, PricewaterhouseCoopers and El Paso Corporation* filed in September 2004. The consolidated shareholder derivative action filed in Houston is *John Gebhart and Marilyn Clark v. El Paso Natural Gas, El Paso Merchant Energy, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn, Jr., J. Carleton MacNeil, Jr., Thomas McDade, Malcolm Wallop, William Wise, Joe Wyatt, Ralph Eads, Brent Austin and John Somerhalder* filed in November 2002. The stayed shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

*Environmental Proceedings*

*Kentucky PCB Project.* In November 1988, the Kentucky Natural Resources and Environmental Protection Cabinet filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs and a civil penalty. TGP entered into interim agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under a 1994 consent order with the Environmental Protection Agency (EPA). Despite TGP's remediation efforts, the agency may raise additional technical issues or seek additional remediation work and/or penalties in the future.

*Toca Air Permit Violation.* In June 2003, SNG notified the Louisiana Department of Environmental Quality (LDEQ) that it had discovered possible compliance issues with respect to operations at its Toca Compressor Station. In December 2003, LDEQ issued a Consolidated Compliance Order and Notice of Potential Penalty. SNG's Toca Compressor Station will invest an estimated $6 million to upgrade the station's environmental controls in 2005. SNG filed a revised permit application and plan for compliance in January 2004 and paid a penalty of $66,000, resolving the matter.

*Shoup Natural Gas Processing Plant.* On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to exceeding the emission limit, testing, reporting, and recordkeeping issues in 2001. On December 29, 2004, TCEQ issued an Executive Director's Preliminary Report and Petition revising the allegations from the NOE and seeking a penalty of $419,650. We have answered the Petition, disputing the alleged violations and the proposed penalty.

*Corpus Christi Refinery Air Violations.* On March 18, 2004, the Texas Commission on Environmental Quality issued an "Executive Director's Preliminary Report and Petition" seeking $645,477 in penalties relating to air violations alleged to have occurred at our former Corpus Christi, Texas refinery from 1996 to 2000. We filed a hearing request to protect our procedural rights. Pursuant to discussions on March 16, 2005, the parties have reached an agreement in principle to resolve the allegations for $272,097. The parties are drafting the final settlement document formalizing the agreement.

*Coastal Eagle Point Air Issues.* Pursuant to the EPA's Petroleum Refinery Initiative, our former Eagle Point refinery resolved certain claims of the U.S. and the State of New Jersey in a Consent Decree entered in December 2003. The Eagle Point refinery will invest an estimated $3 million to $7 million to upgrade the plant's environmental controls by 2008. The Eagle Point Refinery was sold in January 2004. We will share certain future costs associated with implementation of the Consent Decree pursuant to the Purchase and Sale Agreement. On April 1, 2004, the New Jersey Department of Environmental Protection issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking $183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003, prior to the sale. We have filed an administrative appeal contesting the penalty.

*St. Helens.* On November 11, 2003, our St. Helens, Oregon chemical plant discovered a release of ammonia at the facility and reported the release to the National Response Center and state and local contacts on November 12, 2003. On December 3, 2003, the St. Helens plant was sold to Dyno Nobel, Inc. On April 21, 2004, the EPA issued a demand to El Paso Merchant Energy — Petroleum Company for penalties for alleged reporting violations. We responded to the EPA's demand, and we have fully resolved the alleged violations by paying a penalty of $50,345 and conducting a supplemental project costing $59,581.

*Natural Buttes.* On May 19, 2003, we met with the EPA to discuss potential "prevention of significant deterioration" violations due to a de-bottlenecking modification at Colorado Interstate Gas Company's facility. The EPA issued an Administrative Compliance Order. We are in negotiations with the EPA as to the appropriate penalty and have reserved our anticipated settlement amount.

*Air Permit Violation.* In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. The hearing has been stayed by agreement to allow El Paso Production Company and LDEQ time to possibly settle this matter. Negotiations are on-going for resolving this matter.

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

We held our annual meeting of stockholders on November 18, 2004. Proposals presented for a stockholders' vote included the election of twelve directors, ratification of the appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2004, and two stockholder proposals.

Each of the twelve incumbent directors nominated by El Paso was elected with the following voting results:

| Nominee | For | Withheld |
|---|---|---|
| John M. Bissell | 484,639,859 | 101,741,034 |
| Juan Carlos Braniff | 485,212,690 | 101,168,202 |
| James L. Dunlap | 503,715,688 | 82,665,204 |
| Douglas L. Foshee | 564,694,430 | 21,686,462 |
| Robert W. Goldman | 503,086,283 | 83,294,609 |
| Anthony W. Hall, Jr. | 490,112,165 | 96,268,727 |
| Thomas R. Hix | 563,913,752 | 22,467,140 |
| William H. Joyce | 564,050,375 | 22,330,518 |
| Ronald L. Kuehn, Jr. | 483,437,462 | 102,943,431 |
| J. Michael Talbert | 503,779,161 | 82,601,731 |
| John L. Whitmire | 502,420,108 | 83,960,784 |
| Joe B. Wyatt | 487,881,511 | 98,499,382 |

The appointment of PricewaterhouseCoopers LLP as El Paso's independent certified public accountants for the fiscal year 2004 was ratified with the following voting results:

| | For | Against | Abstain |
|---|---|---|---|
| Proposal to ratify the appointment of PricewaterhouseCoopers LLP as independent certified public accountants | 512,328,324 | 68,245,737 | 5,806,831 |

There were no broker non-votes for the ratification of PricewaterhouseCoopers LLP.

Two proposals submitted by stockholders were presented for a stockholder vote. One proposal called for stockholder approval of expensing the costs of all future stock options in the annual income statement. The second proposal called for stockholder approval regarding Commonsense Executive Compensation. The first stockholder proposal was approved and the second stockholder proposal was not approved with the following voting results:

| | For | Against | Abstain |
|---|---|---|---|
| Stockholder proposal regarding expensing stock options | 303,127,387 | 125,027,119 | 12,236,275 |
| Stockholder proposal regarding Commonsense Executive Compensation | 50,700,938 | 379,536,201 | 10,153,643 |

We are currently working toward the adoption of an accounting standard on July 1, 2005 that, once adopted, will result in the expensing of all stock options and other stock based compensation. For a further discussion of this standard, see Part II, Item 8, Financial Statements and Supplementary Data, Note 1.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of March 23, 2005, we had 48,629 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

The following table reflects the quarterly high and low sales prices for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange and the cash dividends we declared in each quarter:

| | High | Low | Dividends |
|---|---|---|---|
| | | (Per share) | |
| **2004** | | | |
| Fourth Quarter | $11.85 | $ 8.42 | $ 0.04 |
| Third Quarter | 9.20 | 7.37 | 0.04 |
| Second Quarter | 7.95 | 6.58 | 0.04 |
| First Quarter | 9.88 | 6.57 | 0.04 |
| **2003** | | | |
| Fourth Quarter | $ 8.29 | $ 5.97 | $ 0.04 |
| Third Quarter | 8.95 | 6.51 | 0.04 |
| Second Quarter | 9.89 | 5.85 | 0.04 |
| First Quarter | 10.30 | 3.33 | 0.04 |

On February 18, 2005, we declared a quarterly dividend of $0.04 per share of our common stock, payable on April 5, 2005, to shareholders of record as of March 4, 2005. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

*Odd-lot Sales Program*

We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. This voluntary program offers these stockholders a convenient method to sell all of their odd-lot shares at one time without incurring any brokerage costs. We also have a dividend reinvestment and common stock purchase plan available to all of our common stockholders of record. This voluntary plan provides our stockholders a convenient and economical means of increasing their holdings in our common stock. Neither the odd-lot program nor the dividend reinvestment and common stock purchase plan have a termination date; however, we may suspend either at any time. You should direct your inquiries to Fleet National Bank, care of EquiServe, our exchange agent at 1-877-453-1503.

## ITEM 6. SELECTED FINANCIAL DATA

The following historical selected financial data excludes certain of our international natural gas and oil production operations and our petroleum markets and coal mining businesses, which are presented as discontinued operations in our financial statements for all periods. The selected financial data below should be read together with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data included in this Report on Form 10-K/A. These selected historical results are not necessarily indicative of results to be expected in the future.

| | As of or for the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 (Restated)[1][2] | 2002 (Restated)[1] | 2001 | 2000[3] |
| | (In millions, except per common share amounts) | | | | |
| Operating Results Data: | | | | | |
| Operating revenues | $ 5,874 | $ 6,668 | $ 6,881 | $10,186 | $ 6,179 |
| Income (loss) from continuing operations available to common stockholders[4] | $ (802) | $ (605) | $(1,242) | $ (223) | $ 481 |
| Net income (loss) | $ (948) | $(1,928) | $(1,875) | $ (447) | $ 665 |
| Basic income (loss) per common share from continuing operations | $ (1.25) | $ (1.01) | $ (2.22) | $ (0.44) | $ 0.98 |
| Diluted income (loss) per common share from continuing operations | $ (1.25) | $ (1.01) | $ (2.22) | $ (0.44) | $ 0.95 |
| Cash dividends declared per common share[5] | $ 0.16 | $ 0.16 | $ 0.87 | $ 0.85 | $ 0.82 |
| Basic average common shares outstanding | 639 | 597 | 560 | 505 | 494 |
| Diluted average common shares outstanding | 639 | 597 | 560 | 505 | 506 |
| Financial Position Data: | | | | | |
| Total assets[6] | $31,383 | $36,942 | $41,923 | $44,271 | $43,992 |
| Long-term financing obligations[7] | 18,241 | 20,275 | 16,106 | 12,840 | 11,206 |
| Securities of subsidiaries[7] | 367 | 447 | 3,420 | 4,013 | 3,707 |
| Stockholders' equity | 3,439 | 4,352 | 5,749 | 6,666 | 6,145 |

(1) During the completion of the financial statements for the year ended December 31, 2004, we identified an error in the manner in which we had originally adopted the provisions of SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, in 2002. Upon adoption of these standards, we incorrectly adjusted the cost of investments in unconsolidated affiliates and the cumulative effect of change in accounting principle for the excess of our share of the affiliates fair value of the net assets over their original cost, which we believed was negative goodwill. The amount originally recorded as a cumulative effect of accounting change was $154 million and related to our investments in Citrus Corporation, Portland Natural Gas, several Australian investments and an investment in the Korea Independent Energy Corporation. We subsequently determined that the amounts we adjusted were not negative goodwill, but rather amounts that should have been allocated to the long-lived assets underlying our investments. As a result, we were required to restate our 2002 financial statements to reverse the amount we recorded as a cumulative effect of an accounting change on January 1, 2002. This adjustment also impacted a deferred tax adjustment and an unrealized loss we recorded on our Australian investments during 2002, requiring a further restatement of that year. The restatements also affected the investment, deferred tax liability and stockholders' equity balances we reported as of December 31, 2002 and 2003. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatements.

(2) We also identified an error in the manner in which we had originally reported certain of our income taxes associated with our discontinued Canadian exploration and production operations for the year ended December 31, 2003. We incorrectly included approximately $82 million of deferred tax benefits in continuing operations in the fourth quarter of 2003 that should have been reflected in discontinued operations. As a result, we were required to restate our 2003 financial statements, and related quarterly financial information, to reclassify this amount from continuing operations to discontinued operations. This restatement did not impact our reported net loss or balance sheet amounts as of and for the year ended December 31, 2003. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatement.

(3) These amounts are derived from unaudited financial statements. Such amounts were restated in 2003 for the accounting impact of adjustments to our historical reserve estimates.

(4) We incurred losses of $1.1 billion in 2004, $1.2 billion in 2003 and $0.9 billion in 2002 related to impairments of assets and equity investments as well as restructuring charges related to industry changes and the related realignment of our businesses in response to those changes. In 2003, we also entered into an agreement in principle to settle claims associated with the western energy crisis of 2000 and 2001. This settlement resulted in charges of $104 million in 2003 and $899 million in 2002, both before income taxes. In addition, we incurred ceiling test charges of $5 million, $5 million and $1,895 million in 2003, 2002 and 2001 on our full cost natural gas and oil properties. During 2001, we merged with The Coastal Corporation and incurred costs and asset impairments related to this merger that totaled approximately $1.5 billion. For further discussions of events affecting comparability of our results in 2004, 2003 and 2002, see Part II, Item 8, Financial Statements and Supplementary Data, Notes 2 through 5.

(5) Cash dividends declared per share of common stock represent the historical dividends declared by El Paso for all periods presented.

(6) Decreases in 2002, 2003 and 2004 were a result of asset sales activities during these periods. See Part II, Item 8, Financial Statements and Supplementary Data, Note 3.

(7) The increases in total long-term financing obligations in 2002 and 2003 was a result of the consolidations of our Chaparral and Gemstone power investments, the restructuring of other financing transactions, and the reclassification of securities of subsidiaries as a result of our adoption of SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,* during 2003.

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

Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed beginning on page 76.

### Overview

Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own North America's largest natural gas pipeline system and are a large independent natural gas producer. We also own and operate an energy marketing and trading business, a power business, midstream assets and investments, and have an investment in a small telecommunications business. Our power business primarily consists of international assets.

Since the end of 2001, our business activities have largely been focused on maintaining our core businesses of pipelines and production, while attempting to liquidate or otherwise divest of those businesses and operations that were not core to our long-term objectives, or that were not performing consistently with the expectations we had for them at the time we made the investment. Our overall objective during this period has been to reduce debt and improve liquidity, while at the same time invest in our core business activities. Our actions during this period have significantly impacted our financial condition, with the sale of almost $10 billion of operating assets. These actions have also resulted in significant financial losses through asset impairments, realized losses on asset sales and reduction of income from the businesses sold.

We believe that 2004 was a watershed year for us. We were able to meet and exceed a number of the goals established under our 2003 Long Range Plan. As part of our efforts in 2004:

- We focused capital investment on our core pipeline and production businesses, where in 2002, 2003 and 2004, we spent 87 percent, 91 percent, and 97 percent of our total capital dollars;

- We completed the sale of a number of assets and investments including international production properties, a substantial portion of our general and limited partnership interests in GulfTerra, a significant portion of our worldwide petroleum markets operations, a significant portion of our domestic power generation operations and our merchant LNG business. Total proceeds from these sales were approximately $3.3 billion;

- We reduced our net debt (debt, net of cash) by $3.4 billion in 2004, lowering our net debt to $17.1 billion as of December 31, 2004; and

- We continued our cost-reduction efforts with a goal of achieving $150 million of savings by the end of 2006.

As noted above, in 2004, we focused on expanding our pipeline operations and beginning the turnaround of our production business. During the year, we completed major expansions in our pipeline operations, including our Cheyenne Plains project to provide transmission outlets for natural gas supply in the Rocky Mountains, and we are moving forward on our Seafarer and Cypress projects to fulfill demand for natural gas in the southeastern United States, primarily Florida. Additionally, we continue to work in recontracting capacity on our systems and have been successful to date in these efforts. In our production operations, we instituted a new, more rigorous, risk analysis process which emphasizes strict capital discipline. Over the second half of 2004, this process resulted in a shifting of capital to areas with higher returns, improved drilling results and helped us to begin the stabilization of our domestic production. In addition, we have recently made several strategic acquisitions of production properties in Texas. In 2005, we will continue to work to achieve our long-range goals by:

- Simplifying our capital structure;
- Continuing to focus on expansions in our core pipeline business and completing the turnaround of our production business;
- Selling additional assets that we expect will generate proceeds from $1.8 billion to $2.2 billion;
- Reducing outstanding debt (net of cash) to $15 billion by the end of 2005; and
- Continuing to reduce costs to achieve the cost savings outlined in our plan.

## Capital Resources and Liquidity

We rely on cash generated from our internal operations as our primary source of liquidity, as well as available credit facilities, project and bank financings, proceeds from asset sales and the issuance of long-term debt, preferred securities and equity securities. From time to time, we have also used structured financing transactions that are sometimes referred to as off-balance sheet arrangements. We expect that our future funding for working capital needs, capital expenditures, long-term debt repayments, dividends and other financing activities will continue to be provided from some or all of these sources, although we do not expect to use off-balance sheet arrangements to the same degree in the future. Each of our existing and projected sources of cash are impacted by operational and financial risks that influence the overall amount of cash generated and the capital available to us. For example, cash generated by our business operations may be impacted by, among other things, changes in commodity prices, demands for our commodities or services, success in recontracting existing contracts, drilling success and competition from other providers or alternative energy sources. Collateral demands or recovery of cash posted as collateral are impacted by natural gas prices, hedging levels and the credit quality of us and our counterparties. Cash generated by future asset sales may depend on the condition and location of the assets and the number of interested buyers. In addition, our future liquidity will be impacted by our ability to access capital markets which may be restricted due to our credit ratings, general market conditions, and by limitations on our ability to access our existing shelf registration statement as further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 15. For a further discussion of risks that can impact our liquidity, see our risk factors beginning on page 83.

Our subsidiaries are a significant potential source of liquidity to us and they participate in our cash management program to the extent they are permitted under their financing agreements and indentures. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or requirements, we either provide cash to them or they provide cash to us.

During 2004, we took additional steps to reduce our overall debt obligations. These actions included entering into a new $3 billion credit agreement and selling entities with substantial debt obligations as follows (in millions):

| | |
|---|---|
| Debt obligations as of December 31, 2003 | $21,732 |
| Principal amounts borrowed[(1)] | 1,513 |
| Repayment of principal[(2)] | (3,370) |
| Sale of entities[(3)] | (887) |
| Other | 208 |
| Total debt as of December 31, 2004 | $19,196 |

(1) Includes proceeds from a $1.25 billion term loan under our new $3 billion credit agreement.
(2) Includes $850 million of repayments under our previous $3 billion revolving credit facility.
(3) Consists of $815 million of debt related to Utility Contract Funding and $72 million of debt related to Mohawk River Funding IV.

For a further discussion of our long-term debt, other financing obligations and other credit facilities, see Part II, Item 8, Financial Statements and Supplementary Data, Note 15.

As of December 31, 2004, we had available liquidity as follows (in billions):

| | |
|---|---|
| Available cash | $1.8 |
| Available capacity under our $3 billion credit agreement | 0.6 |
| Net available liquidity at December 31, 2004 | $2.4 |

In addition to our available liquidity, we expect to generate significant operating cash flow in 2005. We will supplement this operating cash flow with proceeds from asset sales, which we expect will range from $1.8 billion to $2.2 billion over the next 12 to 24 months (of which $0.7 billion has already closed through March 25, 2005). We will also utilize proceeds from our financing activities as needed. In March 2005, we completed a $200 million financing at CIG. The proceeds will be used to refinance $180 million of bonds at CIG that will mature in June 2005 and for other general purposes.

In 2005 we expect to spend between $1.6 billion and $1.7 billion on capital investments mainly in our core pipeline and production businesses. We have also spent approximately $0.3 billion on acquisitions in our natural gas and oil operations in 2005, and may make additional acquisitions during 2005. As of December 31, 2004, our contractual debt maturities for 2005 and 2006 were approximately $0.6 billion and $1.3 billion. Additionally, we had approximately $0.8 billion of zero-coupon debentures that have a stated maturity of 2021, but contain an option whereby the holders can require us to redeem the obligations in February 2006. We currently expect the holders to exercise this right, which combined with our contractual maturities could require us to retire up to $2.1 billion of debt in 2006. So far, in 2005 we have prepaid approximately $0.7 billion of our Euro denominated debt originally scheduled to mature in March 2006 and $0.2 billion of our zero-coupon debentures. As a result of these prepayments, we have reduced our 2006 expected maturities to approximately $1.2 billion which will give us greater financial flexibility next year.

Finally, in 2005 we may also prepay a number of other obligations including derivative positions in our marketing and trading operations and possibly amounts outstanding for the Western Energy Settlement, among other items. These prepayments could total approximately $1.1 billion. Of this amount, we have already prepaid approximately $240 million of obligations through the transfer of derivative contracts to Constellation Power in March 2005, in connection with the sale of Cedar Brakes I and II.

Our net available liquidity includes our $3 billion credit agreement. As of December 31, 2004, we had borrowed $1.25 billion as a term loan and issued approximately $1.2 billion of letters of credit under this agreement. The availability of borrowings under this credit agreement and our ability to incur additional debt is subject to various conditions as further described in Part II, Item 8, Financial Statements and Supplementary Data, Note 15, which we currently meet. These conditions include compliance with the financial covenants and ratios required by those agreements, absence of default under the agreements, and continued accuracy of the representations and warranties contained in the agreements. The financial coverage ratios under our $3 billion credit agreement change over time. However, these covenants currently require our Debt to Consolidated EBITDA not to exceed 6.5 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in the credit agreement. As of December 31, 2004, our ratio of Debt to Consolidated EBITDA was 4.85 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 1.93 to 1.

Our $3 billion credit agreement is collateralized by our equity interests in TGP, EPNG, ANR, CIG, WIC, Southern Gas Storage Company, and ANR Storage Company. Based upon a review of the covenants contained in our indentures and our other financing obligations, acceleration of the outstanding amounts under the credit agreement could constitute an event of default under some of our other debt agreements. If there was an event of default and the lenders under the credit agreement were to exercise their rights to the collateral, we could be required to liquidate our interests in these entities that collateralize the credit agreement. Additionally, we would be unable to obtain cash from our pipeline subsidiaries through our cash management program in an event of default under some of our subsidiaries' indentures. Finally, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

We believe we will be able to meet our ongoing liquidity and cash needs through the combination of available cash and borrowings under our $3 billion credit agreement. We also believe that the actions we have taken to date will allow us greater financial flexibility for the remainder of 2005 and into 2006 than we had in 2004. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans. These factors are discussed in detail beginning on page 83.

*Overview of Cash Flow Activities for 2004 Compared to 2003*

For the years ended December 31, 2004 and 2003, our cash flows are summarized as follows:

| | 2004 | 2003 (Restated) |
|---|---|---|
| | (In billions) | |
| **Cash inflows** | | |
| *Continuing operating activities* | | |
| Net loss before discontinued operations | $(0.8) | $(0.6) |
| Non-cash income adjustments | 2.4 | 1.8 |
| Payment on Western Energy Settlement | (0.6) | — |
| Change in assets and liabilities | 0.1 | 1.1 |
| | 1.1 | 2.3 |
| *Continuing investing activities* | | |
| Net proceeds from the sale of assets and investments | 1.9 | 2.5 |
| Net proceeds from restricted cash | 0.6 | — |
| Other | 0.1 | — |
| | 2.6 | 2.5 |
| *Continuing financing activities* | | |
| Net proceeds from the issuance of long-term debt | 1.3 | 3.6 |
| Borrowings under long-term credit facility | — | 0.5 |
| Proceeds from the issuance of common stock | 0.1 | 0.1 |
| Net discontinued operations activity | 1.0 | 0.4 |
| | 2.4 | 4.6 |
| Total cash inflows | $ 6.1 | $ 9.4 |
| **Cash outflows** | | |
| *Continuing investing activities* | | |
| Additions to property, plant, and equipment | $ 1.8 | $ 2.4 |
| Net cash paid to acquire Chaparral and Gemstone | — | 1.1 |
| Net payments of restricted cash | — | 0.5 |
| Other | — | 0.1 |
| | 1.8 | 4.1 |
| *Continuing financing activities* | | |
| Payments to retire long-term debt and redeem preferred interests | 2.5 | 4.1 |
| Payments of revolving credit facilities | 0.9 | 1.2 |
| Dividends paid to common stockholders | 0.1 | 0.2 |
| Other | 0.1 | — |
| | 3.6 | 5.5 |
| Total cash outflows | 5.4 | 9.6 |
| Net change in cash | $ 0.7 | $(0.2) |

*Cash From Continuing Operating Activities*

Overall, cash generated from continuing operating activities decreased by $1.2 billion largely due to a payment of $0.6 billion related to the principal litigation under the Western Energy Settlement in 2004 and higher cash recovered from margin deposits in 2003. We recovered $0.7 billion of cash in 2003 from our margin deposits by substituting letters of credit for cash on deposit as compared to $0.1 billion recovered in 2004.

*Cash From Continuing Investing Activities*

For the year ended December 31, 2004, net cash provided by our continuing investing activities was $0.8 billion. During the year, we received net proceeds of approximately $0.9 billion from sales of our domestic power assets as well as $1.0 billion from the sales of our general and limited partnership interests in GulfTerra and various other Field Services assets. We also released restricted cash of $0.6 billion out of escrow, which was paid to the settling parties to the Western Energy Settlement as discussed above.

Our 2004 capital expenditures included the following (in billions):

| | |
|---|---|
| Production exploration, development and acquisition expenditures | $0.7 |
| Pipeline expansion, maintenance and integrity projects | 1.0 |
| Other (primarily power projects) | 0.1 |
| Total capital expenditures and net additions to equity investments | $1.8 |

In 2005, we expect our total capital expenditures, including acquisitions, to be approximately $1.9 billion, divided approximately equally between our Production and Pipelines segments. In 2004, our Production segment received funds of approximately $110 million from third parties under net profits interest agreements. In March 2005, we purchased all of the interests held by one of the parties to these agreements for $62 million. See Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations, for a further discussion of these agreements.

In September 2004, we incurred significant damage to sections of our offshore pipeline facilities due to Hurricane Ivan. Cost estimates are currently in the $80 million to $95 million range with damage assessment still in progress. We expect insurance reimbursement with the exception of a $2 million deductible for this event; however the timing of such reimbursements may occur later than the capital expenditures on the damaged facilities which may increase our net capital expenditures for 2005.

In January 2005, we sold our remaining interests in Enterprise and its general partner for $425 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million. During 2005, we will continue to divest, where appropriate, our non-core assets based on our long-term business strategy, including additional power assets in Asia and other countries (see Part I, Item 1, Business and Part II, Item 8, Financial Statements and Supplementary Data, Note 3, for a further discussion of these divestitures and the asset divestitures of our discontinued operations). The timing and extent of these additional sales will be based on the level of market interest and based upon obtaining the necessary approvals.

*Cash From Continuing Financing Activities*

Net cash used in our continuing financing activities was $1.2 billion for the year ended December 31, 2004. During 2004, our significant financing cash inflows included $1.25 billion borrowed as a term loan under our new $3 billion credit agreement. We also had $1.0 billion of cash contributed by our discontinued operations. Of the amount contributed by our discontinued operations, $0.2 billion was generated from operations, $1.2 billion was received as proceeds from the sales of our Eagle Point and Aruba refineries and our international production operations, primarily in western Canada, and $0.4 billion was used to repay long-term debt related to the Aruba refinery.

Our significant financing cash outflows included net repayments of $0.9 billion on our previous $3 billion revolving credit facilities during 2004, prior to entering into our new $3 billion credit agreement. We also made $2.5 billion of payments to retire third party long-term debt and redeem preferred interests as we continued in our efforts to reduce our overall debt obligations under our Long-Range Plan. See Part II, Item 8, Financial Statements and Supplementary Data, Note 15, for further detail of our financing activities.

## Contractual Obligations and Off-Balance Sheet Arrangements

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. The following discusses those contingent obligations, often referred to as off-balance sheet arrangements. We also present aggregated information on our contractual cash obligations, some of which are reflected in our financial statements, such as short-term and long-term debt and other accrued liabilities; other obligations, such as operating leases; and capital commitments are not reflected in our financial statements.

### Off-Balance Sheet Arrangements and Related Liabilities

*Guarantees*

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support in the form of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to deliver natural gas to a third party and then fails to do so, we would be required to either deliver that natural gas or make payments to the third party equal to the difference between the contract price and the market value of the natural gas. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include indemnifications for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

We evaluate our guarantees and indemnity arrangements at the time they are entered into and in each period thereafter to determine whether a liability exists and, if so, if it can be estimated. We record accruals when both these criteria are met. As of December 31, 2004, we had accrued $70 million related to these arrangements. As of December 31, 2004, we also had approximately $40 million of financial and performance guarantees and indemnification arrangements not otherwise reflected in our financial statements.

### Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2004, for each of the years presented (all amounts are undiscounted):

| | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| | | | | (In millions) | | | |
| Long-term financing obligations:(1) | | | | | | | |
| Principal | $ 948 | $1,155 | $ 835 | $ 733 | $2,637 | $13,031 | $19,339 |
| Interest | 1,356 | 1,330 | 1,257 | 1,191 | 1,127 | 11,762 | 18,023 |
| Western Energy Settlement(2) | 44 | 44 | 44 | 44 | 44 | 634 | 854 |
| Other contractual liabilities(3) | 31 | 47 | 23 | 22 | 5 | 32 | 160 |
| Operating leases(4) | 79 | 66 | 51 | 43 | 40 | 163 | 442 |
| Other contractual commitments and purchase obligations:(5) | | | | | | | |
| Tolling, transportation and storage(6) | 178 | 144 | 131 | 127 | 122 | 779 | 1,481 |
| Commodity purchases(7) | 30 | 28 | 28 | 17 | 10 | 36 | 149 |
| Other(8) | 151 | 36 | 14 | 15 | 5 | 3 | 224 |
| Total contractual obligations | $2,817 | $2,850 | $2,383 | $2,192 | $3,990 | $26, 440 | $40,672 |

(1) See Part II, Item 8, Financial Statements and Supplementary Data, Note 15.

(2) See Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

(3) Includes contractual, environmental and other obligations included in other noncurrent liabilities in our balance sheet. Excludes expected contributions to our pension and other postretirement benefit plans of $68 million in 2005 and $209 million for the four year period ended December 31, 2009, because these expected contributions are not contractually required.

(4) See Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

(5) Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations.

(6) These are commitments for demand charges on our tolling arrangements and for firm access to natural gas transportation and storage capacity.

(7) Includes purchase commitments for natural gas and power.

(8) Includes commitments for drilling and seismic activities in our production operations and various other maintenance, engineering, procurement and construction contracts, as well as service and license agreements, used by our other operations.

## Commodity-based Derivative Contracts

We utilize derivative financial instruments in hedging activities, power contract restructuring activities and in our historical energy trading activities. In the tables below, derivatives designated as hedges primarily consist of instruments used to hedge natural gas production. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities as well as other derivative contracts not designated as hedges.

The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2004:

| Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity 6 to 10 Years | Maturity Beyond 10 Years | Total Fair Value |
|---|---|---|---|---|---|---|
| | | | (In millions) | | | |
| Derivatives designated as hedges | | | | | | |
| Assets | $ 92 | $ 33 | $ — | $ — | $ — | $ 125 |
| Liabilities | (416) | (222) | (14) | (9) | — | (661) |
| Total derivatives designated as hedges | (324) | (189) | (14) | (9) | — | (536) |
| Assets from power contract restructuring derivatives(1)(2) | 105 | 199 | 151 | 210 | — | 665 |
| Other commodity-based derivatives | | | | | | |
| Exchange-traded positions(3) | | | | | | |
| Assets | 19 | 220 | 76 | — | — | 315 |
| Liabilities | (107) | (1) | — | — | — | (108) |
| Non-exchange traded positions(2) | | | | | | |
| Assets | 431 | 271 | 186 | 166 | 46 | 1,100 |
| Liabilities(1) | (372) | (448) | (267) | (230) | (51) | (1,368) |
| Total other commodity-based derivatives | (29) | 42 | (5) | (64) | (5) | (61) |
| Total commodity-based derivatives | $(248) | $ 52 | $ 132 | $ 137 | $ (5) | $ 68 |

(1) Includes $259 million of intercompany derivatives that eliminate in consolidation and have no impact on our consolidated assets and liabilities from price risk management activities.

(2) In March 2005, we sold our Cedar Brakes I and II subsidiaries and their related restructured power contracts, which had a fair value of $596 million as of December 31, 2004. In connection with this sale, we also assigned or terminated other commodity-based derivatives that had a fair value loss of $240 million as of December 31, 2004.

(3) Exchange-traded positions are traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London Clearinghouse.

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2004 and 2003.

| | Derivatives Designated as Hedges | Derivatives from Power Contract Restructuring Activities | Other Commodity-Based Derivatives | Total Commodity-Based Derivatives |
|---|---|---|---|---|
| | | (In millions) | | |
| Fair value of contracts outstanding at December 31, 2002 | $ (21) | $ 968 | $(525) | $ 422 |
| Fair value of contract settlements during the period | 15 | (405) | 602 | 212 |
| Change in fair value of contracts | (25) | 140 | (477) | (362) |
| Original fair value of contracts consolidated as a result of Chaparral acquisition | — | 1,222 | — | 1,222 |
| Option premiums received, net | — | — | (88) | (88) |
| Net change in contracts outstanding during the period | (10) | 957 | 37 | 984 |
| Fair value of contracts outstanding at December 31, 2003 | (31) | 1,925 | (488) | 1,406 |
| Fair value of contract settlements during the period | 49 | (1,132) [1] | 284 | (799) |
| Change in fair value of contracts | 38 | (128) [2] | (513) [3] | (603) |
| Other commodity-based derivatives designated as hedges | (592) | — | 592 | — |
| Option premiums paid, net | — | — | 64 | 64 |
| Net change in contracts outstanding during the period | (505) | (1,260) | 427 | (1,338) |
| Fair value of contracts outstanding at December 31, 2004 | $(536) | $ 665 | $ (61) | $ 68 |

(1) Includes $861 million and $75 million of derivative contracts sold in conjunction with the sales of Utility Contract Funding and Mohawk River Funding IV in 2004. See Part II, Item 8, Financial Statements, Notes 3 and 5 for additional information on these sales.

(2) In the fourth quarter of 2004, we recorded a $227 million charge associated with the sale of our Cedar Brakes I and II subsidiaries and their related restructured power contracts. See Part II, Item 8, Financial Statements and Supplementary Data, Notes 3 and 5 for additional information on this sale.

(3) In the second quarter of 2004, we reclassified a $69 million liability from our Western Energy Settlement obligation to our price risk management activities.

The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement, early termination or, if not settled or terminated, until the end of the period. During 2003, in conjunction with our acquisition of Chaparral, we consolidated a number of derivative contracts. The majority of the value of these contracts was for power purchase agreements and power supply agreements related to power contract restructuring activities conducted by Chaparral.

In December 2004, we designated a number of our other commodity-based derivative contracts in our Marketing and Trading segment as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004. The combination of these positions and our Production segment's other hedges will result in us receiving the following prices on our natural gas production:

| | Volume (TBtu) | Hedge Price[1] (per MMBtu) | Cash Price (per MMBtu) |
|---|---|---|---|
| 2005 | 132 | $6.75 | $3.74[2] |
| 2006 | 86 | $6.34 | $4.01[2] |
| 2007 | 5 | $3.56 | $3.56 |
| 2008 to 2012 | 21 | $3.67 | $3.67 |

(1) Our Production segment will record revenues related to these natural gas volumes at this price in their operating results.

(2) The difference between our Production segment's hedge price and the cash price we will receive upon settlement of the derivative transactions was previously recorded as losses in our Marketing and Trading segment.

To stabilize the company's pricing outlook for 2005 to 2007, our Marketing and Trading segment entered into additional contracts that provide a floor price on a portion of our unhedged production in 2005, 2006 and 2007 and a ceiling price on a portion of our unhedged 2006 production. These contracts, which are reported on a mark-to-market basis, will result in us receiving the following cash prices on our natural gas production:

| | Floor Price[1] (per MMBtu) | Floor Volume (TBtu) | Ceiling Price[2] (per MMBtu) | Ceiling Volume (TBtu) |
|---|---|---|---|---|
| 2005 | $6.00 | 60 | — | — |
| 2006 | $6.00 | 120 | $9.50 | 60 |
| 2007 | $6.00 | 30 | — | — |

(1) The floor price is the minimum cash price to be received under the option contract.

(2) The ceiling price is the maximum cash price to be received under the option contract.

## Results of Operations

### Overview

Since 2001, we have experienced tremendous change in our businesses. Prior to this time, we had grown through mergers and acquisitions and internal growth initiatives, and at the same time had incurred significant amounts of debt and other obligations. In late 2001, driven by the bankruptcy of a number of energy sector participants, followed by increased scrutiny of our debt levels and credit rating downgrades of our debt and the debt of many of our competitors, our focus changed to improving liquidity, paying down debt, simplifying our capital structure, reducing our cost of capital, resolving substantial contingences and returning to our core natural gas businesses. Accordingly, our operating results during the three year period from 2002 to 2004 have been substantially impacted by a number of significant events, such as asset sales, significant legal settlements and ongoing business restructuring efforts as part of this change in focus.

As of December 31, 2004, our operating business segments were Pipelines, Production, Marketing and Trading, Power and Field Services. These segments provide a variety of energy products and services. They are managed separately and each requires different technology and marketing strategies. Our businesses are divided into two primary business lines: regulated and non-regulated. Our regulated business includes our Pipelines segment, while our non-regulated business includes our Production, Marketing and Trading, Power and Field Services segments.

Our management uses EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our businesses consist of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results independently from our financing methods or capital structure. We believe EBIT is helpful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

Below is a reconciliation of our EBIT (by segment) to our consolidated net loss for each of the three years ended December 31:

| | 2004 | 2003 (Restated)[1] | 2002 (Restated)[1] |
|---|---|---|---|
| | | (In millions) | |
| *Regulated Business* | | | |
| Pipelines | $ 1,331 | $ 1,234 | $ 828 |
| *Non-regulated Businesses* | | | |
| Production | 734 | 1,091 | 808 |
| Marketing and Trading | (547) | (809) | (1,977) |
| Power | (569) | (28) | 12 |
| Field Services | 120 | 133 | 289 |
| Segment EBIT | 1,069 | 1,621 | (40) |
| *Corporate and other* | (214) | (852) | (387) |
| Consolidated EBIT | 855 | 769 | (427) |
| Interest and debt expense | (1,607) | (1,791) | (1,297) |
| Distributions on preferred interests of consolidated subsidiaries | (25) | (52) | (159) |
| Income taxes | (25) | 469 | 641 |
| Loss from continuing operations | (802) | (605) | (1,242) |
| Discontinued operations, net of income taxes | (146) | (1,314) | (425) |
| Cumulative effect of accounting changes, net of income taxes | — | (9) | (208) |
| Net loss | $ (948) | $(1,928) | $(1,875) |

[1] See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a discussion of the restatements of our 2002 and 2003 financial statements. The restatement of our 2002 financial statements affected our Pipelines segment results and the amounts reported as a cumulative effect of accounting change in 2002. The restatement of our 2003 financial statements affected the classification of income taxes between continuing and discontinued operations, and therefore the results reported as continuing versus discontinued for that period.

As we refocused our activities on our core businesses by divesting of non-core businesses and restructuring our organization, we incurred losses and incremental costs in each year. During this period, we also resolved significant legal contingencies. These items are described in the table below. For a more detailed discussion of these factors and other items impacting our financial performance, see the individual segment and other results included in Part II, Item 8, Financial Statements and Supplementary Data, Notes 3 through 5, and 21.

| | Operating Segments | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Production | Marketing and Trading | Power | Field Services | Corporate & Other |
| | (In millions) | | | | | |
| ***2004*** | | | | | | |
| Asset and investment impairments, net of gain(loss) on sales[1] | $ 20 | $ (8) | $ — | $(973) | $ (7)[2] | $ 3 |
| Restructuring charges | (5) | (14) | (2) | (5) | (1) | (91) |
| Total | $ 15 | $(22) | $ (2) | $(978) | $ (8) | $ (8 8) |
| ***2003*** | | | | | | |
| Asset and investment impairments, net of gain(loss) on sales[1] | $ 9 | $ (5) | $ 3 | $(525) | $ 9 | $(525) |
| Ceiling test charges | — | (5) | | — | — | — |
| Restructuring charges | (2) | (6) | (16) | (5) | (4) | (91) |
| Western Energy Settlement[3] | (140) | — | (26) | — | — | (4) |
| Total | $(133) | $(16) | (39) | (530) | $ 5 | $(620) |
| ***2002*** (Restated) | | | | | | |
| Asset and investment impairments, net of gain(loss) on sales[1] | $(125) | $ 1 | $ — | $(642) | $129 | $(212) |
| Ceiling test charges | — | (5) | — | — | — | — |
| Restructuring charges | (1) | — | (10) | (14) | (1) | (51) |
| Western Energy Settlement | (412) | — | (487) | — | — | — |
| Net gain on power contract restructurings[4] | — | — | — | 578 | — | — |
| Total | $(538) | $ (4) | $(497) | $ (78) | $128 | $(263) |

(1) Includes net impairments of cost-based investments included in other income and expense.

(2) Includes the gain on our transactions with Enterprise and a goodwill impairment.

(3) Includes $66 million of accretion expense and other charges included in operation and maintenance expense associated with the Western Energy Settlement.

(4) Excludes intercompany transactions related to the UCF restructuring transaction which were eliminated in consolidation.

In our Pipelines segment, we experienced improved financial performance from 2002 to 2004, benefitting from the completion of a number of expansion projects and from the resolution of significant legal issues related to the western energy crisis of 2001.

In our Production segment, we have experienced earnings volatility from 2002 to 2004. During this three-year period, our Production segment sold a significant number of natural gas and oil properties which, coupled with a reduced capital spending program, generally disappointing drilling results and mechanical failures on certain wells, produced a steady decline in production volumes during that timeframe. However, in 2004, we benefited from a favorable pricing environment that allowed for better than anticipated results. The favorable pricing environment is expected to continue to provide benefits to the Production segment during 2005, although its future results will largely be impacted by our production levels. The volumes we produce will be driven by our ability to grow the existing reserve base through a successful drilling program and/or acquisitions.

In our Marketing and Trading segment, we also experienced significant earnings volatility during 2002, 2003 and 2004. Beginning in 2002, we began a process of exiting the trading business. At the same time, the overall energy trading industry has declined. The combination of these actions and events and a decrease in the value of our fixed-price natural gas derivative contracts due to natural gas price increases resulted in substantial losses in our Marketing and Trading segment in 2002, 2003 and 2004. We expect that this segment will continue to experience losses in 2005 as it continues performing under its transportation and tolling contracts. However, due to the repositioning of a number of our natural gas derivative contracts as hedges in December 2004, we expect future losses in this segment to be less than those experienced in 2002 through 2004.

Finally, during 2002 through 2004, as we continued to refocus and restructure our company around our core businesses, we incurred significant charges related to asset sales, impairments and other restructuring costs in our Field Services and Power segments as well as in our corporate results. We also incurred approximately $2.0 billion (including $1.4 billion during 2003) in after tax losses in exiting certain of our international natural gas and oil production operations and our petroleum markets and coal businesses, which are classified as discontinued operations.

Below is a further discussion of the year over year results of each of our business segments, our corporate activities and other income statement items.

## Individual Segment Results

The results for 2002 of our Pipelines segment presented and discussed below have been restated for errors resulting from a misinterpretation of the provisions of SFAS Nos. 141 and 142 upon the adoption of these standards. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatement.

### Regulated Business — Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage, LNG terminalling and related services, primarily in the United States. We face varying degrees of competition in this segment from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the cost of providing services to our customers, including a reasonable return on our invested capital. As a result, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather. In 2004, 84 percent of our transportation service, storage and LNG terminalling revenues were attributable to reservation charges paid by firm customers. The remaining 16 percent of our revenues are variable. We also experience earnings volatility when the amount of natural gas utilized in operations differs from the amounts we receive for that purpose.

Historically, much of our business was conducted through long-term contracts with customers. However, over the past several years some of our customers have shifted from a traditional dependence solely on long-term contracts to a portfolio approach which balances short-term opportunities with long-term commitments. This shift, which can increase the volatility of our revenues, is due to changes in market conditions and competition driven by state utility deregulation, local distribution company mergers, new supply sources, volatility in natural gas prices, demand for short-term capacity and new power plants markets.

In addition, our ability to extend existing customer contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although, at times, we discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2004. Below is the expiration schedule for contracts executed as of December 31, 2004, including those whose terms begin in 2005 or later.

| | MDth/d | Percent of Total Contracted Capacity |
|---|---|---|
| 2005 | 3,838 | 13 |
| 2006[(1)(2)] | 6,414 | 21 |
| 2007 | 4,539 | 15 |
| 2008 and beyond | 15,540 | 51 |

(1) Reflects the impact of an agreement, that we entered into to extend 750 MMcf/d of SoCal's current capacity, effective September 1, 2006, for terms of three to five years. The agreement is subject to FERC approval.

(2) Includes approximately 1,564 MMcf/d currently under contract on EPNG's system through 2011 and beyond that is subject to early termination in August 2006 provided customers give timely notice of an intent to terminate.

*Operating Results*

Below are the operating results and analysis of these results for our Pipelines segment for each of the three years ended December 31:

| Pipelines Segment Results | 2004 | 2003 | 2002 (Restated) |
|---|---|---|---|
| | (In millions, except volume amounts) | | |
| Operating revenues | $ 2,651 | $ 2,647 | $ 2,610 |
| Operating expenses | (1,522) | (1,584) | (1,822) |
| Operating income | 1,129 | 1,063 | 788 |
| Other income | 202 | 171 | 40 |
| EBIT | $ 1,331 | $ 1,234 | $ 828 |
| Throughput volumes (BBtu/d)[(1)] | | | |
| TGP | 4,519 | 4,760 | 4,610 |
| EPNG and MPC | 4,235 | 4,066 | 4,065 |
| ANR | 4,067 | 4,232 | 4,130 |
| CIG, WIC and CPG | 2,795 | 2,743 | 2,768 |
| SNG | 2,163 | 2,101 | 2,151 |
| Equity investments (our ownership share) | 2,798 | 2,433 | 2,408 |
| Total throughput | 20,577 | 20,335 | 20,132 |

(1) Throughput volumes exclude volumes related to our equity investments in Portland Natural Gas Transmission System, EPIC Energy Australia Trust and Alliance Pipeline, which have been sold. In addition, volumes exclude intrasegment activities. Throughput volumes include volumes related to our Mexico investments which were transferred from our Power segment effective January 1, 2004.

The following contributed to our overall EBIT increases in 2004 as compared to 2003 and in 2003 as compared to 2002:

| | 2004 to 2003 | | | | 2003 to 2002 | | | |
|---|---|---|---|---|---|---|---|---|
| | Revenue | Expense | Other | EBIT Impact | Revenue | Expense | Other | EBIT Impact |
| | Favorable/(Unfavorable) (In millions) | | | | Favorable/(Unfavorable) (In millions) | | | |
| Contract modifications/terminations | $(93) | $ 37 | — | $(56) | $(52) | $ (7) | — | $(59) |
| Gas not used in operations and other natural gas sales | 67 | (16) | — | 51 | 57 | (18) | — | 39 |
| Mainline expansions | 33 | (6) | (6) | 21 | 47 | (7) | 3 | 43 |
| Sale of Panhandle fields and other production properties in 2002 | — | — | — | — | (50) | 21 | — | (29) |
| Operation and maintenance costs[1] | — | (69) | — | (69) | — | 9 | — | 9 |
| Other regulatory matters | — | (9) | (19) | (28) | — | — | 18 | 18 |
| Equity earnings from Citrus | — | — | 22 | 22 | — | — | — | — |
| Mexico investments | 9 | (6) | 17 | 20 | — | — | — | — |
| Australia investment impairment | — | — | — | — | — | — | 141 | 141 |
| Western Energy Settlement | — | 140 | — | 140 | — | 272 | — | 272 |
| Other[2] | (12) | (9) | 17 | (4) | 35 | (32) | (31) | (28) |
| Total impact on EBIT | $ 4 | $ 62 | $ 31 | $ 97 | $ 37 | $238 | $131 | $406 |

(1) Consists of costs of operations, electric and power purchase costs, shared services allocations and environmental costs.

(2) Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

*Contract Modifications/Terminations.* Included in this item are (i) the impacts of the expiration of EPNG's historical risk sharing provisions which reduced revenues by $24 million in 2004 (ii) the impact of EPNG's FERC ordered restrictions on remarketing expiring capacity contracts which reduced EPNG's 2003 revenues by $35 million compared to 2002 (iii) the renegotiation or restructuring of several contracts on our pipeline systems, including ANR's contracts with We Energies which contributed to the decrease in revenues by $36 million in 2004 and $12 million in 2003, and (iv) the termination of the Dakota gasification facility contract on ANR's system, which resulted in lower operating revenues and lower operating expenses during 2004, without a significant overall impact on operating income and EBIT.

During 2003, EPNG was prohibited from remarketing expiring capacity contracts due to certain FERC orders. While these capacity restrictions terminated with the completion of Phases I and II of EPNG's Line 2000 Power-up project in 2004, EPNG remains at risk for that portion of capacity which was turned back to it on a permanently released basis. EPNG is able, however, to re-market that capacity subject to the general requirement that it demonstrate that any sale of capacity does not adversely impact its service to its firm customers.

EPNG has entered into an agreement effective September 1, 2006, to extend 750 MMcf/d of capacity on its pipeline system with SoCalGas. The new service agreements will have a primary term of three to five years to serve SoCalGas' core customers. SoCalGas is currently contracted on EPNG's system for approximately 1.3 Bcf/d of capacity. EPNG continues in its efforts to market the remaining capacity, including marketing efforts to serve, directly or indirectly, SoCalGas' non-core customers or to serve new markets. At this time, we are uncertain whether this remaining capacity will be re-contracted.

Guardian Pipeline, which is owned in part by We Energies, currently provides a portion of We Energies' firm transportation requirements and, therefore, directly competes with ANR for a portion of the markets in Wisconsin. This could impact ANR's existing customer contracts as well as future contractual negotiations with We Energies. In addition, ANR has entered into an agreement with a shipper to restructure one of its transportation contracts on its Southeast Leg as well as a related gathering contract. In March 2005, this restructuring was completed and ANR received approximately $26 million, which will be included in its earnings during the first quarter of 2005.

*Gas Not Used in Operations and Other Natural Gas Sales.* For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to the applicable tariff, relative to the amounts of gas we use for operating purposes, and the price of natural gas. The disposition of gas not needed for operations results in revenues to us, which are driven by volumes and prices during the period. During 2003 and 2004, we recovered, fairly consistently, volumes of natural gas that were not utilized for operations for some of our regulated pipeline systems. These recoveries were and are based on factors such as system throughput, facility enhancements and the ability to operate the systems in the most efficient and safe manner. Additionally, a steadily increasing natural gas price environment during this timeframe also resulted in favorable impacts on our operating results in both 2004 versus 2003 and in 2003 versus 2002. We anticipate that this area of our business will continue to vary in the future and will be impacted by things such as rate actions, some of which have already been implemented, efficiency of our pipeline operations, natural gas prices and other factors.

*Expansions.* During the three years ended December 31, 2004, we completed a number of expansion projects that have generated or will generate new sources of revenues the more significant of which were our ANR WestLeg Expansion, SNG South System Expansions, TGP South Texas Expansion and CIG Front Range Expansion. Our expansions during this three year period added approximately 1,968 MMcf/d to our overall pipeline system.

Our pipeline systems connect the principal gas supply regions to the largest consuming regions in the U.S. We are well-positioned to capture growth opportunities in the Rocky Mountains and deepwater Gulf of Mexico, and have an infrastructure that complements LNG growth. We are aggressively seeking to attach new supplies of natural gas to our systems in order to maintain an adequate supply of gas to serve our growing markets and to replace quantities lost due to the natural decline in production from wells currently attached to our system.

Expansion projects currently in process include:

*Rocky Mountain Expansions.* In order to provide an outlet for the growing supply of Rocky Mountain natural gas to markets in the Midwest region of the United States, we have several expansion projects that will increase our transportation capacity, subject to regulatory approval as follows:

- Cheyenne Plains Gas Pipeline commenced free-flow operations in December 2004 and as of January 31, 2005 is fully in-service. Approval has already been received for Cheyenne Plains Phase II which will add an additional 179 MMcf/d of capacity that is scheduled to be available by the end of 2005.
- CIG's Raton Basin 2005 Expansion will add 104 MMcf/d of capacity that is scheduled to be available by the end of 2005.
- WIC expects to complete its Piceance lateral with capacity of 333 MMcf/d by the end of 2005.
- EPNG's Line 1903 project, consisting of an expansion from Cadiz, California to Ehrenberg, Arizona, that is expected to be in-service by end of 2005 and will increase its capacity by 372 MMcf/d.

*LNG Related Expansions and Other.* In order to help serve the growing electrical generation needs in the state of Florida, we (i) have commenced a 3.5 Bcf expansion at our Elba Island LNG facility, which is targeted to be completed in the first quarter of 2006, (ii) have begun developing our Cypress Project, which will transport these additional supplies into the Florida market, and (iii) have filed an application with the FERC for authority to construct and operate the U.S. portion of the proposed Seafarer natural gas pipeline, which will transport natural gas from an LNG facility in the Bahamas to southern Florida.

On our TGP and ANR systems, we continue to experience intense competition along their mainline corridors; however, both are well-positioned to provide transportation service from discoveries in the deepwater Gulf of Mexico and LNG supply growth along the Gulf Coast. These new supplies are expected to offset the continued decline of production from the Gulf of Mexico shelf. Additionally, TGP is developing its ConneXion Expansions in the Northeast market area and ANR is proceeding with its Eastleg and Northleg expansions in its Wisconsin market area.

*Other Regulatory Matters.* In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $25 million to $41 million annually over the next eight years.

In 2003, we re-applied Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, on our CIG and WIC systems, resulting in income from recording the regulatory assets of these systems. SFAS No. 71 allows a company to capitalize items that will be considered in future rate proceedings and $18 million in income resulted from the capitalization of those items that we believe will be considered in CIG's and WIC's future rate cases. At the same time CIG and WIC re-applied SFAS No. 71, they adopted the FERC depreciation rate for their regulated plant and equipment. This change resulted in an increase in depreciation expense of approximately $9 million in 2004, an increase which will continue in the future. As of December 31, 2004, ANR Storage Company re-applied SFAS No. 71 which had an immaterial impact and also adopted the FERC depreciation rate which will result in future depreciation expense increases of approximately $4 million annually.

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability. Listed below is a status of our rate proceedings:

- SNG — filed a rate case in August 2004; settlement discussions with major customers are underway with a settlement conference to be scheduled in early 2005.
- EPNG — expected to file for new rates that would be effective January 2006.
- CIG — required to file for new rates that would be effective October 2006.
- MPC — expected to file for new rates that would be effective February 2007.

Our other pipelines have no requirements to file new rate cases and expect to continue operating under their existing rates.

*Australian Impairment.* In 2002, our impairment of EPIC Energy Australia Trust of $141 million occurred due to an unfavorable regulatory environment, increased competition and operational complexities in Australia. During the second quarter of 2004, we substantially exited our investments in Australian operations.

*Western Energy Settlement.* In 2003, El Paso entered into the Western Energy Settlement. EPNG was a party to that settlement and recorded a charge in its 2002 operating expenses of $412 million for its share of the expected settlement amounts. This charge represented the value of El Paso stock and cash that EPNG paid to the settling parties. In the second quarter of 2003, the settlement was finalized and EPNG recorded an additional net pretax charge of $127 million. Also during 2003, accretion expense and other miscellaneous charges of $13 million were recorded and included in operating expenses.

**Non-regulated Business — Production Segment**

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the 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 minimize our total administrative costs.

Our long-term strategy includes developing our production opportunities primarily in the United States and Brazil, while prudently divesting of production properties outside of these regions. We emphasize strict capital discipline designed to improve capital efficiencies through the use of standardized risk analysis and a heightened focus on cost control. We also implemented a more rigorous process for booking proved natural gas and oil reserves, which includes multiple layers of reviews by personnel independent of the reserve estimation process. Our plan is to stabilize production by improving the production mix across our operating areas and to generate more predictable returns. We intend to improve our production mix by allocating more capital to long-life, slower decline projects and to develop projects in longer reserve life areas. This is being accomplished through our more rigorous capital review process and a more balanced allocation of our capital to development and exploration projects, supplemented by acquisition activities with low-risk development locations that provide operating synergies with our existing operations. In January 2005, we announced two acquisitions in east Texas and south Texas for $211 million. In March 2005, we acquired the interests held by one of the parties under our net profits interest agreements for $62 million. See Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations for a further discussion of these net profits interest agreements. These acquisitions added properties with approximately 139 Bcfe of existing proved reserves and 52 MMcfe/d of current production. More importantly, the Texas acquisitions offer additional exploration upside in two of our key operating areas.

*Reserves, Production and Costs*

Our estimate of proved natural gas and oil reserves as of December 31, 2004 reflects 2.0 Tcfe of proved reserves in the United States and 0.2 Tcfe of proved reserves in Brazil. These estimates were prepared internally by us. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott is within four percent of our internally prepared estimates. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our properties based on value. For additional information on our estimated proved reserves and the processes by which they are developed, see Part I, Item 1, Business, Non- regulated Business — Production Segment, Part I, Item 7, Critical Accounting Policies and Risk Factors, and Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

For 2004, our total equivalent production declined 112 Bcfe or 27 percent as compared to 2003. The decrease was due to steep production declines in our Texas Gulf Coast and offshore Gulf of Mexico regions, the sale of properties in Oklahoma and New Mexico at the end of the first quarter of 2003, and a significantly reduced capital expenditure program in 2004 compared to 2003. We began to see our production stabilize in the third and fourth quarters of 2004 as we instituted our more rigorous capital review process and a more balanced allocation of our capital described above. Our depletion rate is determined under the full cost method of accounting. Due to disappointing drilling performance in 2004 that resulted in higher finding and development costs, we expect our domestic unit of production depletion rate to increase from $1.80/Mcfe in the fourth quarter of 2004 to $1.97/Mcfe in the first quarter of 2005. Our future trends in production and depletion rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sale or acquisition activities relating to our proved reserves.

*Production Hedge Position*

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment programs. We conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production. Because this hedging strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. For 2005, we expect to have hedged approximately 50 percent of our anticipated daily natural gas production and approximately 8 percent of our anticipated daily oil production. Below are the hedging positions on our anticipated natural gas and oil production as of December 31, 2004:

*Natural Gas*

| | Quarter Ended | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | March 31 | | June 30 | | September 30 | | December 31 | | Total | |
| | Volume (BBtu) | Hedged Price (per MMBtu) | Volume (BBtu) | Hedged Price (per MMBtu) | Volume (BBtu) | Hedged Price (per MMBtu) | Volume (BBtu) | Hedged Price (per MMBtu) | Volume (BBtu) | Hedged Price (per MMBtu) |
| 2005 | 33,019 | $7.26 | 33,037 | $6.47 | 33,055 | $6.49 | 33,055 | $6.77 | 132,166 | $6.75 |
| 2006 | 21,349 | $7.07 | 21,367 | $6.01 | 21,385 | $6.01 | 21,385 | $6.28 | 85,486 | $6.34 |
| 2007 | 1,579 | $3.79 | 1,447 | $3.64 | 1,155 | $3.35 | 1,155 | $3.35 | 5,336 | $3.56 |
| 2008 through 2012 | | | | | | | | | 20,620 | $3.67 |

*Oil*

| | Quarter Ended | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | March 31 | | June 30 | | September 30 | | December 31 | | Total | |
| | Volume (MBbls) | Hedged Price (per Bbl) | Volume (MBbls) | Hedged Price (per Bbl) | Volume (MBbls) | Hedged Price (per Bbl) | Volume (MBbls) | Hedged Price (per Bbl) | Volume (MBbls) | Hedged Price (per Bbl) |
| 2005 | 94 | $35.15 | 96 | $35.15 | 96 | $35.15 | 97 | $35.15 | 383 | $35.15 |
| 2006 | 94 | $35.15 | 96 | $35.15 | 96 | $35.15 | 97 | $35.15 | 383 | $35.15 |
| 2007 | 47 | $35.15 | 48 | $35.15 | 48 | $35.15 | 49 | $35.15 | 192 | $35.15 |

The hedged natural gas prices listed above for 2005 and 2006 include the impact of designating trading contracts in our Marketing and Trading segment as hedges of our anticipated natural gas production on December 1, 2004. For a summary of the overall cash price El Paso will receive on natural gas production including the effect of these contracts, see Commodity-based Derivative Contracts beginning on page 38.

*Operational Factors Affecting the Year Ended December 31, 2004*

During 2004, our Production segment experienced the following:

- *Higher realized prices.* Realized natural gas prices, which include the impact of our hedges, increased eight percent and oil, condensate and NGL prices increased 33 percent compared to 2003.

- *Average daily production of 814 MMcfe/d (excluding discontinued Canadian and other international operations of 15 MMcfe/d).* We achieved the low end of our projected production volume despite the impact of hurricanes in the Gulf of Mexico.

- *Capital expenditures and acquisitions of $790 million (excluding discontinued Canadian and other international expenditures of $29 million).* During the first quarter of 2004, we experienced disappointing drilling results. As a result, we significantly reduced our drilling activities and instituted a new, more rigorous, risk analysis program, with an emphasis on strict capital discipline. After implementing this new program, we increased our domestic drilling activities in the third and fourth quarters of 2004 with improved drilling results. During 2004, we drilled 325 wells with a 96 percent success rate. We also acquired the remaining 50 percent interest in UnoPaso in Brazil in July 2004. This acquisition has performed above expectations in the fourth quarter of 2004.

- *Sale of Canadian and other international operations.* These operations were sold in order to focus our operations in the United States and Brazil.

*Operating Results*

Below are our Production segment's operating results and analysis of these results for each of the three years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| Operating Revenues: | | | |
| Natural gas | $ 1,428 | $ 1,831 | $ 1,574 |
| Oil, condensate and NGL | 305 | 305 | 350 |
| Other | 2 | 5 | 7 |
| Total operating revenues | 1,735 | 2,141 | 1,931 |
| Transportation and net product costs | (54) | (82) | (109) |
| Total operating margin | 1,681 | 2,059 | 1,822 |
| Depreciation, depletion and amortization | (548) | (576) | (601) |
| Production costs(1) | (210) | (229) | (285) |
| Ceiling test and other charges(2) | (22) | (16) | (4) |
| General and administrative expenses | (173) | (160) | (122) |
| Taxes, other than production and income | (2) | (5) | (7) |
| Total operating expenses(3) | (955) | (986) | (1,019) |
| Operating income | 726 | 1,073 | 803 |
| Other income | 8 | 18 | 5 |
| EBIT | $ 734 | $ 1,091 | $ 808 |

| | 2004 | Percent Variance | 2003 | Percent Variance | 2002 |
|---|---|---|---|---|---|
| Volumes, prices and costs per unit: | | | | | |
| Natural gas | | | | | |
| Volumes (MMcf) | 244,857 | (28)% | 338,762 | (28)% | 470,082 |
| Average realized prices including hedges ($/Mcf)(4) | $ 5.83 | 8% | $ 5.40 | 61% | $ 3.35 |
| Average realized prices excluding hedges ($/Mcf)(4) | $ 5.90 | 7% | $ 5.51 | 74% | $ 3.17 |
| Average transportation costs ($/Mcf) | $ 0.17 | (6)% | $ 0.18 | — | $ 0.18 |
| Oil, condensate and NGL | | | | | |
| Volumes (MBbls) | 8,818 | (25)% | 11,778 | (28)% | 16,462 |
| Average realized prices including hedges ($/Bbl)(4) | $ 34.61 | 33% | $ 25.96 | 22% | $ 21.28 |
| Average realized prices excluding hedges ($/Bbl)(4) | $ 34.75 | 30% | $ 26.64 | 25% | $ 21.38 |
| Average transportation costs ($/Bbl) | $ 1.12 | 7% | $ 1.05 | 8% | $ 0.97 |
| Total equivalent volumes (MMcfe) | 297,766 | (27)% | 409,432 | (28)% | 568,852 |
| Production costs ($/Mcfe) | | | | | |
| Average lease operating costs | $ 0.60 | 43% | $ 0.42 | — | $ 0.42 |
| Average production taxes | 0.11 | (21)% | 0.14 | 75% | 0.08 |
| Total production cost(1) | $ 0.71 | 27% | $ 0.56 | 12% | $ 0.50 |
| Average general and administrative expenses ($/Mcfe) | $ 0.58 | 49% | $ 0.39 | 86% | $ 0.21 |
| Unit of production depletion cost ($/Mcfe) | $ 1.69 | 29% | $ 1.31 | 28% | $ 1.02 |

(1) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).
(2) Includes ceiling test charges, restructuring charges, asset impairments and gains on asset sales.
(3) Transportation costs are included in operating expenses on our consolidated statements of income.

(4) Prices are stated before transportation costs.

*Year Ended December 31, 2004 Compared to Year Ended December 31, 2003*

Our EBIT for 2004 decreased $357 million as compared to 2003. Despite an eight percent increase in natural gas prices including hedges, we experienced a significant decrease in operating revenues due to lower production volumes as a result of normal production declines, asset sales, a lower capital spending program and disappointing drilling results. The table below lists the significant variances in our operating results in 2004 as compared to 2003:

| | Variance | | | |
|---|---|---|---|---|
| | Operating Revenue | Operating Expense | Other(1) | EBIT Impact |
| | Favorable/(Unfavorable) (In millions) | | | |
| *Natural Gas Revenue* | | | | |
| Higher prices in 2004 | $ 96 | $ — | $— | $ 96 |
| Lower production volumes in 2004 | (518) | — | — | (518) |
| Impact from hedge program in 2004 versus 2003 | 19 | — | — | 19 |
| *Oil, Condensate and NGL Revenue* | | | | |
| Higher realized prices in 2004 | 72 | — | — | 72 |
| Lower production volumes in 2004 | (79) | — | — | (79) |
| Impact from hedge program in 2004 versus 2003 | 7 | — | — | 7 |
| *Depreciation, Depletion and Amortization Expense* | | | | |
| Higher depletion rate in 2004 | — | (115) | — | (115) |
| Lower production volumes in 2004 | — | 146 | — | 146 |
| *Production Costs* | | | | |
| Higher lease operating costs in 2004 | — | (8) | — | (8) |
| Lower production taxes in 2004 | — | 27 | — | 27 |
| *Other* | | | | |
| Higher general and administrative expenses in 2004 | — | (13) | — | (13) |
| Other | (3) | (6) | 18 | 9 |
| *Total variance 2004 to 2003* | $(406) | $ 31 | $18 | $(357) |

(1) Consists primarily of changes in transportation costs and other income.

*Operating revenues.* In 2004, we experienced a significant decrease in production volumes. The decline in our production volumes was due to normal production declines in the Offshore Gulf of Mexico and Texas Gulf Coast regions, asset sales, the impact of hurricanes in the Gulf of Mexico, lower capital expenditures and disappointing drilling results. These declines were partially offset by increased natural gas production in our coal seam operations in the Raton, Arkoma, and Black Warrior basins. We also had increased oil production in Brazil as a result of our acquisition of the remaining interest in UnoPaso in July 2004. In addition, we experienced higher average realized prices for natural gas and oil, condensate and NGL and a favorable impact from our hedging program as our hedging losses were $18 million in 2004 as compared to $44 million in 2003.

*Depreciation, depletion, and amortization expense.* Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs.

*Production costs.* In 2004, we experienced higher workover costs due to the implementation of programs in the second half of 2004 to improve production in the Offshore Gulf of Mexico and Texas Gulf Coast regions. We also incurred higher utility expenses and higher salt water disposal costs in the Onshore region. More than offsetting these increases were lower production taxes as a result of higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased due to the higher lease operating costs and lower production volumes discussed above.

*Other.* Our general and administrative expenses increased primarily due to higher contract labor costs and lower capitalized costs in 2004. The cost per unit increased due to a combination of higher costs and lower production volumes discussed above.

*Year Ended December 31, 2003 Compared to Year Ended December 31, 2002*

Our EBIT for 2003 increased $283 million as compared to 2002. For the year ended December 31, 2003, natural gas prices, including hedges, increased 61 percent; however, we also experienced a significant decrease in production volumes as a result of asset sales, normal production declines, mechanical failures in several of our producing wells, a lower capital spending program and disappointing drilling results. The table below lists the significant variances in our operating results in 2003 as compared to 2002:

| | Variance | | | |
|---|---|---|---|---|
| | Operating Revenue | Operating Expense | Other[(1)] | EBIT Impact |
| | | Favorable/(Unfavorable) (In millions) | | |
| *Natural Gas Revenue* | | | | |
| Higher realized prices in 2003 | $ 792 | $ — | $— | $ 792 |
| Lower production volumes in 2003 | (416) | — | — | (416) |
| Impact from hedge program in 2003 versus 2002 | (119) | — | — | (119) |
| *Oil, Condensate and NGL Revenue* | | | | |
| Higher prices in 2003 | 62 | — | — | 62 |
| Lower production volumes in 2003 | (100) | — | — | (100) |
| Impact from hedge program in 2003 versus 2002 | (7) | — | — | (7) |
| *Depreciation, Depletion and Amortization Expense* | | | | |
| Higher depletion rate in 2003 | — | (116) | — | (116) |
| Lower production volumes in 2003 | — | 163 | — | 163 |
| Higher accretion expense for asset retirement obligations | — | (23) | — | (23) |
| *Production Costs* | | | | |
| Lower lease operating costs in 2003 | — | 71 | — | 71 |
| Higher production taxes in 2003 | — | (15) | — | (15) |
| *Other* | | | | |
| Ceiling test and other charges | — | (12) | — | (12) |
| Higher general and administrative costs in 2003 | — | (38) | — | (38) |
| Other | (2) | 3 | 40 | 41 |
| *Total variance 2003 to 2002* | $ 210 | $ 33 | $40 | $ 283 |

(1) Consists primarily of changes in transportation costs and other income.

*Operating revenues.* During 2003, we experienced a significant decrease in production volumes due to the sale of properties in New Mexico, Oklahoma, Texas, Colorado, Utah, and Offshore Gulf of Mexico, normal production declines, mechanical failures primarily in the Texas Gulf Coast and Offshore Gulf of Mexico regions, a lower capital spending program and disappointing drilling results. In addition, we incurred an unfavorable impact from our hedging program as our hedging losses were $44 million in 2003 as compared to $82 million of hedging gains in 2002. Despite lower production and unfavorable hedging results, revenues were higher due to higher average realized prices for natural gas and oil, condensate and NGL during 2003.

*Depreciation, depletion, and amortization expense.* Lower volumes in 2003 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs. We also recorded accretion expense related to our liabilities for asset retirement obligations in connection with the adoption of SFAS No. 143 in 2003.

*Production costs.* In 2003, we experienced lower production costs primarily due to the asset sales discussed above. However, we also incurred higher production taxes in 2003 as a result of higher natural gas and oil prices and larger tax credits taken in 2002 on high cost natural gas wells. Our cost per unit increased due to the higher production taxes and lower production volumes.

*Ceiling test and other charges.* In 2003, we incurred an impairment charge related to non-full cost pool assets of $5 million, net of gains on asset sales, non-cash ceiling test charges of $5 million associated with our operations in Brazil and $6 million in employee severance costs. In 2002, we incurred a non-cash ceiling test charge of $3 million associated with our operations in Brazil.

*General and administrative expenses.* Higher corporate overhead allocations and lower capitalized costs were the main factors leading to the increase in general and administrative expenses in 2003. The cost per unit increased due to a combination of higher costs and lower production volumes discussed above.

*Outlook for 2005*

Based on our strategy to develop a more balanced portfolio of natural gas and oil production and allocate more capital to longer life, slower decline projects and development projects in longer reserve life areas, we anticipate in 2005:

- A total capital expenditure budget, including acquisitions, of approximately $900 million.
- Daily production volumes to average in excess of 800 MMcfe/d.
- A focus on cost control, operating efficiencies, and process improvements to keep our per unit cash operating costs between $1.25/MMcfe and $1.40/MMcfe.
- Industry-wide increases in drilling costs and oilfield service costs that will require constant monitoring of capital spending programs.

**Non-regulated Business — Marketing and Trading Segment**

Our Marketing and Trading segment's operations focus on the marketing of our natural gas and oil production and the management of our remaining trading portfolio. Over the past several years, a number of significant events occurred in this business and in the industry:

*2001 and 2002*

- The deterioration of the energy trading environment followed by our announcement in November 2002 that we would reduce our involvement in the energy marketing and trading business and pursue an orderly liquidation of our trading portfolio.

*2003 and 2004*

- A challenging trading environment with reduced liquidity, lower credit standing of industry participants and a general decline in the number of trading counterparties.
- The ongoing liquidation of our historical trading portfolio.
- The announcement in December 2003 that we would change our operations to primarily focus on the physical marketing of natural gas and oil produced in our Production segment.

Currently, we do not anticipate that we will liquidate all of the transactions in our trading portfolio before the end of their contract term. We may retain contracts because (i) they are either uneconomical to sell or terminate in the current environment due to their contractual terms or credit concerns of the counterparty, (ii) a sale would require an acceleration of cash demands, or (iii) they represent hedges associated with activities reflected in other segments of our business, including our Production and Power segments. Changes to our liquidation strategy may impact the cash flows and the financial results of this segment.

Our Marketing and Trading segment's portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. The following is a discussion of the significant types of contracts used by our Marketing and Trading segment and how they impact our financial results:

*Natural Gas Contracts*

*Production-related and other natural gas derivatives*

*Derivatives designated as hedges.* We enter into contracts with third parties, primarily fixed for floating swaps, on behalf of our Production segment to hedge its anticipated natural gas production. These natural gas contracts consist of obligations to deliver natural gas at fixed prices. As of December 31, 2004, these contracts effectively hedged a total of 244 TBtu of our anticipated natural gas production through 2012. Of this total amount, 84 percent of these contracts were designated as accounting hedges on December 1, 2004. All contracts that are designated as hedges of our Production segment's natural gas and oil production are accounted for in the operating results of that segment.

*Production-related options.* These contracts, which are marked to market in our results each period, and are not accounting hedges, provide price protection to El Paso from natural gas price declines related to our natural gas production in 2005 and 2006. Entered into in the fourth quarter of 2004, these contracts will allow El Paso to achieve a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006.

In the first quarter of 2005, we entered into additional contracts that provide El Paso with a floor price of $6.00 per MMBtu on 30 TBtu of our natural gas production in 2007, and also capped us at a ceiling price of $9.50 per MMBtu on 60 TBtu of our natural gas production in 2006.

*Other natural gas derivatives.* Other natural gas derivatives consist of physical and financial natural gas contracts that impact our earnings as the fair values of these contracts change. These contracts obligate us to either purchase or sell natural gas at fixed prices. Our exposure to natural gas price changes will vary from period to period based on whether, overall, we purchase more or less natural gas than we sell under these contracts.

*Transportation-related contracts*

Our transportation contracts provide us with approximately 1.5 Bcf of pipeline capacity per day, for which we are charged approximately $149 million in annual demand charges. These contracts are accrual-based contracts that impact our gross margin as delivery or service under the contracts occurs. The following table details our transportation contracts:

| | Alliance | Texas Intrastate | Other |
|---|---|---|---|
| Daily capacity (MMBtu/day) | 160,000 | 435,000 | 910,000 |
| Annual demand charges (in millions) | $66 | $21 | $62 |
| Expiration | 2015 | 2006 | 2005 to 2028 |
| Receipt points | AECO Canada | South Texas | Various |
| Delivery points | Chicago | Houston Ship Channel | Various |

Historically, these contracts have resulted in significant losses to El Paso. The extent of these losses is dependent upon our ability to utilize the contracted pipeline capacity, which is impacted by:

- The difference in natural gas prices at contractual receipt and delivery locations;
- The capital needed to use this capacity (i.e. cash margins or letters of credit associated with the purchase and sale of natural gas to use the capacity); and
- The capacity required to meet our other long term obligations.

*Storage contracts*

During 2003, we eliminated a significant portion of our natural gas storage capacity contracts through the ongoing liquidation of our trading portfolio. We retained storage capacity of 4.7 Bcf at TGP's Bear Creek Storage Field and Enterprise Products Partners' Wilson storage facilities for operational and balancing purposes. We do not anticipate that our retained storage contracts will significantly impact our earnings in the future.

*Power Contracts*

*Tolling contracts.* We have two tolling contracts under which we supply fuel to power plants and receive the power generated by these plants. In exchange for this right to the power generated, we pay a demand charge. Our ability to recover these demand charges is primarily dependent upon the difference between the cost of fuel we supply to the plant and the value of the power we receive from the plant under the contract. Our tolling contracts are derivatives that impact our earnings as their fair value changes each period.

Our largest tolling contract provides us with approximately 548 MW of generating capacity at the Cordova power plant through 2019, for which we are charged $27 million to $32 million in annual demand charges. In addition, the Cordova power plant has the option to repurchase up to 50 percent of this generating capacity from us. We have historically experienced significant volatility in the fair value of this tolling contract, primarily due to changes in natural gas and power prices in the market that Cordova serves. We expect this volatility to continue. Our other tolling contract provides us with approximately 257 MW of generating capacity in the Alberta power pool through the third quarter of 2005, for which we expect to be charged $14 million of demand charges in 2005.

*Contracts related to power restructuring activities.* These contracts consist of long-term obligations to provide power for the restructured power contracts in our Power segment. With the sale of substantially all of our restructured power contracts, we have or are in the process of eliminating substantially all of these obligations, with the exception of our contract with Morgan Stanley related to UCF. This contract, which calls for us to deliver of up to 1,700 MMWh per year through 2016 at a fixed price, may continue to impact our earnings in the future.

*Operating Results*

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for each of the three years ended December 31. Because of the substantial changes in the composition of our portfolio, year-to-year comparability was affected:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Overall EBIT:* | | | |
| Gross margin[1] | $(508) | $(636) | $(1,316) |
| Operating expenses | (54) | (183) | (677) |
| Operating loss | (562) | (819) | (1,993) |
| Other income | 15 | 10 | 16 |
| EBIT | $(547) | $(809) | $(1,977) |

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Gross Margin by Significant Contract Type:* | | | |
| *Natural Gas Contracts* | | | |
| Production-related and other natural gas derivatives | | | |
| Changes in fair value on positions designated as hedges on December 1, 2004 | $(439) | $(425) | $ (601) |
| Changes in fair value on production-related options | 53 | — | — |
| Changes in fair value on other natural gas positions | 44 | 2 | (486) |
| Early contract terminations | 48 | (8) | — |
| Total production-related and other natural gas derivatives | (294) | (431) | (1,087) |
| Transportation-related contracts | | | |
| Demand charges | (149) | (156) | (36) |
| Settlements | 39 | 4 | 16 |
| Total transportation-related contracts | (110) | (152) | (20) |
| Storage contracts | | | |
| Demand charges | (2) | (21) | (15) |
| Settlements | — | 31 | 56 |
| Early contract terminations | — | (17) | — |
| Total storage contracts | (2) | (7) | 41 |
| Total gross margin — natural gas contracts | (406) | (590) | (1,066) |
| *Power Contracts* | | | |
| Changes in fair value on Cordova tolling agreement | (36) | 75 | (112) |
| Other power derivatives | | | |
| Changes in fair value | (85) | (96) | (138) |
| Early contract terminations | 19 | (25) | — |
| Total other power derivatives | (66) | (121) | (138) |
| Total gross margin — power contracts | (102) | (46) | (250) |
| Total gross margin | $(508) | $(636) | $(1,316) |

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

Overall, during 2004, 2003 and 2002, we experienced substantial losses in gross margin on our trading contracts due to a number of factors. In 2002, we experienced losses in our natural gas and power contracts as a result of general market declines in energy trading resulting from lower price volatility in the natural gas and power markets and a generally weaker trading and credit environment. Also contributing to the deterioration of the market valuations of our trading and marketing assets was the announcement in the fourth quarter of 2002 by many participants in the trading industry, including us, to discontinue or significantly reduce trading operations. Following this announcement, we liquidated a number of positions earlier than their scheduled maturity, which caused us to incur additional losses in gross margin in 2002 and 2003 than had we held those contracts to maturity. We also experienced difficulty in 2002 and 2003 in collecting on several claims from various industry participants experiencing financial difficulty, several of whom sought bankruptcy protection. Any settlements under ongoing proceedings in these matters could impact our future financial results.

Listed below is a discussion of other factors, by significant contract type, that affected the profitability of our Marketing and Trading segment during each of the three years ended December 31, 2004:

*Natural Gas Contracts*

*Production-related and other natural gas derivatives*

- *Derivatives designated as hedges.* The amounts in the above table represent changes in the fair values of derivative contracts that were designated as accounting hedges of our Production segment's natural gas production on December 1, 2004. The losses indicated were a result of increases in natural gas prices in 2002, 2003 and 2004 relative to the fixed prices in these contracts and these losses were historically included in our financial results. Following their designation as accounting hedges, future income impacts of these contracts will be reflected in our Production segment. However, the act of designating these contracts as hedges will have no impact on El Paso's overall cash flows in any period.

- *Production-related options.* As natural gas prices decreased in the fourth quarter of 2004, the fair value of the options we entered into in 2004 increased. These contracts had a fair value of $120 million as of December 31, 2004, which includes the premium we initially paid for the options. If gas prices remain above the option price of $6.00 per MMBtu, the fair value of these contracts will decrease over their term since they would expire unexercised. We paid a total net premium of $64 million for these options and the additional option contracts we entered into in the first quarter of 2005.

- *Other natural gas derivatives.* Because we were obligated to purchase more natural gas at a fixed price than we sold under these contracts during 2003 and 2004, the fair value of these contracts increased as natural gas prices increased during those years. In 2002, we incurred significant losses on these contracts because of lower price volatility and the deterioration of the energy trading environment described above.

- *Early contract terminations.* This amount includes a $50 million gain recognized on the termination of an LNG contract at the Elba Island facility in 2004.

*Transportation-related contracts*

- In the fourth quarter of 2002, we began accounting for our transportation contracts as accrual-based contracts with the adoption of EITF Issue No. 02-3. As a result, our 2002 results include the demand charges and accrual settlements we recorded during the fourth quarter of 2002. The mark-to-market losses on these contracts during the first nine months of 2002 are included in the change in fair value of our other natural gas derivatives above. Our annual demand charges on these contracts were approximately $149 million in 2004 and $156 million in 2003. The decrease in 2004 was due to the liquidation of a number of these positions prior to their original settlement dates.

- Our ability to use our Alliance pipeline capacity contract was relatively consistent during 2003 and 2004, allowing us to recover approximately 73 percent of the demand charges we paid each year. This resulted from the price differentials between the receipt and delivery points staying relatively consistent during these years, which resulted in EBIT losses from this contract of $15 million in 2003 and $17 million during 2004. Our Texas Intrastate transportation contracts incurred EBIT losses of $36 million in 2003 and $26 million in 2004. We were unable to utilize a significant portion of the capacity on these pipelines primarily due to a decrease in the price differentials between South Texas receipt points and Houston Ship Channel delivery locations under the contracts. If the differences in these prices do not improve, we will continue to experience losses on these contracts.

*Storage contracts*

In the fourth quarter of 2002, we began accounting for our storage contracts as accrual-based contracts with the adoption of EITF Issue No. 02-3. As a result, our 2002 results include the demand charges and accrual settlements we recorded during the fourth quarter of 2002. The mark-to-market losses on these contracts during the first nine months of 2002 are included in the change in fair value of our other natural gas derivatives. Our annual demand charges on these contracts were approximately $2 million in 2004 and $21 million in 2003. In 2002 and 2003, we terminated a significant number of our storage positions and recognized a $56 million gain in 2002 and a $31 million gain in 2003 on the withdrawal and sale of the gas held in these storage locations. Based on our actions, our remaining contracts with the Wilson and Bear Creek storage facilities should not have a significant impact on the future financial results of this segment.

*Power Contracts*

*Cordova tolling agreement*

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. In 2003, forecasted power prices increased relative to natural gas prices, resulting in a significant increase in the fair value of this contract. In 2004, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract. Additionally, although the Cordova power plant historically sold its power into a relatively illiquid power market in the Midwest, this power market was incorporated into the more liquid Pennsylvania-New Jersey-Maryland power pool in 2004. We believe that this change will reduce the volatility of the fair value of the contract in the future.

*Other power derivatives*

- Historically, many of our contract origination activities related to power contracts. Because of the changes in the energy trading environment and the change in focus of our Marketing and Trading segment, these activities substantially decreased from 2002 to 2004.

- The ongoing liquidation of our trading book significantly impacted our power contracts. We also recorded a $25 million gain on the termination of a power contract with our Power segment in 2004, which was eliminated in El Paso's consolidated results.

- In the first quarter of 2005, we assigned our contracts to supply power to our Power segment's Cedar Brakes I and II entities to Constellation Energy Commodities Group, Inc. We recorded a loss of approximately $30 million during the fourth quarter of 2004 upon signing the assignment and termination agreement. These contracts decreased in fair value by $64 million, $67 million and $48 million in 2004, 2003 and 2002.

- In the first quarter of 2002, we recorded an $80 million gain related to a power supply agreement that we entered into with our Power segment. The gain, which was associated with the UCF restructured power contract, was eliminated from El Paso's consolidated results. Later in 2002, we terminated this contract and entered into a new power supply agreement with Morgan Stanley related to UCF. The Morgan Stanley contract decreased in fair value by $72 million, $77 million and $58 million in 2004, 2003 and 2002.

- Our remaining power contracts, which include those that are used to manage the risk associated with our obligations to supply power, increased in fair value by $81 million in 2004 and $48 million in 2003.

*Operating Expenses*

Operating expenses in our Marketing and Trading segment decreased significantly each year due primarily to the following:

- In 2002 and 2003, we recorded $487 million and $26 million of charges in operating expenses related to the Western Energy Settlement. In late 2003, this obligation was transferred to our corporate operations.
- In 2003 and 2004, we recorded $28 million and $10 million of bad debt expense associated with a fuel supply agreement we have with the Berkshire power plant.
- As a result of the decision in November 2002 to reduce the size of our trading portfolio, we experienced a significant decline in employee headcount, which resulted in lower general and administrative expenses in 2003. This decline in headcount, coupled with the closing of our London office in 2003, contributed to further decreases in general and administrative expenses in 2004.
- Overall cost reduction efforts at the corporate level and our reduced level of operations resulted in lower corporate overhead being allocated to us in 2003 and 2004.

**Non-regulated Business — Power Segment**

As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also included domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses. Our ongoing focus within the power segment will be to maximize the value of our assets in Brazil. We have designated our other international power operations as non-core activities, and expect to exit these activities in the future as market conditions warrant.

*International Power Plant Operations*

*Brazil.* As of December 31, 2004, our Brazilian operations include our Macae, Porto Velho, Manaus, Rio Negro, and Araucaria power plants and our investments in the Bolivia to Brazil and Argentina to Chile pipelines.

- *Macae.* Our Macae power plant sells a majority of its power to the wholesale Brazilian power market. Macae also has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras did not pay amounts due under the contract for December 2004 and January 2005 and filed a lawsuit and for arbitration. For a further discussion of this matter, see Part II, Item 8, Financial Statements and Supplementary Data, Note 17. The future financial performance of the Macae plant will be affected by the outcome of this dispute and by regional changes in power markets.
- *Porto Velho.* Our Porto Velho plant sells power to Eletronorte under two power sales agreements that expire in 2010 and 2023. Eletronorte absorbs substantially all of the plant's fuel costs and purchases all of the power the plant is able to generate, as long as the plant operates within availability levels required by these contracts. As a result, the profitability of the plant is dependent primarily on maintaining these availability levels through efficient operations and maintenance practices. These availability levels are expected to decrease in 2005 because of an equipment failure at the plant during 2004 that is expected to be repaired by the first quarter of 2006. In addition, we are negotiating potential contractual amendments with Eletronorte that may alter the volumes and prices of power to be sold under the contracts and may affect our future earnings. For a further discussion of these negotiations, see Part II, Item 8, Financial Statements and Supplementary Data, Note 17.
- *Manaus and Rio Negro.* In January 2005, we signed new power sales contracts for our Manaus and Rio Negro power plants with Manaus Energia. Under these new contracts, Manaus Energia will pay a price for its power that is similar to that in the previous contracts. In addition, Manaus

Energia will assume ownership of the Manaus and Rio Negro plants in 2008. Based on this ownership transfer and the contract terms, we will deconsolidate the plants in the first quarter of 2005 and begin to account for them as equity investments. In addition, the earnings from these assets will decrease as a result of the new contracts.

- *Other.* The power sales contract of the Araucaria power plant is currently in international arbitration due to non-payment by the utility that purchases power from the plant. As a result, Araucaria ceased its operations in 2003. For a further discussion of these arbitration proceedings, see Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

Our two pipelines began operations in 2003 and generate income through the transportation of natural gas to various customers in South America.

*Asia.* Our Asian operations include interests in 15 power plants, 13 of which are equity investments. These facilities sell electricity and electrical generating capacity under long-term power sales agreements with local transmission and distribution companies, many of which are government controlled. The majority of these contracts allow for changes in fuel costs to be passed through to the customer through power prices. The economic performance of these facilities is impacted by the level of electricity demand and changes in the political and regulatory environment in the countries they serve as well as the relative cost of producing that power. We recorded an impairment of these assets in 2004 in connection with our decision to sell these assets.

*Other International.* We have interests in 10 power facilities located in South and Central America and Europe, most of which are equity investments. These facilities sell electricity and electrical generating capacity under long-term and short-term power sales agreements with local transmission and distribution companies as well as to the local spot markets. The economic performance of these facilities is impacted by fuel prices, the level of demand for electricity, the level of competition from other power generators, changes in the political and regulatory environment in the countries they serve, and the relative cost of producing power. The performance of our facilities in Central America is also affected by variances in the level of rainfall in the region. As the level of rainfall increases, the level of generation from hydroelectric plants increases which can negatively impact power pricing in the spot market. We have recently announced that we are considering the sale of a number of these assets, although at this time we have not actively marketed them. As this process progresses we will continue to assess the value of these assets which may result in impairments.

*Domestic Power Plant Operations*

Our domestic operations as of December 31, 2004, primarily consist of an equity ownership in a natural gas-fired power plant, Midland Cogeneration Venture (MCV). The price of electricity sold by MCV is indexed to coal, while the plant is fueled by natural gas, which it purchases under both long-term contracts and on the spot market. Changes in the relationship between coal and natural gas prices directly impact the economic performance of this facility. In 2004, we recorded an impairment of our interest in this plant based on a decline in the value of the investment that we considered to be other than temporary.

During 2004 and the first quarter of 2005, we sold our interests in 33 domestic power plants. With these sales, we incurred substantial impairments in 2003 and 2004. As a result of these sales, we will have substantially lower earnings in our Power segment.

*Domestic Power Contract Restructuring Business*

In 2002 and 2003, we maintained or completed several contract restructuring transactions, the largest of which was UCF. During 2004, we completed the sale of UCF and its related restructured power contract, and entered into an agreement to sell our ownership in Cedar Brakes I and II, and their related restructured power contracts. As of December 31, 2004, we held an interest in Mohawk River Funding II and Cedar Brakes I and

II. We completed the sale of Cedar Brakes I and II in the first quarter of 2005 and are evaluating potential buyers for Mohawk River Funding II.

*Operating Results*

Below are the overall operating results and analysis of activities within our Power segment for each of the three years ended December 31. Substantial changes in the business during these periods affected year-to-year comparability.

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Overall EBIT:* | | | |
| Gross margin[1] | $ 643 | $ 865 | $1,103 |
| Operating expenses | | | |
| Loss on long-lived assets | (583) | (185) | (160) |
| Other operating expenses | (468) | (693) | (591) |
| Operating income (loss) | (408) | (13) | 352 |
| Earnings from unconsolidated affiliates | | | |
| Impairments and net losses on sale | (390) | (347) | (426) |
| Equity in earnings | 154 | 256 | 170 |
| Other income (expense) | 75 | 76 | (84) |
| EBIT | $ (569) | $ (28) | $ 12 |
| *EBIT by Area:* | | | |
| *International power* | | | |
| Brazilian operations | $ 69 | $ 177 | $ 78 |
| Asian operations | (140) | 49 | (3) |
| Other | 12 | 70 | (243) |
| | (59) | 296 | (168) |
| *Domestic power plant operations* | | | |
| MCV | (171) | 29 | 28 |
| Sold or sale announced | (58) | (400) | 55 |
| Other | — | (12) | (3) |
| | (229) | (383) | 80 |
| *Domestic power contract restructuring activities* | (228) | 150 | 341 |
| *Power turbine impairments* | (1) | (33) | (162) |
| *Other*[2] | (52) | (58) | (79) |
| EBIT | $ (569) | $ (28) | $ 12 |

(1) Gross margin for our Power segment consists of revenues from our power plants and the initial net gains and losses incurred in connection with the restructuring of power contracts, as well as the subsequent revenues, cost of electricity purchases and changes in fair value of those contracts. The cost of fuel used in the power generation process is included in operating expenses.

(2) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance, and engineering costs. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations.

*International Power.* The following table shows significant factors impacting EBIT in our international power business in 2004, 2003 and 2002:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Brazil* | | | |
| Earnings from consolidated and unconsolidated plant operations | $ 236 | $177 | $ 97 |
| Manaus and Rio Negro impairment | (167) | — | — |
| Contract termination fee | — | — | (19) |
| Total Brazil | 69 | 177 | 78 |
| *Asia* | | | |
| Earnings from consolidated and unconsolidated plant operations | 61 | 49 | 45 |
| Asian asset impairments | (212) | — | — |
| PPN impairment | — | — | (41) |
| Meizhou Wan impairment | — | — | (7) |
| Other | 11 | — | — |
| Total Asia | (140) | 49 | (3) |
| *Other International Power* | | | |
| Earnings from consolidated and unconsolidated plant operations | 24 | 42 | 102 |
| Argentina gain on sale (impairment) | — | 28 | (342) |
| Other impairments | (3) | — | (3) |
| Other | (9) | — | — |
| Total Other | 12 | 70 | (243) |
| Total | $ (59) | $296 | $(168) |

*Brazil.* During 2002 and 2003, we completed the construction of several power plants and pipelines, which allowed them to reach full operational capacity. However, our financial results during each of the three years ended December 31, 2004 were impacted significantly by regional economic and political conditions, which affected the renegotiation of several of the power contracts for our Brazilian power plants. Below is a discussion of each of our significant assets in Brazil.

*Macae and Porto Velho*

Through the first quarter of 2003, we conducted a majority of our power plant operations in Brazil through Gemstone, an unconsolidated joint venture. In April 2003, we acquired the joint venture partner's interest in Gemstone and began consolidating Gemstone's debt and its interests in the Macae and Porto Velho power plants. As a result, our operating results for 2002 and the first quarter of 2003 include the equity earnings we earned from Gemstone, while our consolidated operating results for all other periods in 2003 and 2004 include the revenues, expenses and equity earnings from Gemstone's assets.

The EBIT we earned from our Macae plant's operations was $172 million, $156 million, and $136 million in 2004, 2003, and 2002. The increase in 2003 was primarily due to Macae reaching full operational capacity in the third quarter of 2002. In addition, the consolidation of Gemstone described above improved our EBIT in 2003 and 2004 since the interest and taxes incurred by Gemstone were no longer included in EBIT.

The EBIT we earned from our Porto Velho plant's operations was $28 million, $28 million and $23 million in 2004, 2003, and 2002. The increase in 2003 was primarily due to Porto Velho reaching full operational capacity in mid-2003. In the fourth quarter of 2004, our Porto Velho plant experienced an equipment failure that is expected to temporarily reduce the output of the plant by approximately 30 percent. This equipment failure is expected to be repaired by the first quarter of 2006.

Our combined net exposure on the Macae and Porto Velho plants was approximately $0.8 billion at December 31, 2004. We are currently in negotiations over the Porto Velho contracts with Eletronorte and in a dispute with Petrobras over the Macae contract. As these negotiations and disputes progress, it is possible that impairments of these assets may occur, and these impairments may be significant. For a further discussion of these negotiations and disputes, see Part II, Item, 8, Financial Statements and Supplementary Data, Note 17.

*Manaus and Rio Negro*

In 2003, we began negotiating the extension of the Manaus and Rio Negro power contracts, which were to expire in 2005 and 2006. Based on the status of our negotiations to extend the contracts, which was negatively impacted by changes in the Brazilian political environment in 2004, we recorded a $167 million impairment of our investment in Manaus and Rio Negro in 2004. We completed an extension of these contracts during the first quarter of 2005. The Manaus and Rio Negro plants had earnings from plant operations of $30 million in 2004, $12 million in 2003 and $18 million in 2002.

*South American Pipelines*

The EBIT for our Brazilian operations includes EBIT earned by our Bolivia to Brazil and Argentina to Chile pipelines. This amount was $28 million in 2004 and $18 million in 2003. Our EBIT earned by these pipelines was not significant in 2002. Increases during the three year period were primarily due to the Bolivia to Brazil pipeline reaching full operational capacity in the third quarter of 2003.

*Asia.* During the fourth quarter of 2004, we recorded a $212 million charge on our Asian power assets in connection with our decision to pursue the sale of these assets. These impairment amounts were based on our estimates of the fair value of these projects. In 2005, we engaged a financial advisor to assist us in the sale of these assets. In the first quarter of 2005, we sold our investment in the PPN power facility in India for $20 million. We had impaired this plant in 2002 primarily because of regional political and economic events at that time. As the sales process continues, we will continue to update the fair value of our Asian assets, which may result in further impairments.

From 2002 to 2004, earnings from our Asian power assets were relatively stable as the underlying plants maintained steady levels of availability and production. Higher fuel costs during these periods did not materially impact these plants' operations as substantially all of the higher fuel costs were passed through to the power purchasers through higher contracted power prices.

However, during this three year period, several other significant events occurred that improved our financial performance from these assets, including:

- The conversion of two of our Chinese power plants from heavy fuel oil to natural gas, which lowered the production costs at these facilities;
- The issuance of debt at our Meizhou Wan plant in 2004, which reduced liquidity concerns about the plant's operation. This plant had been partially impaired in 2002 based on those concerns;
- The favorable completion of negotiations with Philippine regulators on fuel and power prices at our East Asia plants; and
- The closing of our Singapore office in 2002, which lowered operating expenses.

*Other International.* The earnings from our other international operations have decreased from 2002 to 2004 due primarily to economic difficulties in some of the countries that we serve as well as specific transactions that affected the profitability of the underlying plants. Major factors contributing to the decreases were:

- *Dominican Republic.* An economic crisis in the Dominican Republic during 2002 and 2003 significantly reduced the amount of power generated and impacted our ability to collect some of the receivables at our power plants in the country during 2003 and 2004. The Dominican Republic's economy began to improve in late 2004 following the election of a new president. See Part II, Item 8, Financial Statements and Supplementary Data, Note 22 for a further discussion of our investments in the Dominican Republic.

- *El Salvador.* In 2002, we restructured a power contract at our El Salvador power facility, which resulted in a $77 million gain in 2002. This restructuring converted the plant to a merchant facility that sells power under short-term contracts and on the open market. As a result, the power and resulting earnings generated by this plant in 2002 were higher than in 2003 and 2004.

- *Argentina.* In 2002, we impaired our investment in Argentina based on new legislation resulting from an economic crisis in Argentina. We sold these plants in 2003 and are attempting to recover a portion of these losses through international arbitration.

- *Other.* Our other international operations are also sensitive to changes in the local demand for power and the cost of fuel to run the power facilities. Our power plant in England benefited from increases in demand and power prices in 2004, but this was largely offset by higher fuel prices at our Central American power plants.

As part of our long term business strategy, we are considering the sale of a number of our other international power assets. As these sales occur and/or as market indicators of fair value become available, it is possible that impairments of these assets may occur, and these impairments may be significant.

*Domestic Power.* The following table shows significant factors impacting EBIT within our domestic power business in 2004, 2003, and 2002:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *MCV* | | | |
| Earnings from plant operations | $ (10) | $ 29 | $ 28 |
| Impairments | (161) | — | — |
| *Assets sold or expected to be sold in 2005* | | | |
| Earnings from consolidated and unconsolidated plant operations[1] | 47 | 103 | 144 |
| Impairments and write-offs | (105) | (503) | (89) |
| *Other* | — | (12) | (3) |
| Total | $(229) | $(383) | $ 80 |

[1] During 2004 and 2003, we recorded $60 million and $105 million of operating income generated by the power plants from Chaparral, an equity investment we consolidated effective January 1, 2003. Prior to January 2003, we recorded our earnings from the Chaparral power plants through the equity earnings and management fees we received which were approximately $124 million in 2002.

*MCV.* Our MCV power plant is a natural gas-fired plant, which sells its power at a contracted price that is indexed to coal prices. During 2004, MCV experienced reduced EBIT primarily because natural gas prices increased at a faster rate than coal prices. This decrease in EBIT was magnified by an increase in the volume of power MCV was required to generate. In January 2005, MCV received regulatory approval to reduce the required level of power generation. In the fourth quarter of 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

*Assets sold or to be sold in 2005.* During the three years ended December 31, 2004, we recorded significant impairments in our domestic power business as discussed below.

- In 2004, 2003, and 2002, we incurred approximately $105 million, $208 million and $89 million of asset impairments, net of realized gains and losses, in our domestic power business based on the anticipated sale of these assets as well as operational and contractual issues at several of these facilities. During 2004, these amounts included $81 million related to impairing the earnings of assets held for sale, in addition to $24 million of impairments, net of gains and losses, on long-lived assets related to our held for sale merchant and contracted plants. We also incurred a $25 million loss on the termination of a power contract with our Marketing and Trading segment related to one of the assets sold, which is reflected in our 2004 earnings from plant operations.
- In 2003, we also:
  - Recorded an impairment of our Chaparral investment of $207 million based on a decline in the investment's value that was considered to be other than temporary. See Part II, Item 8, Financial Statements and Supplementary Data, Notes 2, 3, and 22 for further discussion of these matters.
  - Wrote-off a receivable of $88 million from Milford Power LLC related to the transfer of our interest in Milford Power LLC to its lenders after continued difficulties with this facility.

*Domestic Power Contract Restructuring.* The following table shows significant factors impacting EBIT within our domestic power contract restructuring activities in 2004, 2003 and 2002:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Restructuring gain* | $ — | $ — | $331 |
| *Impairments and gains (losses) on sale* | | | |
| UCF | (99) | — | — |
| Cedar Brakes I and II | (227) | — | — |
| Other | — | (15) | — |
| *Change in fair value of contracts* | | | |
| UCF, Cedar Brakes I and II | 97 | 119 | 9 |
| MRF II | 4 | 10 | — |
| Other | (2) | 15 | — |
| *Other* | (1) | 21 | 1 |
| EBIT | $(228) | $150 | $341 |

In 2002, we restructured several above-market, long-term power sales contracts with regulated utilities that were originally tied to older power plants. These contracts were amended so that the power sold to the utilities was not required to be delivered from the specified power generation plant, but could be obtained in the wholesale power market. As a result of our credit rating downgrades and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and are exiting such activities which will reduce our EBIT in future periods. For a further discussion of our power restructuring activities, see below and Part II, Item 8, Financial Statements and Supplementary Data, Note 10.

*Restructuring Gain.* During 2002, we restructured the power sales contracts at our Eagle Point power facility (also known as UCF) and our Mount Carmel power plant, which resulted in combined net gains of $501 million (net of minority interest.) Prior to restructuring the contracts, the power plants' power purchase contracts were accounted for using accrual accounting. Following the restructuring, the power purchase agreements were accounted for as derivatives and recorded at fair value, resulting in a net gain on the date the contracts were restructured. In conjunction with the UCF restructuring in 2002, we paid a $90 million contract termination fee to terminate a steam contract between our Eagle Point power plant and the Eagle Point refinery and we recorded an $80 million loss on a power supply agreement that we entered into with our Marketing and Trading segment. The $90 million and $80 million losses eliminated in El Paso's consolidated results.

*Sale of UCF/Cedar Brakes I and II.* During 2004, we sold UCF and in March 2005 we sold Cedar Brakes I and II. These sales resulted in impairments on the Cedar Brakes I and II entities and on UCF in 2004.

**Non-regulated Business — Field Services Segment**

Our Field Services segment conducts our remaining midstream activities, which primarily include gathering and processing assets in south Louisiana. During 2002, 2003 and 2004, we held significant general and limited partner interests in GulfTerra and Enterprise. From December 2003 to January 2005, we sold all of our general and limited partner interests in GulfTerra and Enterprise, our South Texas processing plants, and our interests in the Indian Springs natural gas gathering and processing assets to Enterprise in a series of transactions described further in Part II, Item 8, Financial Statements and Supplementary Data, Note 22.

During 2003 and 2004, the primary source of earnings in our Field Services segment was from our interests in GulfTerra and Enterprise. On the sale of our interests in GulfTerra in 2003 and 2004, we recognized significant gains, as well as a goodwill impairment of $480 million. Prior to the sale of our interests in GulfTerra, we also received management fees under an agreement to provide operational and administrative services to the partnership. In addition, we received reimbursements for costs paid directly by us on GulfTerra's behalf. For the twelve months ended December 31, 2004, 2003, and 2002, we received approximately $71 million, $91 million, and $60 million in management fees and cost reimbursements. As a result of the sale of our general and limited partnership interests in September 2004, we no longer receive management fees and, as the result of the sale of our remaining interest in January 2005, we will no longer recognize equity earnings related to these investments.

Our significant remaining obligations to Enterprise are to provide an estimated $45 million in payments to Enterprise during the next three years and provide for the reimbursement of a portion of Enterprise's future pipeline integrity costs related to assets sold by us to GulfTerra in 2002 for which we recorded a $74 million liability in 2003. As a result of regulatory changes relating to pipeline integrity and subsequent negotiations with Enterprise, we reduced our estimated obligation to Enterprise by approximately $9 million during the fourth quarter of 2004. In addition, we are to provide for the reimbursement of a portion of GulfTerra's maintenance expenses on certain previously sold assets for which we recorded an estimated liability and a charge to operating expenses of $8 million in 2004. For further discussion of these indemnification agreements, see Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

During 2004, our earnings and cash distributions received from GulfTerra and Enterprise were as follows:

| | Earnings Recognized | Cash Received |
|---|---|---|
| | (In millions) | |
| General partner's share of distributions | $ 65 | $ 67 |
| Proportionate share of income available to common unit holders | 16 | 26 |
| Series C units | 14 | 24 |
| Gain on issuance by GulfTerra of its common units | 5 | — |
| | $100 | $117 |

Below are the operating results and analysis of the results for our Field Services segment for each of the three years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Gathering and processing gross margins[1] | $ 165 | $ 132 | $ 349 |
| Operating expenses | | | |
| Gain (loss) on long-lived assets | (508) | (173) | 179 |
| Other operating expenses | (122) | (152) | (255) |
| Operating income (loss) | (465) | (193) | 273 |
| Other income | | | |
| Gain (loss) on unconsolidated affiliates | 501 | 181 | (50) |
| Other income | 84 | 145 | 66 |
| EBIT | $ 120 | $ 133 | $ 289 |
| Volumes and Prices: | | | |
| Gathering | | | |
| Volumes (BBtu/d) | 203 | 357 | 3,023 |
| Prices ($/MMBtu) | $ 0.10 | $ 0.18 | $ 0.17 |
| Processing | | | |
| Volumes (BBtu/d) | 2,780 | 3,206 | 3,920 |
| Prices ($/MMBtu) | $ 0.14 | $ 0.10 | $ 0.10 |

(1) Gross margins consist of operating revenues less cost of products sold. We believe that this measurement is more meaningful for understanding and analyzing our Field Services segment's operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Below is a summary of significant factors and related discussions affecting EBIT for each of the three years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| *Gathering and Processing Activities* | | | |
| Gathering and processing margins | $ 165 | $ 132 | $ 349 |
| Operating expenses | (122) | (152) | (255) |
| Other | 10 | (7) | (53) |
| | 53 | (27) | 41 |
| *GulfTerra/Enterprise Related Items* | | | |
| Sale of assets to GulfTerra | | | |
| San Juan, Texas, and New Mexico assets | — | — | 210 |
| Release of Chaco lease obligation | — | 67 | — |
| Pipeline integrity indemnification | 9 | (74) | — |
| Sale of assets/interests to Enterprise | | | |
| Gain on sale of GP/LP interests | 507 | 266 | — |
| Minority interest | (32) | — | — |
| South Texas | (11) | (167) | — |
| Indian Springs | (13) | — | — |
| Goodwill impairment | (480) | — | — |
| Equity earnings | 100 | 153 | 69 |
| | 80 | 245 | 279 |
| *Other Asset Sales* | | | |
| Asset impairments and gains (losses) on sales | | | |
| North Louisiana | — | — | (66) |
| Dauphin Island/Mobile Bay | — | (86) | — |
| Other | (13) | 1 | 35 |
| | (13) | (85) | (31) |
| *EBIT* | $ 120 | $ 133 | $ 289 |

*Gathering and Processing Activities.* During the three years ended December 31, 2004, we have experienced a decrease in our gross margin with a corresponding decrease in our operation and maintenance expenses primarily as a result of asset sales. Additionally, our gathering and processing margins during these periods have been impacted by the spread between NGL prices and natural gas prices. As these spreads increase, we generally increase the NGL volumes we extract, which affects our margin. In 2003, our margins were negatively impacted by a decrease in these spreads as natural gas prices relative to NGL prices increased, which also caused us to reduce the amount of NGL extracted as compared to 2002. However, in 2004 these margins were positively impacted by an increase in these spreads as NGL prices recovered, which also caused us to increase the amount of NGL extracted by our natural gas processing facilities in south Texas. In addition, our margin attributable to the marketing of NGL increased in 2004 as a result of lower fuel and transportation costs. In the future, the margins for our remaining assets will remain sensitive to the spread between natural gas pricing and NGL pricing.

*GulfTerra/Enterprise Related Items.* During 2002 and 2003, we sold a substantial amount of our assets to GulfTerra which decreased our gross margin and operating expenses, while at the same time increasing our equity earnings from our general and limited partner interests in GulfTerra. Listed below are the significant transactions with GulfTerra:

- *2002* — the gain on our sale of our Texas and New Mexico gathering and pipeline assets and our San Juan gathering assets.

• *2003* — the release from our Chaco lease obligation in return for communication assets and clarification of our obligation to provide for pipeline integrity costs through 2006.

From December 2003 to January 2005, we entered into a series of transactions with Enterprise in which we sold all of our interests in GulfTerra. In December 2003, we sold 50 percent of our interest in GulfTerra to Enterprise and recorded a gain on the sale in other income. At the same time, we recorded an impairment of our south Texas assets in operating expenses based on the planned sale of these assets to Enterprise in 2004. In September 2004, we completed the sale of our remaining 50 percent interest in the general partner of GulfTerra to Enterprise and recorded a gain on the sale in other income. As a result of the substantial reduction in our asset base primarily from these sales to Enterprise, we recorded an impairment in operating expenses for the entire amount of goodwill upon determination that the goodwill in this segment was no longer recoverable. Finally, at the end of 2004, we entered into negotiations to sell our Indian Springs assets to Enterprise and recorded an impairment charge in operating expenses on these assets based on their planned sale in 2005. We completed the sale of the Indian Springs assets in January 2005. We also sold our remaining general and limited partnership interests in Enterprise for $425 million in January 2005.

*Other Asset Sales.* In 2002, we recorded an impairment in operating expenses for our north Louisiana assets based on their planned sale, which was completed in 2003. In 2003, we recorded an impairment in other income of our investment in our Dauphin Island Gathering system and Mobile Bay Processing plant based on the planned sale of these investments. We sold these investments in August 2004.

**Corporate and Other Expenses, Net**

Our corporate operations include our general and administrative functions as well as a telecommunications business, petroleum ship charter operations and various other contracts and assets, including financial services and LNG and related items, all of which are immaterial to our results. The following table presents items impacting the EBIT in our corporate operations for the years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Impairments, contract terminations and gains (losses) on asset sales: | | | |
| Telecommunications business | $ — | $(396) | $(168) |
| LNG business | — | (108) | — |
| Aircraft | 8 | (8) | — |
| Earnings from operations: | | | |
| Financial services business | 17 | 21 | (18) |
| Petroleum ship charters | 15 | 1 | (13) |
| Telecommunications business | — | (44) | (65) |
| Restructuring charges | (91) | (91) | (51) |
| Debt gains (losses): | | | |
| Foreign currency fluctuations on Euro-denominated debt | (26) | (112) | (95) |
| Early extinguishment/exchange of debt | (18) | (49) | 21 |
| Change in litigation, insurance and other reserves | (116) | (19) | 14 |
| Other | (3) | (47) | (12) |
| Total EBIT | $(214) | $(852) | $(387) |

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. During 2004, we incurred additional legal costs related to changes in our estimated reserves for these existing legal matters. These changes were based on ongoing assessments, developments and evaluations of the possible outcomes of these matters. We also incurred accretion expense related to our Western Energy Settlement. Our Western Energy Settlement accrual assumes that we will make payments to claimants through 2023. If we retire this obligation earlier than that period, we could incur additional charges. Finally, in 2004, we increased our insurance reserves by approximately $30 million. This accrual related to our decision to withdraw from a mutual insurance company in which we were a member and an accrual for additional premiums in another. In all of our legal and insurance matters, we evaluate each suit and claim as to its merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results.

As discussed in Part II, Item 8, Financial Statements and Supplementary Information, Note 4, we accrued $80 million in 2004 related to the consolidation of our Houston-based operations. Our estimated relocation costs are based on a discounted liability, which includes estimates of future sublease rentals. Our earnings in future periods will be impacted by the extent to which actual sublease rentals differ from our estimates, and by accretion of this discounted liability, which is estimated to be approximately $8 million for 2005. In total, had estimates of sublease rentals for vacated space that was not subleased as of December 31, 2004 been excluded from our calculations, our discounted liability would have been approximately $121 million versus the amount we recorded. For 2005, if we are unable to collect the estimated sublease rentals included in our accrual, we could incur an additional $3 million in rental expense. We are also pursuing the sale of our telecommunications facility in Chicago. As the sales process progresses we will continue to assess the value of this facility which may result in an impairment.

**Interest and Debt Expense**

Below is an analysis of our interest and debt expense for each of the three years ended December 31 (in millions):

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Long-term debt, including current maturities | $1,510 | $1,628 | $1,153 |
| Revolving credit facilities | 109 | 121 | 16 |
| Commercial paper | — | — | 26 |
| Other interest | 27 | 73 | 130 |
| Capitalized interest | (39) | (31) | (28) |
| Total interest and debt expense | $1,607 | $1,791 | $1,297 |

*Year Ended December 31, 2004 Compared to Year Ended December 31, 2003*

During 2004, our total interest and debt expense decreased primarily due to the retirements of long-term debt and other financing obligations (net of issuances) during 2003 and 2004. During 2004, we also paid off $850 million of borrowings under our previous $3 billion revolving credit facility. However, these repayments were offset by $1.25 billion borrowed under the new $3 billion credit agreement entered into in November 2004 and related charges and fees incurred with entering into the new credit agreement.

*Year Ended December 31, 2003 Compared to Year Ended December 31, 2002*

During 2003, total interest and debt expense increased compared with 2002 as we issued additional debt securities and consolidated various financing obligations including those associated with Chaparral, Gemstone, Lakeside. We also reclassified certain of our preferred securities as long-term debt. Finally, interest expense on revolving credit facilities increased in 2003 from additional borrowings in 2003 as compared to 2002.

**Distributions on Preferred Interests of Consolidated Subsidiaries**

Our distributions on preferred securities decreased significantly between 2002 and 2004. During this period, we redeemed a number of obligations including those related to our Clydesdale, Trinity River, and Coastal Securities financing arrangements. We also reclassified our Coastal Finance I and Capital Trust I mandatorily redeemable securities to long-term debt upon the adoption of SFAS No. 150 in 2003, and began recording the distributions on these securities as interest expense. Our remaining preferred interests at December 31, 2004 consists of $300 million of 8.25% preferred stock of our consolidated subsidiary, El Paso Tennessee Pipeline Co.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Part II, Item 8, Financial Statements and Supplementary Data, Notes 15 and 16.

**Income Taxes**

Income taxes for 2003 and 2002 have been restated. For a further discussion see Part II, Item 8. Financial Statements and Supplementary Data, Note 1.

Income taxes for the years ended December 31, 2004, 2003 and 2002 were $25 million, ($469) million and ($641) million resulting in effective tax rates of (3) percent, 44 percent and 34 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes, net of federal income tax effect;
- earnings/losses from unconsolidated affiliates where we anticipate receiving dividends;
- foreign income taxed at different rates;
- abandonments and sales of foreign investments;
- valuation allowances;
- non-deductible dividends on the preferred stock of subsidiaries;
- non-conventional fuel tax credits; and
- non-deductible goodwill impairments.

For a reconciliation of the statutory rate to our effective tax rate, as well as matters that could impact our future tax expense, see below and Part II, Item 8, Financial Statements and Supplementary Data, Note 7.

For 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the GulfTerra transactions and the impairments of certain of our foreign investments. The sale of our interests in GulfTerra associated with the merger between GulfTerra and Enterprise in September 2004 resulted in a significant net taxable gain (compared to a lower book gain) and significant tax expense due to the non-deductibility of a significant portion of the goodwill written off as a result of the transaction. The impact of this non-deductible goodwill increased our tax expense in 2004 by approximately $139 million. See Part II, Item 8, Financial Statements and Supplementary Data, Note 22 for a further discussion of the merger and related transactions. Additionally, we received no U.S. federal income tax benefit on the impairment of certain of our foreign investments. The effective tax rate for 2004 absent these items would have been 32 percent.

For 2003, our overall effective tax rate on continuing operations was significantly different than the statutory rate due, in part, to $43 million of tax benefits related to abandonments and sales of certain of our foreign investments. The effective tax rate for 2003 absent these tax benefits would have been 40 percent.

In 2004, Congress proposed but failed to enact legislation that would disallow deductions for certain settlements made to or on behalf of governmental entities. It is possible Congress will reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement and could result in a write-off of some or all of the associated tax benefits. In such an event, our tax expense would increase. Our total tax benefits related to the Western Energy Settlement were approximately $400 million as of December 31, 2004.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not provided U.S. deferred taxes on foreign earnings where such earnings were intended to be indefinitely reinvested outside the U.S. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

As part of our long-term business strategy, we anticipate that we will sell our Asian power investments. As further discussed Part II, in Item 8, Financial Statements and Supplementary Data, Note 7, we have not historically recorded United States deferred taxes on book versus tax basis differences in these investments because our historical intent was to indefinitely reinvest earnings from these projects outside the United States. In 2004, our intent on these assets changed such that we now intend to use the proceeds from the sale within the U.S. As a result, we recorded U.S. deferred tax liabilities for those instances where the book basis in our investment exceeded the tax basis in 2004. At this time, however, due to uncertainties as to the manner, timing and approval of the sale transactions, we have not recorded U.S. deferred tax assets for those instances where the tax basis in our investment exceeded the book basis, except in instances where we believe the realization of the asset is assured. As these uncertainties become known, we will record additional tax effects to reflect the ultimate sale transactions, the amounts of which could have a significant impact on our future recorded tax amounts and our effective tax rates in those periods.

We have a number of pending IRS Audits and income tax contingencies that are in various stages of completion as further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 7. We have provided reserves on these matters that are based on our best estimate of the ultimate outcome of each matter. As these audits are finalized and as these contingencies are resolved, we will adjust our estimates, the impact of which could have a material effect on the recorded amount of income taxes and our effective tax rates in those periods.

### Discontinued Operations

Our loss from discontinued operations for 2003 has been restated. For a further discussion see Part II, Item 8, Financial Statements and Supplementary Data, Note 1.

For the year ended December 2004, the loss from our discontinued operations was $146 million compared to a loss of $1,314 million during 2003. In 2004, $76 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from losses on sales and impairment charges, and $70 million was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. The losses in 2003 related primarily to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of our decision to exit and sell these businesses and ceiling test charges related to our Canadian production operations. The loss in 2002 was primarily due to operating losses at our Aruba refinery, impairment charges on our MTBE chemical plant and coal mining operations, and ceiling test charges related to our Canadian production operations.

## Commitments and Contingencies

For a discussion of our commitments and contingencies, see Part II, Item 8, Financial Statements and Supplementary Data, Note 17, incorporated herein by reference.

## Critical Accounting Policies

Our critical accounting policies are those accounting policies that involve the use of complicated processes, assumptions and/or judgments in the preparation of our financial statements. We have discussed the development and selection of our critical accounting policies and related disclosures with the audit committee of our Board of Directors and have identified the following critical accounting policies for the current year.

*Price Risk Management Activities.* We record the derivative instruments used in our price risk management activities at their fair values in our balance sheet. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary assumptions used to estimate the fair value of our derivative instruments is pricing. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from immediate selected potential changes in quoted market prices:

| | | 10 Percent Increase | | 10 Percent Decrease | |
|---|---|---|---|---|---|
| | **Fair Value** | **Fair Value** | **Change** | **Fair Value** | **Change** |
| Derivatives designated as hedges | $(536) | $(672) | $(136) | $(400) | $136 |
| Other commodity-based derivatives | (61) | (84) | (23) | (24) | 37 |
| Total | $(597) | $(756) | $(159) | $(424) | $173 |

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to time value, anticipated market liquidity and credit risk of our counterparties. The assumptions and methodologies that we use to determine the fair values of our derivatives may differ from those used by our derivative counterparties. These differences can be significant and could impact our future operating results as we settle these derivative positions.

*Accounting for Natural Gas and Oil Producing Activities.* Natural gas and oil reserves estimates underlie many of the accounting estimates in our financial statements as further discussed below. The process of estimating natural gas and oil reserves, particularly proved undeveloped and proved non-producing reserves, is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. Accordingly, our reserve estimates are developed internally by a reserve reporting group separate from our operations group and reviewed by internal committees and internal auditors. In addition, a third party engineering firm which is appointed by, and reports to the Audit Committee of our Board of Directors prepares an independent estimate of a significant portion of our proved reserves. As of December 31, 2004, of our total proved reserves, 29 percent were undeveloped and 13 percent were developed, but non-producing. In addition, the data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates.

The estimates of proved natural gas and oil reserves primarily impact our property, plant and equipment amounts in our balance sheets and the depreciation, depletion and amortization amounts in our income statements, among other items. We use the full cost method to account for our natural gas and oil producing activities. Under this accounting method, we capitalize substantially all of the costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves in full cost pools maintained by geographic areas, regardless of whether reserves are actually discovered. We record depletion expense of these capitalized amounts over the life of our proved reserves based on the unit of production method and, if all other factors are held constant, a 10 percent increase in estimated proved reserves would decrease our unit of production depletion rate by 9 percent and a 10 percent decrease in estimated proved reserves would increase our unit of depletion rate by 11 percent.

Under the full cost accounting method, we are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This impairment test is referred to as a ceiling test. Our total capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues from proved reserves using end of period spot prices and, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. Our ceiling test calculations include the effect of derivative instruments we have designated as, and that qualify as hedges of our anticipated natural gas and oil production. As a result, higher proved reserves can reduce the likelihood of ceiling test impairments. We recorded ceiling test charges in our continuing and discontinued operations of $35 million, $76 million and $128 million during 2004, 2003 and 2002.

The ceiling test calculation assumes that the price in effect on the last day of the quarter is held constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. A decline in commodity prices can impact the results of our ceiling test and may result in writedowns. A decrease in commodity prices of 10 percent from the price levels at December 31, 2004 would not have resulted in a ceiling test charge in 2004.

*Asset Impairments.* The asset impairment accounting rules require us to continually monitor our businesses and the business environment to determine if an event has occurred indicating that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then assess the expected future cash flows against which to compare the carrying value of the asset group being evaluated, a process which also involves judgment. We ultimately arrive at the fair value of the asset which is determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset). The assessment of project level cash flows requires us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our impairment estimates. We recorded impairments of our long-lived assets of $1.1 billion, $791 million and $440 million during the years ended December 31, 2004, 2003 and 2002 and impairments on our unconsolidated affiliates of $397 million, $449 million, and $566 million during the years ended December 31, 2004, 2003 and 2002. We recorded impairments of our discontinued operations of $9 million, $1.5 billion and $290 million during the years ended December 31, 2004, 2003 and 2002. Future changes in the economic and business environment can impact our assessments of potential impairments.

*Accounting for Environmental Reserves.* We accrue environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. 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 societal and economic factors, and include estimates of associated onsite, offsite and groundwater technical studies, and legal costs. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each exposure.

As of December 31, 2004, we had accrued approximately $380 million for environmental matters. Our reserve estimates range from approximately $380 million to approximately $547 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($82 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($298 million to $465 million) and the lower end of the range has been accrued.

*Accounting for Pension and Other Postretirement Benefits.* As of December 31, 2004, we had a $956 million pension asset and a $274 million other postretirement benefit liability reflected in other assets and liabilities in our balance sheet related to our pension and other postretirement benefit plans. These amounts are primarily based on actuarial calculations. These calculations include assumptions, including those related to the return that we expect to earn on our plan assets, discount rates used in calculating benefit obligations, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plans and other factors.

Actual results may differ from the assumptions included in these calculations, and as a result our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations are generally deferred and amortized into income over the life of the plans. The cumulative amount deferred as of December 31, 2004 is recorded as an $800 million increase in our pension asset and a $32 million reduction of our other postretirement liability. The following table shows the impact of a one percent change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2004 (in millions):

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | Net Benefit Expense (Income) | Projected Benefit Obligation | Net Benefit Expense (Income) | Accumulated Postretirement Benefit Obligation |
| One percent increase in: | | | | |
| Discount rates | $(13) | $(197) | $— | $(37) |
| Expected return on plan assets | (22) | — | (1) | — |
| Rate of compensation increase | 2 | 4 | — | — |
| Health care cost trends | — | — | 1 | 19 |
| One percent decrease in: | | | | |
| Discount rates | $ 15 | $ 236 | $— | $ 40 |
| Expected return on plan assets[(1)] | 22 | — | 1 | — |
| Rate of compensation increase | (1) | (4) | — | — |
| Health care cost trends | — | — | (1) | (18) |

(1) If the actual return on plan assets was one percent lower than the expected return on plan assets, our expected cash contributions to our pension and other postretirement benefit plans would not significantly change.

Our discount rate assumptions reflect the rates of return on the investments we expect to use to settle our pension and other postretirement obligations in the future. We combined current and expected rates of return on investment grade corporate bonds to develop the discount rates used in our benefit expense and obligation estimates as of September 30, 2004.

Our estimates for our net benefit expense (income) are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred and recognized over three years. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit expense would have been $14 million higher for the year ended December 31, 2004.

We have not recorded an additional pension liability for our primary pension plan because the fair value of assets of that plan exceeded the accumulated benefit obligation of that plan by approximately $262 million and $366 million as of September 30, 2004 and December 31, 2004. If the accumulated benefit obligation exceeded plan assets under this primary pension plan as of September 30, 2004, we would have recorded a pre-tax additional pension liability of approximately $960 million, plus an amount equal to the excess of the accumulated benefit obligation over plan assets of that plan. We would have also recorded an amount equal to this additional pension liability to accumulated other comprehensive loss, net of taxes, in our balance sheet.

### New Accounting Pronouncements Issued But Not Yet Adopted

See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 under *New Accounting Pronouncements Issued But Not Yet Adopted* which is incorporated herein by reference.

## RISK FACTORS AND 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.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the SEC from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

### Risks Related to Our Business

***Our operations are subject to operational hazards and uninsured risks.***

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

***The success of our pipeline business depends, in part, on factors beyond our control.***

Most of the natural gas and natural gas liquids we transport and store are owned by third parties. As a result, the volume of natural gas and natural gas liquids involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire, or to remarket unsubscribed capacity on our pipeline systems:

- service area competition;
- expiration and/or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- future weather conditions;
- price competition;
- drilling activity and availability of natural gas supplies;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- increased availability or popularity of alternative energy sources such as hydroelectric power;

- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands, and
- unfavorable movements in natural gas and liquids prices.

***The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.***

Substantially all of our pipeline subsidiaries' revenues are generated under contracts which expire periodically and must be renegotiated and extended or replaced. We cannot assure that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by our interstate pipelines;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues, earnings and cash flows.

***Fluctuations in energy commodity prices could adversely affect our pipeline businesses.***

Revenues generated by our transmission, storage, and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. Increased prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas-fired power plants. Increased prices could also result from industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies' loss of customer base. We also experience earnings volatility when the amount of gas utilized in operations differs from amounts we receive for that purpose. The success of our transmission, storage and processing operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional suppliers from interconnecting pipelines to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, storage and processing through our systems or facilities. We retain a fixed percentage of natural gas transported for use as fuel and to replace lost and unaccounted for gas, and we are at risk for the difference between the retained amount and actual gas consumed or lost and unaccounted. Pricing volatility may also impact the value of under or over recoveries of this retained gas. If natural gas prices in the supply basins connected to our pipeline systems are higher on a delivered basis to our off-system markets than delivered prices from other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

***Natural gas and oil prices are volatile. A substantial decrease in natural gas and oil prices could adversely affect the financial results of our exploration and production business.***

Our future financial condition, revenues, results of operations, cash flows and future rate of growth depend primarily upon the prices we receive for our natural gas and oil production. Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current world geopolitical conditions. The prices for natural gas and oil are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for, and the supply of, natural gas and oil;
- commodity processing, gathering and transportation availability;
- the level of imports of, and the price of, foreign natural gas and oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- the availability of pipeline capacity;
- weather conditions;
- market uncertainty;
- political conditions or hostilities in natural gas and oil producing regions;
- worldwide economic conditions; and
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives.

Further, because approximately 82 percent of our proved reserves at December 31, 2004 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices than we are to changes in oil prices. Declines in natural gas and oil prices would not only reduce revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could adversely affect the financial results of our production business. Changes in natural gas and oil prices can have a significant impact on the calculation of our full cost ceiling test. A significant decline in natural gas and oil prices could result in a downward revision of our reserves and a write-down of the carrying value of our natural gas and oil properties, which could be substantial, and would negatively impact our net income and stockholders' equity.

***The success of our natural gas and oil exploration and production businesses is dependent, in part, on factors that are beyond our control.***

In addition to prices, the performance of our natural gas and oil exploration and production businesses is dependent, in part, upon a number of factors that we cannot control, including:

- the results of future drilling activity;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;
- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive conditions;
- increased competition in the search for and acquisition of reserves;
- future drilling, production and development costs, including drilling rig rates and oil field services costs;
- future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;
- increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives;
- declines in production volumes, including those from the Gulf of Mexico; and
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

***Our natural gas and oil drilling and producing operations involve many risks and may not be profitable.***

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks. The nature of the risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured. As a result, we could incur substantial costs that could adversely affect our future results of operations, cash flows or financial condition.

In addition, in our drilling operations we are subject to the risk that we will not encounter commercially productive reservoirs. New wells drilled by us may not be productive, or we may not recover all or any portion of our investment in those wells. Drilling for natural gas and oil can be unprofitable, not only because of dry holes but wells that are productive may not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs.

***Estimating our reserves, production and future net cash flow is difficult.***

Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. As a result, our reserve estimates are inherently imprecise. Also, the use of a 10 percent discount factor for estimating the value of our reserves, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our production business or the natural gas and oil industry, in general, are subject. Any significant variations from the interpretations or assumptions used in our estimates or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially.

Our reserve data represents an estimate. You should not assume that the present values referred to in this report represent the current market value of our estimated natural gas and oil reserves. The timing of the production and the expenses from development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Changes in the present value of these reserves could cause a write-down in the carrying value of our natural gas and oil properties, which could be substantial, and would negatively affect our net income and stockholders' equity.

As of December 31, 2004, approximately 29 percent of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

***The success of our power activities depends, in part, on many factors beyond our control.***

The success of our remaining domestic and international power projects could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- increases in the costs of generation, including increases in fuel costs;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the United States and in foreign jurisdictions;
- our ability to negotiate successfully, and enter into advantageous power purchase and supply agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions, excessive reserve margins and the implementation of conservation programs;
- risks incidental to the operation and maintenance of power generation facilities;
- the inability of customers to pay amounts owed under power purchase agreements;
- the increasing price volatility due to deregulation and changes in commodity trading practices; and
- over-capacity of generation in markets served by the power plants we own or in which we have an interest.

***Our use of derivative financial instruments could result in financial losses.***

Some of our subsidiaries use futures, swaps and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. To the extent we have positions that are not designated or qualify as hedges, changes in commodity prices, interest rates, volatility, correlation factors, the liquidity of the market could cause our revenues, net income and cash requirements to be volatile.

We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments involves estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices were to increase, or interest rates were to change. The use of derivatives also requires the posting of cash collateral with our counterparties which can impact our working capital (current assets and liabilities) when commodity prices or interest rates change. For additional information concerning our derivative financial instruments, see Item 7A, Quantitative and Qualitative Disclosures About Market Risk and Part II, Item 8, Financial Statements and Supplementary Data, Note 10.

***Our businesses are subject to the risk of payment defaults by our counterparties.***

We frequently extend credit to our counterparties following the performance of credit analysis. Despite performing this analysis, we are exposed to the risk that we may not be able to collect amounts owed to us. Although in many cases we have collateral to secure the counterparty's performance, it could be inadequate and we could suffer credit losses.

***Our foreign operations and investments involve special risks.***

Our activities in areas outside the United States, including material investment exposure in our power, pipeline and production projects in Brazil and Pakistan, are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems; and
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties.

***Retained liabilities associated with businesses that we have sold could exceed our estimates.***

We have sold a significant number of assets over the years, including the sale of many assets since 2001. Pursuant to various purchase and sale agreements relating to businesses and assets that we have divested, we have either retained certain liabilities or indemnified certain purchasers against liabilities that they might incur in the future. These liabilities in many cases relate to breaches of warranties, environmental, tax, litigation, personal injury and other representations that we have provided. Although we believe that we have established appropriate reserves for these liabilities, we could be required to accrue additional reserves in the future and these amounts could be material. In addition, as we exit businesses, we have experienced substantial reductions and turnover in our workforce that previously supported the ownership and operation of such assets. There is the risk that such reductions and turnover in our workforce could result in errors or mistakes in managing the businesses that we are exiting prior to closing. There is also the risk that such reductions could result in errors or mistakes in managing the retained liabilities after closing, including the lack of any historical knowledge with regard to such assets and businesses in managing the liabilities or defending any associated litigation.

## Risks Related to Legal and Regulatory Matters

***Ongoing litigation and investigations related to our financial statements associated with our reserve estimates and hedges could significantly adversely affect our business.***

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves and because of the manner in which we applied the accounting rules related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. As a result of this reduction in reserve estimates, several class action lawsuits were filed against us and several of our subsidiaries. The reserve revisions are also the subject of investigations by the SEC and the U.S. Attorney and the hedging matters are also the subject of an investigation by the U.S. Attorney and may become the subject of a separate inquiry by the SEC, any of which could result in significant fines against us. These investigations and lawsuits, and possible future claims based on these same facts, may further negatively impact our credit ratings and place further demands on our liquidity. We cannot provide assurance at this time that the effects and results of these or other investigations or of the class action lawsuits will not be material to our financial conditions, results of operations and liquidity.

***The agencies that regulate our pipeline businesses and their customers affect our profitability.***

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. In setting authorized rates of return in a few recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risks as interstate pipelines. The inclusion of these companies creates downward pressure on approved tariff rates. If our pipelines' tariff rates were reduced in a future proceeding, if our pipelines' volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition or because of regulatory pressure, the profitability of our pipeline businesses could be reduced.

In addition, increased regulatory requirements relating to the integrity of our pipelines requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures.

Further, state agencies that regulate our pipelines' local distribution company customers could impose requirements that could impact demand for our pipelines' services.

***Costs of environmental liabilities, regulations and litigation could exceed our estimates.***

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. Some of these sites have been designated as Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

Compliance with environmental laws and regulations can require significant costs, such as costs of clean-up and damages arising out of contaminated properties, and the failure to comply with environmental laws and regulations may result in fines and penalties being imposed. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating pollution control and clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- potential changes in environmental laws and regulations, including changes in the interpretation and enforcement thereof.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties, and these amounts could be material. For additional information concerning our environmental matters, see Part I, Item 3, Legal Proceedings, and Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

***Costs of litigation matters and other contingencies could exceed our estimates.***

We are involved in various lawsuits in which we or our subsidiaries have been sued. We also have other contingent liabilities and exposures. Although we believe we have established appropriate reserves for these liabilities, we could be required to set aside additional reserves in the future and these amounts could be material. For additional information concerning our litigation matters and other contingent liabilities, see Part I, Item 8, Financial Statements and Supplementary Data, Note 17.

***Our system of internal controls ensure the accuracy or completeness of our disclosures and a loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.***

Section 404 of the Sarbanes-Oxley Act of 2002, requires us to provide an annual report on our internal controls over financial reporting, including an assessment as to whether or not our internal controls over financial reporting are effective. We are also required to have our auditors attest to our assessment and to opine on the effectiveness of our internal controls over financial reporting. Based upon such review, we concluded that as of December 31, 2004 we did not maintain effective internal control over financial reporting. As more fully discussed in Item 9A, we identified several deficiencies in internal control over financial reporting that management has concluded constitute material weaknesses. Although we have taken steps to remediate some of these deficiencies, additional steps must be taken to remediate the remaining control deficiencies. If we are unable to remediate our identified internal control deficiencies over financial reporting by the end of 2005, or we identify additional deficiencies in our internal controls over financial reporting, we could be subjected to additional regulatory scrutiny, future delays in filing our financial statements and suffer a loss of public confidence in the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, which could have a negative impact on our liquidity, access to capital markets, financial condition and the market value of our common stock.

In addition to the risk of not completing the remediation of all deficiencies in our internal controls over financial reporting, we do not expect that our disclosure controls and procedures or our internal controls over financial reporting will prevent all mistakes, errors and fraud. Any system of internal controls, no matter how well designed or implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that the benefits of controls must be considered relative to their costs. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Therefore, any system of internal controls is subject to inherent limitations, including the possibility that controls may be circumvented or overridden, that judgments in decision-making can be faulty, and that misstatements due to mistakes, errors or fraud may occur and may not be detected. Also, while we document our assumptions and review financial disclosures with the Audit Committee of our Board of Directors, the regulations and literature governing our disclosures are complex and reasonable persons may disagree as to their application to a particular situation or set of facts. In addition, the applicable regulations and literature are relatively new. As a result, they are potentially subject to change in the future, which could include changes in the interpretation of the existing regulations and literature as well as the issuance of more detailed rules and procedures.

## Risks Related to Our Liquidity

***We have significant debt and below investment grade credit ratings, which have impacted and will continue to impact our financial condition, results of operations and liquidity.***

We have significant debt of approximately $19 billion as of December 31, 2004 and have significant debt service and debt maturity obligations. The ratings assigned to our senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody's Investor Service (Moody's) and CCC+ by Standard & Poor's. These ratings have increased our cost of capital and our operating costs, particularly in our trading operations, and could impede our access to capital markets. Moreover, we must retain greater liquidity levels to operate our business than if we had investment grade credit ratings. Our debt maturities as of December 31, 2004 for 2005, 2006 and 2007 are $948 million, $1,155 million and $835 million, respectively. If our ability to generate or access capital becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 15, for a further discussion of our debt.

***We may not achieve all of the objectives set forth in our Long-Range Plan in a timely manner or at all.***

Our ability to achieve the objectives of our Long-Range Plan, as well as the timing of their achievement, if at all, is subject, in part, to factors beyond our control. These factors include (1) our ability to raise cash from asset sales, which may be impacted by our ability to locate potential buyers in a timely fashion and obtain a reasonable price, (2) our ability to manage our working capital, (3) our ability to generate additional cash by improving the performance of our pipeline and production operations, (4) our ability to exit the power and trading businesses in the manner and within the time period we expect, (5) our ability to significantly reduce debt, and (6) our ability to preserve sufficient cash flow to service our debt and other obligations. If we fail to achieve in a timely manner the targets of our Long-Range Plan, our liquidity or financial position could be materially adversely affected. In addition, it is possible that any of the asset sales contemplated by our Long-Range Plan could be at prices that are below our current book value for the assets, which could result in losses that could be substantial.

***A breach of the covenants applicable to our debt and other financing obligations could affect our ability to borrow funds and could accelerate our debt and other financing obligations and those of our subsidiaries.***

Our debt and other financing obligations contain restrictive covenants and cross-acceleration provisions, which become more restrictive over time. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit and from borrowing under our $3 billion credit agreement, and could accelerate our long-term debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

Our $3 billion credit agreement is collateralized by our equity interests in TGP, ANR, EPNG, CIG, WIC, Southern Gas Storage Company and ANR Storage Company. A breach of the covenants under the $3 billion agreement could permit the lender to exercise their rights to the collateral, and we could be required to liquidate these interests.

***Our ability to access capital markets is limited to private placements or filing new registration statements as a result of the restatement of our historical financial results.***

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves and because of the manner in which we applied the accounting rules related to our hedges of our natural gas production and certain other derivatives. As a result of the time required to complete these revisions, our 2003 Form 10-K and our 2004 Forms 10-Q were not filed in a timely manner. As a result, until January 2006, our ability to access approximately $926 million of capacity under our existing shelf registration statement without filing additional disclosure information with the SEC is restricted. The additional disclosure requirements, and any related review by the SEC, could be expensive and impede our ability to access capital in a timely fashion. If our ability to access capital becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected.

***We are subject to financing and interest rate exposure risks.***

Our future success depends on our ability to access capital markets and obtain financing at cost effective rates. Our ability to access financial markets and obtain cost-effective rates in the future are dependent on a number of factors, many of which we cannot control, including changes in:

- our credit ratings;
- interest rates;
- the structured and commercial financial markets;
- market perceptions of us or the natural gas and energy industry;
- changes in tax rates due to new tax laws;
- our stock price; and
- changes in market prices for energy.

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

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

- Commodity Price Risk
  - Natural gas prices change, impacting the forecasted sale of natural gas in our Production segment;
  - Price spreads between natural gas and natural gas liquids change, making the natural gas liquids we produce in our Field Services segment less valuable;
  - Locational price differences in natural gas change, affecting our ability to optimize pipeline transportation capacity contracts held in our Marketing and Trading segment; and
  - Electricity and natural gas prices change, affecting the value of our natural gas contracts, power contracts and tolling contracts held in our Marketing and Trading and Power segments.
- Interest Rate Risk
  - Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed-rate debt; and
  - Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions.
- Foreign Currency Exchange Rate Risk
  - Weakening or strengthening of the U.S. dollar relative to the Euro can result in an increase or decrease in the value of our Euro-denominated debt obligations and the related interest costs associated with that debt; and
  - Changes in foreign currencies exchange rates where we have international investments may impact the value of those investments and the earnings and cash flows from those investments.

We manage these risks by frequently entering into contractual commitments involving physical or financial settlement that attempts to limit the amount of risk or opportunity related to future market movements. Our risk management activities typically involve the use of the following types of contracts:

- Forward contracts, which commit us to purchase or sell energy commodities in the future, involving the physical delivery of an energy commodity, and energy related contracts including transportation, storage, transmission and power tolling arrangements;
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement at a specific price and future date;
- Options, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;
- Swaps, which require payments to or from counterparties based upon the differential between two prices for a predetermined contractual (notional) quantity; and
- Structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we utilize in our risk management activities are derivative financial instruments. A discussion of our accounting policies for derivative instruments are included in Part II, Item 8, Financial Statements and Supplementary Data, Notes 1 and 10.

### Commodity Price Risk

We are exposed to a variety of commodity price risks in the normal course of our business activities. The nature of these market price risks varies by segment.

### *Marketing and Trading*

Our Marketing and Trading segment attempts to mitigate its exposure to commodity price risk through the use of various financial instruments, including forwards, swaps, options and futures. We measure risks from our Marketing and Trading segment's commodity and energy-related contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to adverse market movements over a defined period of time within a specified confidence level, and monitors our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio's sensitivity to its underlying risks.

Our maximum expected one-day unfavorable impact on the fair values of our commodity and energy-related contracts as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $16 million and $34 million as of December 31, 2004 and 2003. Our highest, lowest and average of the month end values for Value-at-Risk during 2004 was $82 million, $16 million and $38 million. Actual losses in fair value may exceed those measured by Value-at-Risk. Our Value-at-Risk decreased during the fourth quarter of 2004 with the designation of a number of our natural gas derivative contracts as hedges of our Production segment's natural gas production. The exposure of these derivatives to natural gas price fluctuations is now captured in the Production segment discussion below.

### *Production*

Our Production segment attempts to mitigate commodity price risk and to stabilize cash flows associated with its forecasted sales of our natural gas and oil production through the use of derivative natural gas and oil swap contracts. 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, 2004 and 2003. 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. These derivatives do not hedge all of our commodity price risk related to our forecasted sales of our natural gas and oil production and as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

| | | 10 Percent Increase | | 10 Percent Decrease | |
|---|---|---|---|---|---|
| | Fair Value | Fair Value | (Change) | Fair Value | Increase |
| | | (In millions) | | | |
| Impact of changes in commodity prices on derivative commodity instruments | | | | | |
| December 31, 2004 | $(557) | $(697) | $(140) | $(417) | $140 |
| December 31, 2003 | $ (45) | $ (60) | $ (15) | $ (30) | $ 15 |

During the fourth quarter of 2004, we designated a number of our Marketing and Trading segment's natural gas derivative contracts as hedges of our Production segment's natural gas production. As a result, the sensitivity of the derivatives in our Production segment to natural gas price changes increased and our Marketing and Trading segment's Value-at-Risk decreased as of December 31, 2004 as discussed above.

Additionally, as of December 31, 2004, our Marketing and Trading segment has entered into derivative contracts designed to provide El Paso with price protection from declines in natural gas prices in 2005 and 2006. These contracts provide us with a floor price of $6.00 per MMBtu on 60 TBtu of our natural gas production in 2005 and 120 TBtu in 2006. In the first quarter of 2005, we entered into additional contracts that provide El Paso with a floor price of $6.00 per MMBtu on 30 TBtu of our natural gas in 2007, and a ceiling price of $9.50 per MMBtu on 60 TBtu of our natural gas production in 2006. The commodity price risk associated with these contracts are not included in the sensitivity analysis, but rather are included in our Value-at-Risk calculation discussed above.

*Field Services*

Our Field Services segment does not significantly utilize financial instruments to mitigate our exposure to the natural gas liquids it retains in its processing operations since this exposure is not material to our overall operations.

## Interest Rate Risk

*Debt*

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average interest rates on our interest-bearing securities, by expected maturity dates and the fair values of those securities. As of December 31, 2004 and 2003, 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 securities has been estimated based on quoted market prices for the same or similar issues.

| | December 31, 2004 | | | | | | | | December 31, 2003 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Expected Fiscal Year of Maturity of Carrying Amounts | | | | | | | | | |
| | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter | Total | Fair Value | Carrying Amounts | Fair Value |
| | (Dollars in millions) | | | | | | | | | |
| **Liabilities:** | | | | | | | | | | |
| Short-term debt — fixed rate | $ 7 | | | | | | $ 7 | $ 8 | $ 8 | $ 8 |
| Average interest rate | 6.2% | | | | | | | | | |
| Long-term debt and other obligations, including current portion — fixed rate | $740 | $1,111 | $ 797 | $ 703 | $1,464 | $12,932 | $17,747 | $18,387 | $20,152 | $19,594 |
| Average interest rate | 8.2% | 6.7% | 7.3% | 7.5% | 6.1% | 7.6% | | | | |
| Long-term debt and other obligations, including current portion-variable rate | $197 | $ 33 | $ 27 | $ 20 | $1,165 | $ — | $ 1,442 | $ 1,442 | $ 1,572 | $ 1,572 |
| Average interest rate | 9.1% | 4.8% | 4.7% | 5.6% | 5.6% | — | | | | |

*Derivatives from Power Contract Restructuring Activities*

Derivatives associated with our power contract restructuring business of our Power segment are valued using estimated future market power prices and a discount rate that considers the appropriate U.S. Treasury rate plus a credit spread specific to the contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in value that can be realized in a current transaction between willing parties. Since September 30, 2002, in order to provide for market risk, we have not reflected the increase in value that would result from decreases in U.S. Treasury rates because we believe the resulting increase in the value of these non-trading derivatives could not be realized in a current transaction between willing parties. To the extent there is commodity price risk associated with these derivative contracts, it is included in our Value-at-Risk calculation discussed above, but our exposure to changes in interest rates and credit spreads has not been included in our Value-at-Risk calculation. Historically, our interest rate risk associated with these contracts primarily related to UCF and Cedar Brakes I and II. As a result of the sale of UCF in 2004 and our sale of Cedar Brakes I and II in March 2005, our sensitivity to interest rate changes on our remaining restructured power contract derivatives will be minimal.

## Foreign Currency Exchange Rate Risk

*Debt*

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2004, we have Euro-denominated debt with a principal amount of €1,050 million of which €550 million matures in 2006 and €500 million matures in 2009. As of December 31, 2004 and 2003, we had swaps that effectively converted €725 million and €625 million of debt into $766 million and $645 million. The remaining principal at December 31, 2004 and 2003 of €325 million and €425 million was subject to foreign currency exchange risk.

In March 2005, we repurchased approximately €528 million of our debt maturing in 2006. After this repurchase, our unhedged Euro-denominated debt that is subject to foreign currency exchange risk totaled €172 million. As a result, a hypothetical ten percent increase or decrease in the Euro/USD exchange rate of 1.3188 as of the date of repurchase, with all other variables held constant, would increase or decrease the carrying value of our remaining unhedged Euro-denominated debt after the repurchase by approximately $23 million.

*Power Contracts*

Several of our international power plants in Asia, Central America, South America and Europe have long-term power sales contracts that are denominated in the local country's currencies. As a result, we are subject to foreign currency exchange risk related to these power sales contracts. We do not believe that this exposure is material to our operations and have not chosen to mitigate this exposure.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### Index to Financial Statements and Related Reports

Below is an index to the financial statements and notes contained in Item 8, Financial Statements and Supplementary Data.

## EL PASO CORPORATION

## CONSOLIDATED STATEMENTS OF INCOME
**(In millions, except per common share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 (Restated) | 2002 (Restated) |
| Operating revenues | | | |
| Pipelines | $ 2,651 | $ 2,647 | $ 2,610 |
| Production | 1,735 | 2,141 | 1,931 |
| Marketing and Trading | (508) | (635) | (1,324) |
| Power | 795 | 1,176 | 1,672 |
| Field Services | 1,362 | 1,529 | 2,029 |
| Corporate and eliminations | (161) | (190) | (37) |
| | 5,874 | 6,668 | 6,881 |
| Operating expenses | | | |
| Cost of products and services | 1,363 | 1,818 | 2,468 |
| Operation and maintenance | 1,872 | 2,010 | 2,091 |
| Depreciation, depletion and amortization | 1,088 | 1,176 | 1,159 |
| Loss on long-lived assets | 1,092 | 860 | 181 |
| Western Energy Settlement | — | 104 | 899 |
| Taxes, other than income taxes | 253 | 295 | 254 |
| | 5,668 | 6,263 | 7,052 |
| Operating income (loss) | 206 | 405 | (171) |
| Earnings (losses) from unconsolidated affiliates | 559 | 363 | (214) |
| Other income | 189 | 203 | 197 |
| Other expenses | (99) | (202) | (239) |
| Interest and debt expense | (1,607) | (1,791) | (1,297) |
| Distributions on preferred interests of consolidated subsidiaries | (25) | (52) | (159) |
| Loss before income taxes | (777) | (1,074) | (1,883) |
| Income taxes | 25 | (469) | (641) |
| Loss from continuing operations | (802) | (605) | (1,242) |
| Discontinued operations, net of income taxes | (146) | (1,314) | (425) |
| Cumulative effect of accounting changes, net of income taxes | — | (9) | (208) |
| Net loss | $ (948) | $(1,928) | $(1,875) |
| Basic and diluted loss per common share | | | |
| Loss from continuing operations | $ (1.25) | $ (1.01) | $ (2.22) |
| Discontinued operations, net of income taxes | (0.23) | (2.20) | (0.76) |
| Cumulative effect of accounting changes, net of income taxes | — | (0.02) | (0.37) |
| Net loss | $ (1.48) | $ (3.23) | $ (3.35) |
| Basic and diluted average common shares outstanding | 639 | 597 | 560 |

See accompanying notes.

## EL PASO CORPORATION

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

| | December 31, 2004 | December 31, 2003 (Restated) |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 2,117 | $ 1,429 |
| Accounts and notes receivable | | |
| Customer, net of allowance of $199 in 2004 and $273 in 2003 | 1,388 | 2,039 |
| Affiliates | 133 | 189 |
| Other | 188 | 245 |
| Inventory | 168 | 181 |
| Assets from price risk management activities | 601 | 706 |
| Margin and other deposits held by others | 79 | 203 |
| Assets held for sale and from discontinued operations | 181 | 2,538 |
| Restricted cash | 180 | 590 |
| Deferred income taxes | 418 | 592 |
| Other | 179 | 210 |
| Total current assets | 5,632 | 8,922 |
| Property, plant and equipment, at cost | | |
| Pipelines | 19,418 | 18,563 |
| Natural gas and oil properties, at full cost | 14,968 | 14,689 |
| Power facilities | 1,534 | 1,660 |
| Gathering and processing systems | 171 | 334 |
| Other | 882 | 998 |
| | 36,973 | 36,244 |
| Less accumulated depreciation, depletion and amortization | 18,161 | 18,049 |
| Total property, plant and equipment, net | 18,812 | 18,195 |
| Other assets | | |
| Investments in unconsolidated affiliates | 2,614 | 3,409 |
| Assets from price risk management activities | 1,584 | 2,338 |
| Goodwill and other intangible assets, net | 428 | 1,082 |
| Other | 2,313 | 2,996 |
| | 6,939 | 9,825 |
| Total assets | $31,383 | $36,942 |

See accompanying notes.

# EL PASO CORPORATION

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

| | December 31, 2004 | December 31, 2003 (Restated) |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $ 1,052 | $ 1,552 |
| Affiliates | 21 | 26 |
| Other | 483 | 438 |
| Short-term financing obligations, including current maturities | 955 | 1,457 |
| Liabilities from price risk management activities | 852 | 734 |
| Western Energy Settlement | 44 | 633 |
| Liabilities related to assets held for sale and discontinued operations | 12 | 933 |
| Accrued interest | 333 | 391 |
| Other | 820 | 910 |
| Total current liabilities | 4,572 | 7,074 |
| Long-term financing obligations, less current maturities | 18,241 | 20,275 |
| Other | | |
| Liabilities from price risk management activities | 1,026 | 781 |
| Deferred income taxes | 1,311 | 1,551 |
| Western Energy Settlement | 351 | 415 |
| Other | 2,076 | 2,047 |
| | 4,764 | 4,794 |
| Commitments and contingencies | | |
| Securities of subsidiaries | | |
| Securities of consolidated subsidiaries | 367 | 447 |
| Stockholders' equity | | |
| Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 651,064,508 shares in 2004 and 639,299,156 shares in 2003 | 1,953 | 1,917 |
| Additional paid-in capital | 4,538 | 4,576 |
| Accumulated deficit | (2,855) | (1,907) |
| Accumulated other comprehensive income | 48 | 11 |
| Treasury stock (at cost); 7,767,088 shares in 2004 and 7,097,326 shares in 2003 | (225) | (222) |
| Unamortized compensation | (20) | (23) |
| Total stockholders' equity | 3,439 | 4,352 |
| Total liabilities and stockholders' equity | $31,383 | $36,942 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 (Restated)[1] | 2002 (Restated)[1] |
| Cash flows from operating activities | | | |
| Net loss | $ (948) | $(1,928) | $(1,875) |
| Less loss from discontinued operations, net of income taxes | (146) | (1,314) | (425) |
| Net loss before discontinued operations | (802) | (614) | (1,450) |
| Adjustments to reconcile net loss to net cash from operating activities | | | |
| Depreciation, depletion and amortization | 1,088 | 1,176 | 1,159 |
| Western Energy Settlement | — | 94 | 899 |
| Deferred income tax benefit | (38) | (604) | (685) |
| Cumulative effect of accounting changes | — | 9 | 208 |
| Loss on long-lived assets | 1,092 | 785 | 181 |
| Losses (earnings) from unconsolidated affiliates, adjusted for cash distributions | (224) | (17) | 521 |
| Other non-cash income items | 451 | 399 | 255 |
| Asset and liability changes | | | |
| Accounts and notes receivable | 471 | 2,552 | (629) |
| Inventory | 9 | 76 | 248 |
| Change in non-hedging price risk management activities, net | 191 | 85 | 1,074 |
| Accounts payable | (295) | (2,127) | (114) |
| Broker and other margins on deposit with others | 121 | 623 | (257) |
| Broker and other margins on deposit with us | (24) | 32 | (647) |
| Western Energy Settlement liability | (626) | — | — |
| Other asset and liability changes | | | |
| Assets | (20) | (267) | 54 |
| Liabilities | (301) | 102 | (139) |
| Cash provided by continuing activities | 1,093 | 2,304 | 678 |
| Cash provided by (used in) discontinued activities | 223 | 25 | (242) |
| Net cash provided by operating activities | 1,316 | 2,329 | 436 |
| Cash flows from investing activities | | | |
| Additions to property, plant and equipment | (1,782) | (2,328) | (3,243) |
| Purchases of interests in equity investments | (34) | (33) | (299) |
| Cash paid for acquisitions, net of cash acquired | (47) | (1,078) | 45 |
| Net proceeds from the sale of assets and investments | 1,927 | 2,458 | 2,779 |
| Net change in restricted cash | 578 | (534) | (260) |
| Net change in notes receivable from affiliates | 120 | (43) | 4 |
| Other | (1) | — | 22 |
| Cash provided by (used in) continuing activities | 761 | (1,558) | (952) |
| Cash provided by (used in) discontinued activities | 1,142 | 369 | (303) |
| Net cash provided by (used in) investing activities | 1,903 | (1,189) | (1,255) |

(1) Only individual line items in cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

## EL PASO CORPORATION

### CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
### (In millions)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 (Restated) [(1)] | 2002 (Restated) [(1)] |
| Cash flows from financing activities | | | |
| Net proceeds from issuance of long-term debt | 1,300 | 3,633 | 4,294 |
| Payments to retire long-term debt and other financing obligations | (2,306) | (2,824) | (1,777) |
| Net borrowings/(repayments) under revolving and other short-term credit facilities | (850) | (650) | 154 |
| Net proceeds from issuance of notes payable | — | 84 | — |
| Repayment of notes payable | (214) | (8) | (94) |
| Payments to minority interest and preferred interest holders | (35) | (1,277) | (861) |
| Issuances of common stock | 73 | 120 | 1,053 |
| Dividends paid | (101) | (203) | (470) |
| Other | (33) | (177) | (476) |
| Contributions from (distributions to) discontinued operations | 1,000 | 394 | (1,106) |
| Cash provided by (used in) continuing activities | (1,166) | (908) | 717 |
| Cash provided by (used in) discontinued activities | (1,365) | (394) | 555 |
| Net cash provided by (used in) financing activities | (2,531) | (1,302) | 1,272 |
| Change in cash and cash equivalents | 688 | (162) | 453 |
| Less change in cash and cash equivalents related to discontinued operations | — | — | 10 |
| Change in cash and cash equivalents from continuing operations | 688 | (162) | 443 |
| Cash and cash equivalents | | | |
| Beginning of period | 1,429 | 1,591 | 1,148 |
| End of period | $ 2,117 | $ 1,429 | $ 1,591 |
| | | | |
| Supplemental Cash Flow Information: | | | |
| Interest paid, net of amounts capitalized | $ 1,536 | $ 1,657 | $ 1,291 |
| Income tax payments (refunds) | 68 | 23 | (106) |

(1) Only individual line items in cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

## EL PASO CORPORATION

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
**(In millions except for per share amounts)**

| | For the Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | 2003 | | 2002 | |
| | Shares | Amount | Shares | Amount | Shares | Amount |
| Common stock, $3.00 par: | | | | | | |
| Balance at beginning of year | 639 | $ 1,917 | 605 | $ 1,816 | 538 | $ 1,615 |
| Equity offering | — | — | — | — | 52 | 155 |
| Exchange of equity security units | — | — | 15 | 45 | — | — |
| Western Energy Settlement equity offerings | 9 | 26 | 18 | 53 | — | — |
| Other, net | 3 | 10 | 1 | 3 | 15 | 46 |
| Balance at end of year | 651 | 1,953 | 639 | 1,917 | 605 | 1,816 |
| Additional paid-in capital: | | | | | | |
| Balance at beginning of year | | 4,576 | | 4,444 | | 3,130 |
| Compensation related issuances | | 15 | | 8 | | 57 |
| Tax effects of equity plans | | 5 | | (26) | | 15 |
| Equity offering | | — | | — | | 846 |
| Exchange of equity security units | | — | | 189 | | — |
| Conversion of FELINE PRIDES[SM] | | — | | — | | 423 |
| Western Energy Settlement equity offerings | | 46 | | 67 | | — |
| Dividends ($0.16 per share) | | (104) | | (96) | | — |
| Other | | — | | (10) | | (27) |
| Balance at end of year | | 4,538 | | 4,576 | | 4,444 |
| Accumulated deficit (Restated): | | | | | | |
| Balance at beginning of year | | (1,907) | | 21 | | 2,387 |
| Net loss | | (948) | | (1,928) | | (1,875) |
| Dividends ($0.87 per share) | | — | | — | | (491) |
| Balance at end of year | | (2,855) | | (1,907) | | 21 |
| Accumulated other comprehensive income (loss): | | | | | | |
| Balance at beginning of year | | 11 | | (235) | | (18) |
| Other comprehensive income (loss) | | 37 | | 246 | | (217) |
| Balance at end of year | | 48 | | 11 | | (235) |
| Treasury stock, at cost: | | | | | | |
| Balance at beginning of year | (7) | (222) | (6) | (201) | (8) | (261) |
| Compensation related issuances | — | 9 | — | — | 3 | 79 |
| Other | (1) | (12) | (1) | (21) | (1) | (19) |
| Balance at end of year | (8) | (225) | (7) | (222) | (6) | (201) |
| Unamortized compensation: | | | | | | |
| Balance at beginning of year | | (23) | | (95) | | (187) |
| Issuance of restricted stock | | (28) | | (1) | | (36) |
| Amortization of restricted stock | | 23 | | 60 | | 73 |
| Forfeitures of restricted stock | | 9 | | 15 | | 15 |
| Other | | (1) | | (2) | | 40 |
| Balance at end of year | | (20) | | (23) | | (95) |
| Total stockholders' equity | 643 | $ 3,439 | 632 | $ 4,352 | 599 | $ 5,750 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 (Restated) |
| Net loss | $ (948) | $(1,928) | $(1,875) |
| Foreign currency translation adjustments (net of income tax of $10 in 2004) | 7 | 159 | (20) |
| Minimum pension liability accrual (net of income tax of $11 in 2004, $7 in 2003 and $20 in 2002) | (22) | 11 | (35) |
| Net gains (losses) from cash flow hedging activities: | | | |
| Unrealized mark-to-market gains (losses) arising during period (net of income tax of $8 in 2004, $50 in 2003 and $53 in 2002) | 22 | 101 | (90) |
| Reclassification adjustments for changes in initial value to settlement date (net of income tax of $8 in 2004, $11 in 2003 and $40 in 2002) | 30 | (25) | (73) |
| Other | — | — | 1 |
| Other comprehensive income (loss) | 37 | 246 | (217) |
| Comprehensive loss | $ (911) | $(1,682) | $(2,092) |

See accompanying notes.

## 1. Basis of Presentation and Significant Accounting Policies

*Basis of Presentation*

Our consolidated financial statements include the accounts of all majority-owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our results for all periods presented reflect our Canadian and certain other international natural gas and oil production operations, petroleum markets and coal mining businesses as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications did not impact our reported net loss or stockholders' equity.

*Restatements*

*Goodwill.* During the completion of the financial statements for the year ended December 31, 2004, we identified an error in the manner in which we had originally adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* in 2002. Upon adoption of these standards, we incorrectly adjusted the cost of investments in unconsolidated affiliates and the cumulative effect of change in accounting principle for the excess of our share of the affiliates' fair value of net assets over their original cost, which we believed was negative goodwill. The amount originally recorded as a cumulative effect of accounting change was $154 million and related to our investments in Citrus Corporation, Portland Natural Gas, several Australian investments and an investment in the Korea Independent Energy Corporation. We subsequently determined that the amounts we adjusted were not negative goodwill, but rather amounts that should have been allocated to the long-lived assets underlying our investments. As a result, we were required to restate our 2002 financial statements to reverse the amount we recorded as a cumulative effect of an accounting change on January 1, 2002. This adjustment also impacted a related deferred tax adjustment and an unrealized loss we recorded on our Australian investments during 2002, requiring a further restatement of that year. The restatements also affected the investment, deferred tax liability and stockholders' equity balances we reported as of December 31, 2002 and 2003. Below are the effects of our restatements:

| | For the Year Ended December 31, 2002 | |
|---|---|---|
| | As Reported | As Restated |
| | (In millions except per common share amounts) | |
| *Income Statement:* | | |
| Earnings (losses) from unconsolidated affiliates | $ (226) | $ (214) |
| Income taxes (benefit) | (621) | (641) |
| Cumulative effect of accounting changes, net of income taxes | (54) | (208) |
| Net loss | (1,753) | (1,875) |
| Basic and diluted net loss per share: | | |
| Cumulative effect of accounting changes, net of income taxes | (0.10) | (0.37) |
| Net loss | (3.13) | (3.35) |

| | As of December 31, | | | |
|---|---|---|---|---|
| | 2002 | | 2003 | |
| | As Reported | As Restated | As Reported | As Restated |
| *Balance Sheet:* | | | | |
| Investments in unconsolidated affiliates | $4,891 | $4,749 | $3,551 | $3,409 |
| Non-current deferred income tax liabilities | 2,094 | 2,074 | 1,571 | 1,551 |
| Stockholders' equity | 5,872 | 5,750 | 4,474 | 4,352 |

The restatement did not impact 2003 and 2004 reported income amounts, except that we recorded an adjustment related to these periods of $(19) million in the fourth quarter of 2004. The components of this adjustment were immaterial to all previously reported interim and annual periods.

*Income Taxes.* We also identified an error in the manner in which we had originally reported certain of our income taxes associated with our discontinued Canadian exploration and production operations for the year ended December 31, 2003. We incorrectly included approximately $82 million of deferred tax benefits in continuing operations in the fourth quarter of 2003 that should have been reflected in discontinued operations. As a result, we were required to restate our 2003 financial statements, and related quarterly financial information, to reclassify this amount from continuing operations to discontinued operations. We have also reflected the restatement amounts indicated below in Notes 7 and 21. This restatement did not impact our reported net loss, balance sheet amounts or cash flows as of and for the year ended December 31, 2003. Below are the effects of this restatement on our income statement:

| | For the Year Ended December 31, 2003 | |
|---|---|---|
| | As Reported | As Restated |
| | (In millions except per common share amounts) | |
| Income taxes | $ (551) | $ (469) |
| Loss from continuing operations | (523) | (605) |
| Discontinued operations, net of income taxes | (1,396) | (1,314) |
| Basic and diluted loss per share: | | |
| Loss from continuing operations | (0.87) | (1.01) |
| Discontinued operations, net of income taxes | (2.34) | (2.20) |

### *Principles of Consolidation*

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interests in that entity. The determination of our ability to control or exert significant influence over an entity and if we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the policies and decisions of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity. See Note 2 for a discussion of our adoption of an accounting standard that impacted our consolidation principles in 2004.

### *Use of Estimates*

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

### *Accounting for Regulated Operations*

Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Of our regulated pipelines, TGP, EPNG, SNG, CIG, WIC, CPG and MPC follow the regulatory accounting principles prescribed under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* ANR discontinued the application of SFAS No. 71 in 1996. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, postretirement employee benefit plans, and other costs included in, or expected to be included in, future rates. Effective December 31, 2004, ANR Storage began re-applying the provisions of SFAS No. 71.

We perform an annual review to assess the applicability of the provisions of SFAS No. 71 to our financial statements, the outcome of which could result in the re-application of this accounting in some of our regulated systems or the discontinuance of this accounting in others.

*Cash and Cash Equivalents*

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

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of December 31, 2004, we had $180 million of restricted cash in current assets, and $180 million in other non-current assets. As of December 31, 2003, we had $590 million of restricted cash in current assets and $349 million in other non-current assets. Of the 2003 amounts, $468 million was related to funds escrowed for our Western Energy Settlement discussed in Note 17.

*Allowance for Doubtful Accounts*

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

*Inventory*

Our inventory consists of spare parts, natural gas in storage, optic fiber and power turbines. We classify all inventory as current or non-current based on whether it will be sold or used in the normal operating cycle of the assets, to which it relates, which is typically within the next twelve months. We use the average cost method to account for our inventories. We value all inventory at the lower of its cost or market value.

*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. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates. The following table presents our property, plant and equipment by type, depreciation method and depreciable lives:

| Type | Method | Depreciable Lives (In years) |
|---|---|---|
| Regulated interstate systems | | |
| SFAS No. 71 | Composite[(1)] | 1-63 |
| Non-SFAS No. 71 | Composite[(1)] | 1-64 |
| Non-regulated systems | | |
| Transmission and storage facilities | Straight-line | 35 |
| Power facilities | Straight-line | 3-30 |
| Gathering and processing systems | Straight-line | 3-33 |
| Buildings and improvements | Straight-line | 5-40 |
| Office and miscellaneous equipment | Straight-line | 1-10 |

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

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

We capitalize a carrying cost on funds related to our construction of long-lived assets. This carrying cost consists of (i) an interest cost on our debt that could be attributed to the assets, which applies to all of our regulated transmission businesses and (ii) a return on our equity, that could be attributed to the assets, which only applies to regulated transmission businesses that apply SFAS No. 71. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized during the years ended December 31, 2004, 2003 and 2002, were $39 million, $31 million and $28 million. These amounts are included as a reduction of interest expense in our income statements. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized during the years ended December 31, 2004, 2003 and 2002 were $22 million, $19 million and $8 million. These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity-financed construction are reflected as an increase in the cost of the asset on our balance sheet.

*Asset and Investment Impairments*

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* and Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock,* to account for asset and investment impairments. Under these standards, we evaluate an asset or investment for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investment in unconsolidated affiliates. If an impairment is indicated or if we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors. We also reclassify the asset or assets as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have any continuing involvement in the cash flows of those assets after they are sold.

*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 costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. This method differs from the successful efforts method of accounting for these activities. The primary differences between these two methods are the treatment of exploratory dry hole costs. These costs are generally expensed under successful efforts when the determination is made that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is then periodically assessed for recoverability as discussed below.

We amortize capitalized costs using the unit of production method over the life of our proved reserves. Capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in the amortizable base. Beginning January 1, 2003, we began capitalizing asset retirement costs associated with proved developed natural gas and oil reserves into our full cost pool, pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations* as discussed below.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not greater than or equal to the 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 a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

When we sell or convey interests (including net profits interests) in our natural gas and oil properties, we reduce our reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or loss on sales of our natural gas and oil properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves. We treat sales proceeds on non-significant sales as an adjustment to the cost of our properties.

*Goodwill and Other Intangible Assets*

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. We apply SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets,* to account for these intangibles. Under these standards, goodwill and intangibles that have indefinite lives are not amortized, but instead are periodically tested for impairment, at least annually, and whenever an event occurs that indicates that an impairment may have occurred. We amortize all other intangible assets on a straight-line basis over their estimated useful lives.

The net carrying amounts of our goodwill as of December 31, 2004 and 2003, and the changes in the net carrying amounts of goodwill for the years ended December 31, 2004 and 2003 for each of our segments are as follows:

| | Pipelines | Field Services | Power | Corporate & Other | Total |
|---|---|---|---|---|---|
| | | | (In millions) | | |
| Balances as of January 1, 2003 | $413 | $483 | $ 3 | $205 | $1,104 |
| Additions to goodwill | — | — | 22 | — | 22 |
| Impairments of goodwill | — | — | (22) | (163) | (185) |
| Dispositions of goodwill | — | — | — | (42) | (42) |
| Other changes | — | (3) | — | — | (3) |
| Balances as of December 31, 2003 | 413 | 480 | 3 | — | 896 |
| Impairments of goodwill | — | (480) | — | — | (480) |
| Other changes | — | — | (3) | — | (3) |
| Balances as of December 31, 2004 | $413 | $ — | $— | $ — | $ 413 |

Our Field Services impairments resulted from the sale of substantially all of its interests in GulfTerra Energy Partners, as well as certain processing assets in our Field Services segment, to affiliates of Enterprise Products Partners L.P. As a result of these sales, we determined that the remaining assets in our Field Services segment could not support the goodwill in this segment. See Note 22 for a further discussion of the Enterprise transactions.

Our Power segment recorded $22 million of goodwill in May 2003 in connection with the acquisition of Chaparral. In December 2003, we determined that we would sell substantially all of Chaparral's power plants and, based on the bids received, we determined that this goodwill was not recoverable and we fully impaired this amount.

Our Corporate and Other impairments resulted from weak industry conditions in our telecommunications operations. We also disposed of $42 million of goodwill related to our financial services businesses in 2003, which we had previously impaired by $44 million in 2002 based on weak industry conditions and our decision not to invest further capital in those businesses.

In addition to our goodwill, we had a $181 million intangible asset as of December 31, 2003, related to our excess investment in our general partnership interest in GulfTerra. We disposed of this asset as a part of the Enterprise sales described above. We also had other intangible assets of $15 million and $5 million as of December 31, 2004 and 2003, primarily related to customer lists and other miscellaneous intangible assets.

*Pension and Other Postretirement Benefits*

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense related to these plans in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

We compare the benefits earned, or the accumulated benefit obligation, to the plan's fair value of assets on an annual basis. To the extent the plan's accumulated benefit obligation exceeds the fair value of plan assets, we record a minimum pension liability in our balance sheet equal to the difference in these two amounts. We do not record an additional minimum liability if it is less than the liability already accrued for the plan. If this difference is greater than the pension liability recorded on our balance sheet, however, we record an additional liability and an amount to other comprehensive loss, net of income taxes, on our financial statements.

In 2004, we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $49 million, which is deferred as an actuarial gain in our postretirement benefit liabilities as of December 31, 2004. We expect that the adoption of this guidance will reduce our postretirement benefit expense by approximately $6 million in 2005.

*Revenue Recognition*

Our business segments provide a number of services and sell a variety of products. Our revenue recognition policies by segment are as follows:

*Pipelines revenues.* Our Pipelines segment derives revenues primarily from transportation and storage services. We also derive revenue from sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity over the contract period regardless of the amount that is actually used. For interruptible or volumetric based services and for revenues under natural gas sales contracts, we record revenues when we complete the delivery of natural gas to the agreed upon delivery point and when natural gas is injected or withdrawn from the storage facility. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract or tariff. We are subject to FERC regulations and, as a result, revenues we collect may be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We establish reserves for these potential refunds.

*Production revenues.* Our Production segment derives revenues primarily through the physical sale of natural gas, oil, condensate and natural gas liquids. Revenues from sales of these products are recorded upon the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. When actual natural gas sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. Costs associated with the transportation and delivery of production are included in cost of sales.

*Field Services revenues.* Our Field Services segment derives revenues primarily from gathering and processing services and through the sale of commodities that are retained from providing these services. There are two general types of services: fee-based and make-whole. For fee-based services we recognize revenues at the time service is rendered based upon the volume of gas gathered, treated or processed at the contracted fee. For make-whole services, our fee consists of retainage of natural gas liquids and other by-products that are a result of processing, and we recognize revenues on these services at the time we sell these products, which generally coincides with when we provide the service.

*Power and Marketing and Trading revenues.* Our Power and Marketing and Trading segments derive revenues from physical sales of natural gas and power and the management of their derivative contracts. Our derivative transactions are recorded at their fair value, and changes in their fair value are reflected in operating revenues. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities*. Revenues on physical sales are recognized at the time the commodity is delivered and are based on the volumes delivered and the contractual or market price.

*Corporate.* Revenue producing activities in our corporate operations primarily consist of revenues from our telecommunications business. We recognize revenues for our metro transport, collocation and cross-connect services in the month that the services are actually used by the customer.

*Environmental Costs and Other Contingencies*

We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal or regulatory guidelines dictate otherwise. 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 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 or government sponsored 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*

Our price risk management activities consist of the following activities:

- derivatives entered into to hedge the commodity, interest rate and foreign currency exposures primarily on our natural gas and oil production and our long-term debt;
- derivatives related to our power contract restructuring business; and
- derivatives related to our trading activities that we historically entered into with the objective of generating profits from exposure to shifts or changes in market prices.

We account for all derivative instruments under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* Under SFAS No. 133, derivatives are reflected in our balance sheet at their fair value as assets and liabilities from price risk management activities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. See Note 10 for a further discussion of our price risk management activities.

Prior to 2002, we also accounted for other non-derivative contracts, such as transportation and storage capacity contracts and physical natural gas inventories and exchanges, that were used in our energy trading business at their fair values under Emerging Issues Task Force (EITF) Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* In 2002, we adopted EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involving Energy Trading and Risk Management Activities.* As a result, we adjusted the carrying value of these non-derivative instruments to zero and now account for them on an accrual basis of accounting. We also adjusted the physical natural gas inventories used in our historical trading business to their cost (which was lower than market) and our physical natural gas exchanges to their expected settlement amounts and reclassified these amounts to inventory and accounts receivable and payable on our balance sheet. Upon our adoption of EITF Issue No. 02-3, we recorded a net loss of $343 million ($222 million net of income taxes) as a cumulative effect of an accounting change in our income statement, of which $118 million was the net adjustment to our natural gas inventories and exchanges and $225 million which was the net adjustment for our other non-derivative instruments.

Our income statement treatment of changes in fair value and settlements of derivatives depends on the nature of the derivative instrument. Derivatives used in our hedging activities are reflected as either revenues or expenses in our income statements based on the nature and timing of the hedged transaction. Derivatives related to our power contract restructuring activities are reflected as either revenues (for settlements and changes in the fair values of the power sales contracts) or expenses (for settlements and changes in the fair values of the power supply agreements). The income statement presentation of our derivative contracts used in our historical energy trading activities is reported in revenue on a net basis (revenues net of the expenses of the physically settled purchases).

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables and payables in our balance sheet.

During 2002, we also adopted Derivatives Implementation Group (DIG) Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed-price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one of its fuel supply contract upon adoption of these new rules, and we recorded our proportionate share of this gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement.

*Income Taxes*

We record current income taxes based on our current taxable income, and we provide for deferred income taxes to reflect estimated future tax payments and receipts. Deferred taxes represent the tax impacts 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 recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

We maintain a tax accrual policy to record both regular and alternative minimum taxes for companies included in our consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. We pay all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, we may bill or refund our subsidiaries for their portion of these income tax payments.

*Foreign Currency Transactions and Translation*

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. These gains and losses were insignificant in 2004, 2003 and 2002. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component of other expense. For the years ended December 31, 2004, 2003 and 2002, we recorded net foreign currency losses of $17 million, $100 million and $91 million primarily related to currency losses on our Euro-denominated debt. The U.S. dollar is the functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and the translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholders' equity. The net cumulative currency translation gain recorded in accumulated other comprehensive income was $52 million and $45 million at December 31, 2004 and 2003. Revenues and expenses are translated at average exchange rates prevailing during the year.

*Treasury Stock*

We account for treasury stock using the cost method and report it in our balance sheet as a reduction to stockholders' equity. Treasury stock sold or issued is valued on a first-in, first-out basis. Included in treasury stock at both December 31, 2004, and 2003, were approximately 1.6 million shares and 1.7 million shares of common stock held in a trust under our deferred compensation programs.

*Stock-Based Compensation*

We account for our stock-based compensation plans using the intrinsic value method under the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. We have both fixed and variable compensation plans, and we account for these plans using fixed and variable accounting as appropriate. Compensation expense for variable plans, including restricted stock grants, is measured using the market price of the stock on the date the number of shares in the grant becomes determinable. This measured expense is amortized into income over the period of service in which the grant is earned. Our stock options are granted under a fixed plan at the market value on the date of grant. Accordingly, no compensation expense is recognized. Had we accounted for our stock-based compensation using SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the income (loss) and per share impacts on our financial statements would have been different. The following shows the impact on net loss and loss per share had we applied SFAS No. 123:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 (Restated) |
| | (In millions, except per common share amounts) | | |
| Net loss, as reported | $ (948) | $(1,928) | $(1,875) |
| Add: Stock-based employee compensation expense included in reported net loss, net of taxes | 14 | 38 | 47 |
| Deduct: Total stock-based employee compensation determined under fair value-based method for all awards, net of taxes | (35) | (88) | (169) |
| Pro forma net loss | $ (969) | $(1,978) | $(1,997) |
| Loss per share: | | | |
| Basic and diluted, as reported | $(1.48) | $ (3.23) | $ (3.35) |
| Basic and diluted, pro forma | $(1.52) | $ (3.31) | $ (3.57) |

*Accounting for Asset Retirement Obligations*

On January 1, 2003, we adopted SFAS No. 143, which requires that we record a liability for retirement and removal costs of long-lived assets used in our business. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times, generally over the next fifteen years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates, projected inflation rates, and the estimated timing and amounts of settling our obligations, which are based on internal models and external quotes. The following is a summary of our asset retirement liabilities and the significant assumptions we used at December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions, except for rates) | |
| Current asset retirement liability | $ 28 | $ 26 |
| Non-current asset retirement liability[1] | $244 | $192 |
| Discount rates | 6-8% | 8-10% |
| Inflation rates | 2.5% | 2.5% |

[1] We estimate that approximately 61 percent of our non-current asset retirement liability as of December 31, 2004 will be settled in the next five years.

Our asset retirement liabilities are recorded at their estimated fair value utilizing the assumptions above, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $9 million, net of income taxes, related to our adoption of SFAS No. 143.

The net asset retirement liability as of December 31, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the year ended December 31, were as follows (in millions):

| | 2004 | 2003 |
|---|---|---|
| Net asset retirement liability at January 1 | $218 | $209 |
| Liabilities settled | (34) | (39) |
| Accretion expense | 24 | 22 |
| Liabilities incurred | 34 | 13 |
| Changes in estimate | 30 | 13 |
| Net asset retirement liability at December 31 | $272 | $218 |

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our aggregate current and non-current retirement liabilities on that date would have been approximately $187 million and our income from continuing operations and net income for the year ended December 31, 2002 would have been lower by $15 million. Basic and diluted earnings per share for the year ended December 31, 2002 would not have been materially affected.

*Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. On July 1, 2003, we adopted the provisions of SFAS No. 150, and reclassified $625 million of our Capital Trust I and Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement. These dividends were $40 million in both 2004 and 2003. These dividends were recorded in interest and debt expense in 2004, and $20 million of our 2003 dividends were recorded in interest expense and $20 million were recorded as distributions on preferred interests in our income statement in 2003.

*New Accounting Pronouncements Issued But Not Yet Adopted*

As of December 31, 2004, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

*Accounting for Stock-Based Compensation.* In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95.* This standard requires that companies measure and record the fair value of their stock based compensation awards at fair value on the date they are granted to employees. This fair value is determined based on a variety of assumptions, including volatility rates, forfeiture rates and the option pricing model used (e.g. binomial or Black Scholes). These assumptions could significantly differ from those we currently utilize in determining the proforma compensation expense included in our disclosures required under SFAS No. 123. This standard will also impact the manner in which we recognize the income tax impacts of our stock compensation programs in our financial statements. This standard is effective for interim periods beginning after June 15, 2005, at which time companies can select whether they will apply the standard retroactively by restating their historical financial statements or prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We will adopt this pronouncement in the third quarter of 2005 and are currently evaluating its impact on our consolidated financial statements.

*Accounting for Deferred Taxes on Foreign Earnings.* In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

## 2. Acquisitions and Consolidations

*Acquisitions*

During 2003, we acquired the remaining third party interests in our Chaparral and Gemstone investments and began consolidating them in the first and second quarters of 2003, respectively. We historically accounted for these investments using the equity method of accounting. Each of these acquisitions is discussed below.

*Chaparral.* We entered into our Chaparral investment in 1999 to expand our domestic power generation business. Chaparral owned or had interests in 34 power plants in the United States that have a total generating capacity of 3,470 megawatts (based on Chaparral's interest in the plants). These plants were primarily concentrated in the Northeastern and Western United States. Chaparral also owned several companies that own long-term derivative power agreements.

At December 31, 2002, we owned 20 percent of Chaparral and the remaining 80 percent was owned by Limestone Electron Trust (Limestone). During 2003, we paid $1,175 million to acquire Limestone's 80 percent interest in Chaparral. Limestone used $1 billion of these proceeds to retire notes that were previously guaranteed by us. We have reflected Chaparral's results of operations in our income statement as though we acquired it on January 1, 2003. Had we acquired Chaparral effective January 1, 2002, the net increases (decreases) to our income statement for the year ended December 31, 2002, would have been as follows (in millions):

| | (Unaudited) |
|---|---|
| Revenues | $ 223 |
| Operating income | (119) |
| Net income | 19 |
| Basic and diluted earnings per share | $ 0.03 |

During the first quarter of 2003, we recorded an impairment of our investment in Chaparral of $207 million before income taxes as further discussed in Note 22.

The following table presents our allocation of the purchase price of Chaparral to its assets and liabilities prior to its consolidation and prior to the elimination of intercompany transactions. This allocation reflects the allocation of (i) our purchase price of $1,175 million; (ii) the carrying value of our initial investment of $252 million; and (iii) the impairment of $207 million (in millions):

| | |
|---|---|
| *Total assets* | |
| Current assets | $ 312 |
| Assets from price risk management activities, current | 190 |
| Investments in unconsolidated affiliates | 1,366 |
| Property, plant and equipment, net | 519 |
| Assets from price risk management activities, non-current | 1,089 |
| Goodwill | 22 |
| Other assets | 467 |
| Total assets | 3,965 |
| *Total liabilities* | |
| Current liabilities | 908 |
| Liabilities from price risk management activities, current | 19 |
| Long-term debt, less current maturities[(1)] | 1,433 |
| Liabilities from price risk management activities, non-current | 34 |
| Other liabilities | 351 |
| Total liabilities | 2,745 |
| Net assets | $1,220 |

(1) This debt is recourse only to the project, contract or plant to which it relates.

Our allocation of the purchase price was based on valuations performed by an independent third party consultant, which were finalized in December 2003 with no significant changes to the initial purchase price allocation. These valuations were derived using discounted cash flow analyses and other valuation methods. These valuations indicated that the fair value of the net assets purchased from Chaparral was less than the purchase price we paid for Chaparral by $22 million, which we recorded as goodwill in our financial statements. See Note 1 for a discussion of the subsequent impairment of this goodwill.

*Gemstone.* We entered into the Gemstone investment in 2001 to finance five major power plants in Brazil. Gemstone had investments in three power projects (Macae, Porto Velho and Araucaria) and also owned a preferred interest in two of our consolidated power projects, Rio Negro and Manaus. In 2003, we acquired the third-party investor's (Rabobank) interest in Gemstone for approximately $50 million. Gemstone's results of operations have been included in our consolidated financial statements since April 1, 2003. Had we acquired Gemstone effective January 1, 2003, our net income and basic and diluted earnings per share for the year ended December 31, 2003 would not have been affected, but our revenues and operating income would have been higher by $58 million and $41 million (amounts unaudited). Had the acquisition been effective January 1, 2002, our 2002 net income and our basic and diluted earnings per share would not have been affected, but our revenues and operating income would have been higher by $187 million and $134 million (amounts unaudited).

Our allocation of the purchase price to the assets acquired and liabilities assumed upon our consolidation of Gemstone was as follows (in millions):

| | |
|---|---|
| *Fair value of assets acquired* | |
| Note and interest receivable | $ 122 |
| Investments in unconsolidated affiliates | 892 |
| Other assets | 3 |
| Total assets | 1,017 |
| *Fair value of liabilities assumed* | |
| Note and interest payable | 967 |
| Total liabilities | 967 |
| Net assets acquired | $ 50 |

Our allocation of the purchase price was based on valuations performed by an independent third party consultant, which were finalized in December 2003 with no significant changes to the initial purchase price allocation. These valuations were derived using discounted cash flow analyses and other valuation methods.

Prior to our acquisitions of Chaparral and Gemstone, we had other balances, including loans and notes with Chaparral and Gemstone, which were eliminated upon consolidation. As a result, the overall impact on our consolidated balance sheet from acquiring these investments was different than the individual assets and liabilities acquired. The overall impact of these acquisitions on our consolidated balance sheet was an increase in our consolidated assets of $2.1 billion, an increase in our consolidated liabilities of approximately $2.4 billion (including an increase in our consolidated debt of approximately $2.2 billion) and a reduction of our preferred interests in consolidated subsidiaries of approximately $0.3 billion.

*Consolidations*

*Variable Interest Entities.* In 2003, the FASB issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses or returns, including fees paid by the entity.

On January 1, 2004, we adopted this standard. Upon adoption, we consolidated Blue Lake Gas Storage Company and several other minor entities and deconsolidated a previously consolidated entity, EMA Power Kft. The overall impact of these actions is described in the following table:

| | Increase/(Decrease) (In millions) |
|---|---|
| Restricted cash | $ 34 |
| Accounts and notes receivable from affiliates | (54) |
| Investments in unconsolidated affiliates | (5) |
| Property, plant, and equipment, net | 37 |
| Other current and non-current assets | (15) |
| Long-term financing obligations | 15 |
| Other current and non-current liabilities | (4) |
| Minority interest of consolidated subsidiaries | (14) |

Blue Lake Gas Storage owns and operates a 47 Bcf gas storage facility in Michigan. One of our subsidiaries operates the natural gas storage facility and we inject and withdraw all natural gas stored in the facility. We own a 75 percent equity interest in Blue Lake. This entity has $8 million of third party debt as of

December 31, 2004 that is non-recourse to us. We consolidated Blue Lake because we are allocated a majority of Blue Lake's losses and returns through our equity interest in Blue Lake.

EMA Power Kft owns and operates a 69 gross MW dual-fuel-fired power facility located in Hungary. We own a 50 percent equity interest in EMA. Our equity partner has a 50 percent interest in EMA, supplies all of the fuel consumed and purchases all of the power generated by the facility. Our exposure to this entity is limited to our equity interest in EMA, which was approximately $43 million as of December 31, 2004. We deconsolidated EMA because our equity partner is allocated a majority of EMA's losses and returns through its equity interest and its fuel supply and power purchase agreements with EMA.

We have significant interests in a number of other variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of December 31, 2004, these entities consisted primarily of 20 equity and cost investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 7,300 gross MW. We operate many of these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. The long-term debt issued by these entities is recourse only to the power project. As a result, our exposure to these entities is limited to our equity investments in and advances to the entities ($1.1 billion as of December 31, 2004) and our guarantees and other agreements associated with these entities (a maximum of $80 million as of December 31, 2004).

During our adoption of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity's two 274 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $27 million to $32 million per year related to its power plants. The following is a summary of the financial statement impacts of our transactions with this entity for the year ended December 31, 2004 and 2003, and as of December 31, 2004 and December 31, 2003:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Operating revenues | $(36) | $ 75 |
| Current liabilities from price risk management activities | (20) | (28) |
| Non-current liabilities from price risk management activities | (29) | (6) |

As of December 31, 2004, our financial statements included two consolidated entities that own a 238 MW power facility and a 158 MW power facility in Manaus, Brazil. In January 2005, we entered into agreements with Manaus Energia, under which Manaus Energia will supply substantially all of the fuel consumed and will purchase all of the power generated by the projects through January 2008, at which time Manaus Energia will assume ownership of the plants. We deconsolidated these two entities in January 2005 because Manaus Energia will assume ownership of the plants and since they will absorb a majority of the potential losses of the entities under the new agreements. The impact of this deconsolidation will be an increase in investments in unconsolidated affiliates of $103 million, a decrease in property, plant and equipment of $74 million and a net decrease in other assets and liabilities of $29 million in the first quarter of 2005.

*Lakeside.* In 2003, we amended an operating lease agreement at our Lakeside Technology Center to add a guarantee benefiting the party who had invested in the lessor and to allow the third party and certain lenders to share in the collateral package that was provided to the banks under our previous $3 billion revolving credit facility. This guarantee reduced the investor's risk of loss of its investment, resulting in our controlling the lessor. As a result, we consolidated the lessor. The consolidation of Lakeside Technology Center resulted in an increase in our property, plant and equipment of approximately $275 million and an increase in our long-term debt of approximately $275 million. In 2004, we repaid the $275 million that was scheduled to mature in 2006. Additionally, upon its consolidation, we recorded an asset impairment charge of approximately $127 million representing the difference between the facility's estimated fair value and the residual value guarantee under the lease. Prior to its consolidation, this difference was being periodically expensed as part of operating lease expense over the term of the lease.

*Clydesdale.* In 2003, we modified our Clydesdale financing arrangement to convert a third-party investor's (Mustang Investors, L.L.C.) preferred ownership interest in one of our consolidated subsidiaries into a term loan that matures in equal quarterly installments through 2005. We also acquired a $10 million preferred interest in Mustang and guaranteed all of Mustang's equity holder's obligations. As a result, we consolidated Mustang which increased our long-term debt by $743 million and decreased our preferred interests of consolidated subsidiaries by $753 million. The $10 million preferred interest we acquired in Mustang was eliminated upon its consolidation. In December 2003, we repaid the remaining Clydesdale debt obligation (see Notes 15 and 16).

## 3. Divestitures

*Sales of Assets and Investments*

During 2004, 2003 and 2002, we completed and announced the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| *Regulated* | | | |
| Pipelines | $ 59 | $ 145 | $ 303 |
| *Non-regulated* | | | |
| Production | 24 | 673 | 1,248 |
| Power | 884 | 768 | 90 |
| Field Services | 1,029 | 753 | 1,513 |
| *Other* | | | |
| Corporate | 16 | 149 | — |
| Total continuing[(1)] | 2,012 | 2,488 | 3,154 |
| Discontinued | 1,295 | 808 | 177 |
| Total | $3,307 | $3,296 | $3,331 |

(1) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $85 million, $30 million, and $25 million for the years ended December 31, 2004, 2003 and 2002. Proceeds also exclude any non-cash consideration received in these sales, such as the receipt of $350 million of Series C units in GulfTerra from the sale of assets in our Field Services segment in 2002.

The following table summarizes the significant assets sold:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Pipelines | • Australian pipelines<br>• Interest in gathering systems | • 2.1% interest in Alliance pipeline<br>• Equity interest in Portland Natural Gas Transmission System<br>• Horsham pipeline in Australia | • Natural gas and oil properties located in TX, KS, and OK<br>• 12.3% equity interest in Alliance pipeline<br>• Typhoon natural gas pipeline |
| Production | • Brazilian exploration and production acreage | • Natural gas and oil properties in NM, TX, LA, OK and the Gulf of Mexico | • Natural gas and oil properties located in TX, CO and Utah |
| Power | • Utility Contract Funding<br>• 31 domestic power plants and several turbines | • Interest in CE Generation L.L.C.<br>• Mt. Carmel power plant<br>• CAPSA/CAPEX investments<br>• East Coast Power | • 40% equity interest in Samalayuca Power II power project in Mexico |
| Field Services | • Remaining general partnership interest, common units and Series C units in GulfTerra<br>• South TX processing plants<br>• Dauphin Island and Mobile Bay investments | • Gathering systems located in WY<br>• Midstream assets in the north LA and Mid-Continent regions<br>• Common and Series B preference units in GulfTerra<br>• 50% of GulfTerra General Partnership | • TX & NM midstream assets<br>• Dragon Trail gas processing plant<br>• San Juan basin gathering, treating and processing assets<br>• Gathering facilities in Utah |
| Corporate | • Aircraft | • Aircraft<br>• Enerplus Global Energy Management Company and its financial operations<br>• EnCap funds management business and its investments | • None |
| Discontinued | • Natural gas and oil production properties in Canada and other international production assets<br>• Aruba and Eagle Point refineries and other petroleum assets | • Corpus Christi refinery<br>• Florida petroleum terminals<br>• Louisiana lease crude<br>• Coal reserves<br>• Canadian natural gas and oil properties<br>• Asphalt facilities | • Coal reserves and properties and petroleum assets<br>• Natural gas and oil properties located in Western Canada |

See Note 5 for a discussion of gains, losses and asset impairments related to the sales above.

During 2005, we have either completed or announced the following sales:

- Remaining 9.9% membership interest in the general partner of Enterprise and approximately 13.5 million units in Enterprise for $425 million;
- Interests in Cedar Brakes I and II for $94 million;
- Interest in a paraxylene plant for $74 million;
- Interest in a natural gas gathering system and processing facility for $75 million;
- Pipeline facilities for $31 million;
- Interest in an Indian power plant for $20 million;
- MTBE processing facility for $5 million;
- Eagle Point power facility for $3 million; and
- Interest in the Rensselaer power facility and its obligations.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. These assets consist of certain of our domestic power plants and natural gas gathering and processing assets in our Field Services segment. As of December 31, 2004, we had assets held for sale of $75 million related to our Indian Springs natural gas gathering and processing facility, which was sold in January 2005, and four domestic power assets, which were impaired in previous years and which we expect to sell within the next twelve months. The following table details the items which are reflected as current assets and liabilities held for sale in our balance sheet as of December 31, 2003 (in millions).

| | |
|---|---|
| *Assets Held for Sale* | |
| Current assets | $ 46 |
| Investments in unconsolidated affiliates | 480 |
| Property, plant and equipment, net | 477 |
| Other assets | 136 |
| Total assets | $1,139 |
| Current liabilities | $ 54 |
| Long-term debt, less current maturities | 169 |
| Other liabilities | 13 |
| Total liabilities | $ 236 |

*Discontinued Operations*

*International Natural Gas and Oil Production Operations.* During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. During 2004, we recognized approximately $99 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties by mid-2005.

*Petroleum Markets.* During 2003, the sales of our petroleum markets businesses and operations were approved. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax impairment charges during 2003 of approximately $1.5 billion related to these assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately $59 million in 2003 from the sale of our Corpus Christi refinery, our asphalt assets and our Florida terminalling and marine assets.

In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million and used a portion of the proceeds to repay $370 million of debt associated with the Aruba refinery. We recorded realized losses of approximately $32 million in 2004, primarily from the sale of our Aruba and Eagle Point refineries. In addition, in 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing operations in our financial statements based on our decision to retain these operations. Our financial statements for all periods presented reflect this change.

*Coal Mining.* In 2002, our Board of Directors authorized the sale of our coal mining operations and we recorded an impairment of $185 million. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. The sale of these operations was completed in 2003 for $92 million in cash and $24 million in notes receivable, which were settled in the second quarter of 2004. We did not record a significant gain or loss on these sales.

The petroleum markets, coal mining and our other international natural gas and oil production operations discussed above, are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of December 31, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

| | Petroleum Markets | International Natural Gas and Oil Production Operations | Coal Mining | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| *Operating Results Data* | | | | |
| **Year Ended December 31, 2004** | | | | |
| Revenues | $ 787 | $ 31 | $ — | $ 818 |
| Costs and expenses | (839) | (53) | — | (892) |
| Loss on long-lived assets | (36) | (99) | — | (135) |
| Other income | 23 | — | — | 23 |
| Interest and debt expense | (3) | 1 | — | (2) |
| Loss before income taxes | (68) | (120) | — | (188) |
| Income taxes | 2 | (44) | — | (42) |
| Loss from discontinued operations, net of income taxes | $ (70) | $ (76) | $ — | $ (146) |

| | Petroleum Markets | International Natural Gas and Oil Production Operations | Coal Mining | Total |
|---|---|---|---|---|
| | | (In millions) | | |
| **Year Ended December 31, 2003 (Restated)** | | | | |
| Revenues | $ 5,652 | $ 88 | $ 27 | $ 5,767 |
| Costs and expenses | (5,793) | (129) | (13) | (5,935) |
| Loss on long-lived assets | (1,404) | (89) | (9) | (1,502) |
| Other income | (10) | — | 1 | (9) |
| Interest and debt expense | (11) | 4 | — | (7) |
| Gain (loss) before income taxes | (1,566) | (126) | 6 | (1,686) |
| Income taxes | (262) | (115) | 5 | (372) |
| Gain (loss) from discontinued operations, net of income taxes | $(1,304) | $ (11) | $ 1 | $(1,314) |
| **Year Ended December 31, 2002** | | | | |
| Revenues | $ 4,788 | $ 71 | $ 309 | $ 5,168 |
| Costs and expenses | (4,916) | (172) | (327) | (5,415) |
| Loss on long-lived assets | (97) | (4) | (184) | (285) |
| Other income | 20 | — | 5 | 25 |
| Interest and debt expense | (12) | 4 | — | (8) |
| Loss before income taxes | (217) | (101) | (197) | (515) |
| Income taxes | 16 | (33) | (73) | (90) |
| Loss from discontinued operations, net of income taxes | $ (233) | $ (68) | $(124) | $ (425) |

| | Petroleum Markets | International Natural Gas and Oil Production Operations | Total |
|---|---|---|---|
| | | (In millions) | |
| *Financial Position Data* | | | |
| **December 31, 2004** | | | |
| Assets of discontinued operations | | | |
| Accounts and notes receivable | $ 39 | $ 2 | $ 41 |
| Inventory | 8 | — | 8 |
| Other current assets | 3 | 1 | 4 |
| Property, plant and equipment, net | 14 | 6 | 20 |
| Other non-current assets | 33 | — | 33 |
| Total assets | $ 97 | $ 9 | $ 106 |
| Liabilities of discontinued operations | | | |
| Accounts payable | $ 5 | $ 1 | $ 6 |
| Other current liabilities | 3 | — | 3 |
| Other non-current liabilities | 3 | — | 3 |
| Total liabilities | $ 11 | $ 1 | $ 12 |

| | Petroleum Markets | International Natural Gas and Oil Production Operations | Total |
|---|---|---|---|
| | | (In millions) | |
| **December 31, 2003** | | | |
| Assets of discontinued operations | | | |
| Accounts and notes receivable | $ 259 | $ 22 | $ 281 |
| Inventory | 385 | 3 | 388 |
| Other current assets | 131 | 8 | 139 |
| Property, plant and equipment, net | 521 | 399 | 920 |
| Other non-current assets | 70 | 6 | 76 |
| Total assets | $1,366 | $438 | $1,804 |
| Liabilities of discontinued operations | | | |
| Accounts payable | $ 172 | $ 39 | $ 211 |
| Other current liabilities | 86 | — | 86 |
| Long-term debt | 374 | — | 374 |
| Other non-current liabilities | 26 | 3 | 29 |
| Total liabilities | $ 658 | $ 42 | $ 700 |

## 4. Restructuring Costs

As a result of actions taken in 2002, 2003, and 2004, we incurred certain organizational restructuring costs included in operation and maintenance expense. On January 1, 2003, we adopted the provisions of SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, and recognized restructuring costs applying the provisions of that standard. Prior to this date, we had recognized restructuring costs according to the provisions of EITF Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity*. By segment, our restructuring costs for the years ended December 31, were as follows:

| | Pipelines | Production | Marketing and Trading | Power | Field Services | Corporate and Other | Total |
|---|---|---|---|---|---|---|---|
| | | | (In millions) | | | | |
| 2004 | | | | | | | |
| Employee severance, retention and transition costs | $ 5 | $14 | $ 2 | $ 5 | $ 1 | $11 | $ 38 |
| Office relocation and consolidation | — | — | — | — | — | 80 | 80 |
| | $ 5 | $14 | $ 2 | $ 5 | $ 1 | $91 | $118 |
| 2003 | | | | | | | |
| Employee severance, retention and transition costs | $ 2 | $ 6 | $12 | $ 5 | $ 4 | $47 | $ 76 |
| Contract termination and other costs | — | — | 4 | — | — | 44 | 48 |
| | $ 2 | $ 6 | $16 | $ 5 | $ 4 | $91 | $124 |
| 2002 | | | | | | | |
| Employee severance, retention and transition costs | $ 1 | $— | $10 | $14 | $ 1 | $11 | $ 37 |
| Transaction costs | — | — | — | — | — | 40 | 40 |
| | $ 1 | $— | $10 | $14 | $ 1 | $51 | $ 77 |

During the period from 2002 to 2004, we incurred substantial restructuring charges as part of our ongoing liquidity enhancement and cost reduction efforts. Below is a summary of these costs:

*Employee severance, retention, and transition costs.* During 2002, 2003, and 2004, we incurred employee severance costs, which included severance payments and costs for pension benefits settled under existing benefit plans. During this period, we eliminated approximately 1,900 full-time positions from our continuing business and approximately 1,200 positions related to businesses we discontinued in 2004, 900 full-time positions from our continuing businesses and approximately 1,800 positions related to businesses we discontinued in 2003, and 900 full-time positions through terminations in 2002. As of December 31, 2004, all but $15 million of the total employee severance, retention and transition costs had been paid.

*Office relocation and consolidation.* In May 2004, we announced that we would begin consolidating our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004, we had established an accrual totaling $80 million to record the discounted liability, net of estimated sub-lease rentals, for our obligations under our existing lease terms. These leases expire at various times through 2014. Of the approximate 888,000 square feet of office space that we lease, we have vacated approximately 741,000 square feet as of December 31, 2004. In addition, we have subleased approximately 238,000 square feet of this space in the third and fourth quarters of 2004. Actual moving expenses related to the relocation were insignificant and were expensed in the period that they were incurred. All amounts related to the relocation are expensed in our corporate operations.

*Other.* In 2003, our contract termination and other costs included charges of approximately $44 million related to amounts paid for canceling or restructuring our obligations to transport LNG from supply areas to domestic and international market centers. In 2002, we incurred and paid fees of $40 million to eliminate stock price and credit rating triggers related to our Chaparral and Gemstone investments.

## 5. Loss on Long-Lived Assets

Loss on long-lived assets from continuing operations consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets including goodwill and other intangibles. During each of the three years ended December 31, our losses on long-lived assets were as follows:

| | 2004 | 2003 | 2002 (Restated) |
|---|---|---|---|
| | | (In millions) | |
| Net realized (gain) loss | $ (16) | $ 69 | $(259) |
| Asset impairments | | | |
| Power | | | |
| Domestic assets and restructured power contract entities | 397 | 147 | — |
| International assets | 197 | — | — |
| Turbines | 1 | 33 | 162 |
| Field Services | | | |
| South Texas processing assets | — | 167 | — |
| North Louisiana gathering facility | — | — | 66 |
| Indian Springs processing assets | 13 | — | — |
| Goodwill impairment | 480 | — | — |
| Other | 11 | 4 | — |
| Production | | | |
| Other | 8 | 10 | — |
| Corporate | | | |
| Telecommunications assets | — | 396 | 168 |
| Other | 1 | 34 | 44 |
| Total asset impairments | 1,108 | 791 | 440 |
| Loss on long-lived assets | 1,092 | 860 | 181 |
| (Gain) loss on investments in unconsolidated affiliates[(1)] | (129) | 176 | 612 |
| (Gain) loss on assets and investments | $ 963 | $1,036 | $ 793 |

(1) See Note 22 for a further description of these gains and losses.

*Net Realized (Gain) Loss*

Our 2004 net realized gain was primarily related to $10 million of gains in our Power segment and $8 million of gains in our Corporate operations from the disposition of assets offset by the $11 million loss on the sale of our South Texas assets in our Field Services segment.

Our 2003 net realized loss was primarily related to a $74 million loss on an agreement to reimburse GulfTerra for a portion of future pipeline integrity costs on previously sold assets. We reduced this accrual by $9 million in 2004 (see Note 22). We also recorded a $67 million gain on the release of our purchase obligation for the Chaco facility and a $14 million gain on the sale of our north Louisiana and Mid-Continent midstream assets in our Field Services segment as well as a $75 million loss on and the termination of our Energy Bridge contracts in the Corporate and other segment and a $10 million loss on the sale of Mohawk River Funding I in our Power segment.

Our 2002 net realized gain was primarily related to $245 million of net gains on the sales of our San Juan gathering assets, our Natural Buttes and Ouray gathering systems, our Dragon Trail gas processing plant and our Texas and New Mexico assets in our Field Services segment. See Note 3 for a further discussion of these divestitures.

*Asset Impairments*

Our impairment charges for the years ended December 31, 2004, 2003 and 2002, were recorded primarily in connection with our intent to dispose of, or reduce our involvement in, a number of assets.

Our 2004 Power segment charges include a $227 million impairment on the sale of our domestic equity interests in Cedar Brakes I and II, which closed in the first quarter of 2005, a $167 million impairment of our Manaus and Rio Negro power facilities in Brazil as a result of renegotiating and extending their power purchase agreements, and a $30 million impairment on our consolidated Asian assets in connection with our decision to sell these assets. In addition, in 2004, we impaired UCF prior to its sale by $98 million and recorded impairments of $73 million related to the sales of various other power assets and turbines. Our 2003 and 2002 Power segment impairment charges were primarily a result of our planned sale of domestic power assets (including our turbines classified in long-term assets).

Our Field Services charges include a $480 million impairment of the goodwill associated with the Enterprise sale in 2004 on which we realized an offsetting pretax gain of $507 million recorded in earnings from unconsolidated affiliates, a $24 million impairment on the sales or abandonment of assets in 2004, an impairment of our south Texas processing facilities of $167 million in 2003 based on our planned sale of these facilities to Enterprise (see Note 22), and a $66 million impairment that resulted from our decision to sell our north Louisiana gathering facilities in 2002.

Our corporate telecommunications charge includes an impairment of our investment in the wholesale metropolitan transport services, primarily in Texas, of $269 million in 2003 (including a writedown of goodwill of $163 million) and a 2003 impairment of our Lakeside Technology Center facility of $127 million based on an estimate of what the asset could be sold for in the current market. In 2002, we incurred $168 million of corporate telecommunication charges related to the impairment of our long-haul fiber network and right-of-way assets.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 3 and 22. For additional discussion on goodwill and other intangibles, see Note 1.

## 6. Other Income and Other Expenses

The following are the components of other income and other expenses from continuing operations for each of the three years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| Other Income | | | |
| Interest income | $ 93 | $ 83 | $ 84 |
| Allowance for funds used during construction | 23 | 19 | 7 |
| Development, management and administrative services fees on power projects from affiliates | 21 | 18 | 21 |
| Re-application of SFAS No. 71 (CIG and WIC) | — | 18 | — |
| Net foreign currency gain | 9 | 12 | — |
| Favorable resolution of non-operating contingent obligations | — | 9 | 38 |
| Gain on early extinguishment of debt | — | — | 21 |
| Other | 43 | 44 | 26 |
| Total | $189 | $203 | $197 |

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| Other Expenses | | | |
| Net foreign currency losses[1] | $ 26 | $112 | $ 91 |
| Loss on early extinguishment of debt | 12 | 37 | — |
| Loss on exchange of equity security units | — | 12 | — |
| Impairment of cost basis investment[2] | — | 5 | 56 |
| Minority interest in consolidated subsidiaries | 41 | 1 | 58 |
| Other | 20 | 35 | 34 |
| Total | $ 99 | $202 | $239 |

(1) Amounts in 2004, 2003 and 2002 were primarily related to losses on our Euro-denominated debt.
(2) We impaired our investment in our Costañera power plant in 2002.

## 7. Income Taxes

Our pretax loss from continuing operations is composed of the following for each of the three years ended December 31:

| | 2004 | 2003 | 2002 (Restated) |
|---|---|---|---|
| | | (In millions) | |
| U.S. | $(698) | $(1,330) | $(2,282) |
| Foreign | (79) | 256 | 399 |
| | $(777) | $(1,074) | $(1,883) |

The following table reflects the components of income tax expense (benefit) included in loss from continuing operations for each of the three years ended December 31:

| | 2004 | 2003 (Restated) | 2002 (Restated) |
|---|---|---|---|
| | | (In millions) | |
| Current | | | |
| Federal | $ (15) | $ 36 | $ (15) |
| State | 39 | 58 | 27 |
| Foreign | 39 | 41 | 32 |
| | 63 | 135 | 44 |
| Deferred | | | |
| Federal | (63) | (556) | (679) |
| State | (5) | (55) | (11) |
| Foreign | 30 | 7 | 5 |
| | (38) | (604) | (685) |
| Total income taxes | $ 25 | $(469) | $(641) |

Our income taxes, included in loss from continuing operations, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

| | 2004 | 2003 (Restated) | 2002 (Restated) |
|---|---|---|---|
| | (In millions, except rates) | | |
| Income taxes at the statutory federal rate of 35% | $(272) | $(376) | $(659) |
| Increase (decrease) | | | |
| Abandonments and sales of foreign investments | (4) | (43) | — |
| Valuation allowances | 18 | (57) | 44 |
| Foreign income taxed at different rates | 155 | (21) | 6 |
| Earnings from unconsolidated affiliates where we anticipate receiving dividends | (18) | (13) | (18) |
| Non-deductible dividends on preferred stock of subsidiaries | 9 | 10 | 10 |
| State income taxes, net of federal income tax effect | 5 | 5 | 2 |
| Non-conventional fuel tax credits | — | — | (11) |
| Non-deductible goodwill impairments | 139 | 29 | — |
| Other | (7) | (3) | (15) |
| Income taxes | $ 25 | $(469) | $(641) |
| Effective tax rate | (3)% | 44% | 34% |

The following are the components of our net deferred tax liability related to continuing operations as of December 31:

| | 2004 | 2003 (Restated) |
|---|---|---|
| | (In millions) | |
| Deferred tax liabilities | | |
| Property, plant and equipment | $2,590 | $2,147 |
| Investments in unconsolidated affiliates | 410 | 757 |
| Employee benefits and deferred compensation | 93 | 126 |
| Price risk management activities | 71 | — |
| Regulatory and other assets | 163 | 193 |
| Total deferred tax liability | 3,327 | 3,223 |
| Deferred tax assets | | |
| Net operating loss and tax credit carryovers | | |
| U.S. federal | 1,196 | 814 |
| State | 174 | 146 |
| Foreign | 35 | 18 |
| Western Energy Settlement | 144 | 400 |
| Environmental liability | 174 | 206 |
| Price risk management activities | — | 136 |
| Debt | 79 | 105 |
| Inventory | 85 | 91 |
| Deferred federal tax on deferred state income tax liability | 59 | 75 |
| Allowance for doubtful accounts | 99 | 75 |
| Lease liabilities | 53 | — |
| Other | 387 | 276 |
| Valuation allowance | (51) | (9) |
| Total deferred tax asset | 2,434 | 2,333 |
| Net deferred tax liability | $ 893 | $ 890 |

In 2004, Congress proposed but failed to enact legislation which would disallow deductions for certain settlements made to or on behalf of governmental entities. It is possible Congress will reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy

Settlement and could result in a write-off of some or all of the associated tax benefits. In such event, our tax expense would increase. Our total tax benefits related to the Western Energy Settlement were approximately $400 million as of December 31, 2004.

Historically, we have not recorded U.S. deferred tax liabilities on book versus tax basis differences in our Asian power investments because it was our historical intent to indefinitely reinvest the earnings from these projects outside the U.S. In 2004, our intent on these assets changed such that we now intend to use the proceeds from the sale within the U.S. As a result, we recorded deferred tax liabilities which, as of December 31, 2004 were $39 million, representing those instances where the book basis in our investments in the Asian power projects exceeded the tax basis. At this time, however, due to uncertainties as to the manner, timing and approval of the sales, we have not recorded deferred tax assets for those instances where the tax basis of our investments exceeded the book basis, except in instances where we believe the realization of the asset is assured. As of December 31, 2004, total deferred tax assets recorded on our Asian investments was $6 million.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. At December 31, 2004, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $551 million. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income other than $4 million included in the deferred tax liability we recorded related to our investment in our Asian power projects.

The tax effects associated with our employees' non-qualified dispositions of employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends are included in additional paid-in-capital in our balance sheets.

As of December 31, 2004, we have U.S. federal alternative minimum tax credits of $283 million and state alternative minimum assessment tax credits of $1 million that carryover indefinitely, $1 million of general business credit carryovers for which the carryover periods end at various times in the years 2012 through 2021, capital loss carryovers of $87 million and charitable contributions carryovers of $2 million for which the carryover periods end in 2008. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2004:

| | Carryover Period | | | | |
|---|---|---|---|---|---|
| | 2005 | 2006-2010 | 2011-2015 | 2016-2024 | Total |
| | | | (In millions) | | |
| U.S. federal net operating loss | $— | $ 7 | $ — | $3,118 | $3,125 |
| State net operating loss | 8 | 849 | 412 | 987 | 2,256 |

We also had $103 million of foreign net operating loss carryovers that carryover indefinitely. Usage of our U.S. federal 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.

We record a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2004, we maintained a valuation allowance of $37 million related to state net operating loss carryovers, $7 million related to our estimated ability to realize state tax benefits from the deduction of the charge we took related to the Western Energy Settlement, $5 million related to foreign deferred tax assets for book impairments and ceiling test charges, $1 million related to a general business credit carryover and $1 million related to other carryovers. As of December 31, 2003, we maintained a valuation allowance of $5 million related to state tax benefits of the Western Energy Settlement, $1 million related to state net operating loss carryovers, $1 million related to foreign deferred tax assets for ceiling test charges and $1 million related to a general business credit carryover and $1 million related to other carryovers. The change in our valuation allowances from December 31, 2003 to December 31, 2004 is primarily related to an additional valuation allowance for State of New Jersey legislation that limited use of net operating loss carryovers, an increase in valuation allowances on foreign impairments of assets and an increase in the state valuation allowance related to the Western Energy Settlement.

We are currently under audit by the IRS and other taxing authorities, and our audits are in various stages of completion. The tax years for 1995-2000 are pending with the IRS Appeals Office related to The Coastal Corporation, with which we merged in 2001. We anticipate that the Appeals proceedings for 1995-1997 will be finalized within 12 months, while the other years will take longer to complete. The IRS has completed its examination of El Paso's tax years through 2000. The 2001-2002 tax years are currently under examination, which we anticipate will be completed within 12 months. There may be additional proceedings in the IRS Appeals Office with respect to this examination. We maintain a reserve for tax contingencies that management believes is adequate, and as audits are finalized we will make appropriate adjustments to those estimates.

## 8. Earnings Per Share

We incurred losses from continuing operations during the three years ended December 31, 2004. Accordingly, we excluded a number of securities for the years ended December 2004, 2003, and 2002, from the determination of diluted earnings per share due to their antidilutive effect on loss per common share. These included stock options, restricted stock, trust preferred securities, equity security units, and convertible debentures. Additionally, in 2003, we excluded shares related to our remaining stock obligation under the Western Energy Settlement (see Note 17 for further information). For a further discussion of these instruments, see Notes 15 and 20.

## 9. Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31, 2004 and 2003.

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In millions) | | | |
| Long-term financing obligations, including current maturities | $19,189 | $19,829 | $21,724 | $21,166 |
| Commodity-based price risk management derivatives | 68 | 68 | 1,406 | 1,406 |
| Interest rate and foreign currency hedging derivatives | 239 | 239 | 123 | 123 |
| Investments | 6 | 6 | 12 | 12 |

As of December 31, 2004 and 2003, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represented 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 interest rate. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. See Note 10 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

## 10. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2004 and 2003. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production as well as instruments to hedge our interest rate and currency risks on long-term debt. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities.

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Net assets (liabilities) | | |
| Derivatives designated as hedges[(1)] | $(536) | $ (31) |
| Derivatives from power contract restructuring activities[(2)] | 665 | 1,925 |
| Other commodity-based derivative contracts[(1)] | (61) | (488) |
| Total commodity-based derivatives | 68 | 1,406 |
| Interest rate and foreign currency hedging derivatives | 239 | 123 |
| Net assets from price risk management activities[(3)] | $ 307 | $1,529 |

(1) In December 2004, we designated other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004.

(2) Includes derivative contracts with a fair value of $596 million as of December 31, 2004 that we sold in connection with the sale of Cedar Brakes I and II in the first quarter of 2005, and $942 million as of December 31, 2003 that we sold in connection with the sales of UCF and Mohawk River Funding IV in 2004.

(3) Included in both current and non-current assets and liabilities from price risk management activities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. Due to major industry participants exiting or reducing their trading activities in 2002 and 2003, the availability of reliable commodity pricing data from market-based sources that we used in estimating the fair value of our derivatives was significantly limited for certain locations and for longer time periods. Consequently, we now use an independent pricing source for a substantial amount of our forward pricing data beyond the current two-year period. For forward pricing data within two years, we use commodity prices from market-based sources such as the New York Mercantile Exchange. For periods beyond two years, we use a combination of commodity prices from market-based sources and other forecasted settlement prices from an independent pricing source to develop price curves, which we then use to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discount these estimated settlement values using a LIBOR curve, except as described below for our restructured power contracts. Additionally, contracts denominated in foreign currencies are converted to U.S. dollars using market-based, foreign exchange spot rates.

We record valuation adjustments to reflect uncertainties associated with the estimates we use in determining fair value. Common valuation adjustments include those for market liquidity and those for the credit-worthiness of our contractual counterparties. To the extent possible, we use market-based data together with quantitative methods to measure the risks for which we record valuation adjustments and to determine the level of these valuation adjustments.

The above valuation techniques are used for valuing derivative contracts that have historically been accounted for as trading activities, as well as for those that are used to hedge our natural gas and oil production. We have adjusted this method to determine the fair value of our restructured power contracts. Our restructured power derivatives use the same methodology discussed above for determining the forward settlement prices but are discounted using a risk free interest rate, adjusted for the individual credit spread for each counterparty to the contract. Additionally, no liquidity valuation adjustment is provided on these derivative contracts since they are intended to be held through maturity.

*Derivatives Designated as Hedges*

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. Hedges of cash flow exposure, which primarily relate to our natural gas and oil production hedges and foreign currency and interest rate risks on our long-term debt, are designed to hedge forecasted sales transactions or limit 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 protect the fair value of a recognized asset, liability or firm commitment. When we enter into the derivative contract, we designate the derivative as either a cash flow hedge or a fair value hedge. Our hedges of our foreign currency exposure are designated as either cash flow hedges or fair value hedges based on whether the interest on the underlying debt is converted to either a fixed or floating interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income (loss) to the extent that they are effective and are not included in 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 fair value of derivatives that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of the related hedged assets, liabilities or firm commitments.

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 whether these derivatives 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 or if we decide to discontinue the hedging relationship.

A discussion of each of our hedging activities is as follows:

*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 with the objective of realizing a fixed cash flow stream from these activities. We also have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollar. We use currency swaps to convert the fixed amounts of foreign currency due under foreign currency denominated debt to U.S. dollar amounts. As of December 31, 2004 and 2003, we have swaps that convert approximately €275 million of our debt to $255 million, substantially all of which were cancelled with the payoff of the underlying hedged debt in March 2005. A summary of the impacts of our cash flow hedges included in accumulated other comprehensive loss, net of income taxes, as of December 31, 2004 and 2003 follows.

| | Accumulated Other Comprehensive Income (Loss) | | Estimated Income (Loss) Reclassification in 2005[1] | Final Termination Date |
|---|---|---|---|---|
| | 2004 | 2003 | | |
| *Commodity cash flow hedges* | | | | |
| Held by consolidated entities | $(23) | $(72) | $ 24 | 2012 |
| Held by unconsolidated affiliates | (8) | 13 | 4 | 2006 |
| Total commodity cash flow hedges | (31) | (59) | 28 | |
| *Foreign currency cash flow hedges* | | | | |
| Fixed rate[2] | 81 | 58 | 81 | 2005 |
| Undesignated[3] | (8) | (9) | (4) | 2009 |
| Total foreign currency cash flow hedges | 73 | 49 | 77 | |
| Total[4] | $ 42 | $(10) | $105 | |

(1) Reclassifications occur upon the physical delivery of the hedged commodity and the corresponding expiration of the hedge or if the forecasted transaction is no longer probable.
(2) Substantially all of these amounts were reclassified into income with the repurchase of approximately €528 million of debt in March 2005.
(3) In December 2002, we removed the hedging designation on these derivatives related to our Euro-denominated debt.
(4) Accumulated other comprehensive income (loss) also includes $52 million and $45 million of net cumulative currency translation adjustments and $(46) million and $(24) million of additional minimum pension liability as of December 31, 2004 and 2003. All amounts are net of taxes.

In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges, specifically cash flow hedges, beginning in the fourth quarter of 2004.

For the years ended December 31, 2004, 2003 and 2002, we recognized net losses of $1 million, $2 million and $4 million, net of income taxes, in our loss from continuing operations related to the ineffective portion of all cash flow hedges.

*Fair Value Hedges.* We have fixed rate U.S. dollar and foreign currency denominated debt that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps to effectively convert the fixed amounts of interest due under the debt agreements to variable interest payments based on LIBOR plus a spread. As of December 31, 2004 and 2003, these derivatives had a net fair value of $117 million and $33 million. Specifically, we had derivatives with fair value losses of $20 million and $19 million as of December 31, 2004 and 2003, that converted the interest rate on $440 million and $350 million of our U.S. dollar denominated debt to a floating weighted average interest rate of LIBOR plus 4.2%. Additionally, we had derivatives with fair values of $137 million and $52 million as of December 31, 2004 and 2003, that converted approximately €450 million and €350 million of our debt to $511 million and $390 million. These derivatives also converted the interest rate on this debt to a floating weighted average interest rate of LIBOR plus 3.9% as of December 31, 2004, and LIBOR plus 3.7% as of December 31, 2003. We have recorded the fair value of those derivatives as a component of long-term debt and the related accrued interest. For the year ended December 31, 2002, the net financial statement impact of our fair value hedges was immaterial.

In March 2005, we repurchased approximately €528 million of debt, of which approximately €100 million were hedged with fair value hedges. As a result of the repurchase, we removed the hedging designation on, and subsequently cancelled, these derivative contracts.

In December 2002, we reduced the volumes of foreign currency exchange risk that we have hedged for our debt, and we removed the hedging designation on derivatives that had a net fair value gain of $3 million and $6 million at December 31, 2004 and 2003. These amounts, which are reflected in long-term debt, will be reclassified to income as the interest and principal on the debt are paid through 2009.

*Power Contract Restructuring Activities*

During 2001 and 2002, we conducted power contract restructuring activities that involved amending or terminating power purchase contracts at existing power facilities. In a restructuring transaction, we would eliminate the requirement that the plant provide power from its own generation to the customer of the contract (usually a regulated utility) and replace that requirement with a new contract that gave us the ability to provide power to the customer from the wholesale power market. In conjunction with these power restructuring activities, our Marketing and Trading segment generally entered into additional market-based contracts with third parties to provide the power from the wholesale power market, which effectively "locked in" our margin on the restructured transaction as the difference between the contracted rate in the restructured sales contract and the wholesale market rates on the purchase contract at the time.

Prior to a restructuring, the power plant and its related power purchase contract were accounted for at their historical cost, which was either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to the restructuring were, in most cases, accounted for on an accrual basis as power was generated and sold from the plant.

Following a restructuring, the accounting treatment for the power purchase agreement changed since the restructured contract met the definition of a derivative. In addition, since the power plant no longer had the exclusive obligation to provide power under the original, dedicated power purchase contract, it operated as a peaking merchant facility, generating power only when it was economical to do so. Because of this significant change in its use, the plant's carrying value was typically written down to its estimated fair value. These changes also often required us to terminate or amend any related fuel supply and/or steam agreements, and enter into other third party and intercompany contracts such as transportation agreements, associated with operating the merchant facility. Finally, in many cases power contract restructuring activities also involved contract terminations that resulted in cash payments by the customer to cancel the underlying dedicated power contract.

In 2002, we completed a power contract restructuring on our consolidated Eagle Point power facility and applied the accounting described above to that transaction. We also employed the principles of our power contract restructuring business in reaching a settlement of a dispute under our Nejapa power contract which included a cash payment to us. We recorded these payments as operating revenues in our Power segment. We also terminated a power contract at our consolidated Mount Carmel facility in exchange for a $50 million cash payment. For the year ended December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements (in millions):

| | Assets from Price Risk Management Activities | Liabilities from Price Risk Management Activities | Property, Plant and Equipment and Intangible Assets | Operating Revenues | Operating Expenses | Increase (Decrease) in Minority Interest[(1)] |
|---|---|---|---|---|---|---|
| Initial gain on restructured contracts | $978 | $— | $ — | $1,118 | $ — | $ 172 |
| Write-down of power plants and intangibles and other fees | — | — | (352) | — | 476 | (109) |
| Change in value of restructured contracts during 2002 | 8 | — | — | (96) | — | (20) |
| Change in value of third-party wholesale power supply contracts | — | 18 | — | (18) | — | (3) |
| Purchase of power under power supply contracts | — | — | — | — | 47 | (11) |
| Sale of power under restructured contracts | — | — | — | 111 | — | 28 |
| Total | $986 | $18 | $(352) | $1,115 | $523 | $ 57 |

(1) In our restructuring activities, third-party owners also held ownership interests in the plants and were allocated a portion of the income or loss.

As a result of our credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and are actively seeking to sell or otherwise dispose of our existing restructured power contracts. In 2004, we completed the sales of UCF (which is the restructured Eagle Point power contract) and Mohawk River Funding IV. (See Note 3 for a discussion of these sales.) Mohawk River Funding, III ("MRF III") had a prior purchase agreement ("USGen PPA") with USGen New England, Inc. ("USGen"). USGen filed for Chapter 11 bankruptcy protection and the USGen PPA was terminated automatically as a result of the bankruptcy filing. MRF III filed a proof of claim in the bankruptcy case and the bankruptcy court issued an order resolving the claim. The order is not final at this time and may be subject to change which could result in a final award that is either more or less than the receivable that has been recorded. Additionally, in March 2005, we completed the sale of Cedar Brakes I and II and the related restructured derivative power contracts.

*Other Commodity-Based Derivatives*

Our other commodity-based derivatives primarily relate to our historical trading activities, which include the services we provide in the energy sector that we entered into with the objective of generating profits on or benefiting from movements in market prices, primarily related to the purchase and sale of energy commodities. Our derivatives in our trading portfolio had a fair value liability of $61 million and $488 million as of December 31, 2004 and 2003. In December 2004, we designated a number of our other commodity-based derivative contracts with a fair value loss of $592 million as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this amount to derivatives designated as hedges beginning in the fourth quarter of 2004.

*Credit Risk*

We are subject to credit risk related to our financial instrument assets. 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 measure credit risk as the estimated replacement costs for commodities we would have to purchase or sell in the future, plus amounts owed from counterparties for delivered and unpaid commodities. These exposures are netted where we have a legally enforceable right of setoff. We maintain credit policies with regard to our counterparties in our price risk management activities to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition (including credit rating), (ii) collateral under certain circumstances (including cash in advance, letters of credit, and guarantees), (iii) the use of margining provisions in standard contracts, and (iv) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

We use daily margining provisions in our financial contracts, most of our physical power agreements and our master netting agreements, which require a counterparty to post cash or letters of credit when the fair value of the contract exceeds the daily contractual threshold. The threshold amount is typically tied to the published credit rating of the counterparty. Our margining collateral provisions also allow us to terminate a contract and liquidate all positions if the counterparty is unable to provide the required collateral. Under our margining provisions, we are required to return collateral if the amount of posted collateral exceeds the amount of collateral required. Collateral received or returned can vary significantly from day to day based on the changes in the market values and our counterparty's credit ratings. Furthermore, the amount of collateral we hold may be more or less than the fair value of our derivative contracts with that counterparty at any given period.

The following table presents a summary of our counterparties in which we had net financial instrument asset exposure as of December 31, 2004 and 2003.

| | Net Financial Instrument Asset Exposure | | | |
|---|---|---|---|---|
| Counterparty | Investment Grade(1) | Below Investment Grade(1) | Not Rated(1) | Total |
| | | (In millions) | | |
| *December 31, 2004* | | | | |
| Energy marketers | $ 440 | $ 44 | $ 35 | $ 519 |
| Natural gas and electric utilities | 424 | — | 91 | 515 |
| Other | 245 | — | 7 | 252 |
| Net financial instrument assets(2) | 1,109 | 44 | 133 | 1,286 |
| Collateral held by us | (349) | (39) | (81) | (469) |
| Net exposure from financial instrument assets | $ 760 | $ 5 | $ 52 | $ 817 |
| *December 31, 2003* | | | | |
| Energy marketers | $ 425 | $ 43 | $ 53 | $ 521 |
| Natural gas and electric utilities | 1,755 | — | 78 | 1,833 |
| Other | 106 | 1 | 75 | 182 |
| Net financial instrument assets(2) | 2,286 | 44 | 206 | 2,536 |
| Collateral held by us | (132) | (10) | (83) | (225) |
| Net exposure from financial instrument assets | $2,154 | $ 34 | $123 | $2,311 |

(1) "Investment Grade" and "Below Investment Grade" are determined using publicly available credit ratings. "Investment Grade" includes counterparties with a minimum Standard & Poor's rating of BBB− or Moody's rating of Baa3. "Below Investment Grade" includes counterparties with a public credit rating that do not meet the criteria of "Investment Grade". "Not Rated" includes counterparties that are not rated by any public rating service.

(2) Net asset exposure from financial instrument assets primarily relates to our assets and liabilities from price risk management activities. These exposures have been prepared by netting assets against liabilities on counterparties where we have a contractual right to offset. The positions netted include both current and non-current amounts and do not include amounts already billed or delivered under the derivative contracts, which would be netted against these exposures.

We have approximately 125 counterparties, most of which are energy marketers. Although most of our counterparties are not currently rated as below investment grade, if one of our counterparties fails to perform, such as in the case of Enron (see Note 17 for a further discussion of the Enron Bankruptcy), we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and quantities cannot be established.

One electric utility customer, Public Service Electric and Gas Company (PSEG), comprised 42 percent and 66 percent of our net financial instrument asset exposure as of December 31, 2004 and 2003. Our net financial instrument asset exposure to PSEG was eliminated with the sale of our interests in Cedar Brakes I and II in the first quarter of 2005. 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.

## 11. Inventory

We have the following current inventory as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Materials and supplies and other | $130 | $145 |
| NGL and natural gas in storage | 38 | 36 |
| Total current inventory | $168 | $181 |

We also have the following non-current inventory that is included in other assets in our balance sheets as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Dark fiber | $ — | $ 5 |
| Turbines | 76 | 98 |
| Total non-current inventory | $ 76 | $103 |

## 12. Regulatory Assets and Liabilities

Our regulatory assets and liabilities are included in other current and non-current assets and liabilities in our balance sheets. These balances are presented in our balance sheets on a gross basis. Below are the details of our regulatory assets and liabilities for our regulated interstate systems that apply the provisions of SFAS No. 71 as of December 31, which are recoverable over various periods:

| Description | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Current regulatory assets[(1)] | $ 3 | $ 2 |
| Non-current regulatory assets | | |
| Grossed-up deferred taxes on capitalized funds used during construction[(1)] | 85 | 77 |
| Postretirement benefits[(1)] | 30 | 32 |
| Unamortized net loss on reacquired debt[(1)] | 23 | 26 |
| Under-collected state income tax[(1)] | 7 | 4 |
| Other[(1)] | 10 | 4 |
| Total non-current regulatory assets | 155 | 143 |
| Total regulatory assets | $158 | $145 |
| Current regulatory liabilities | | |
| Cashout imbalance settlement[(1)] | $ 9 | $ 9 |
| Other | — | 2 |
| | 9 | 11 |

| Description | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Non-current regulatory liabilities | | |
| Environmental liability[1] | 97 | 87 |
| Cost of removal of offshore assets | 50 | 51 |
| Property and plant depreciation | 35 | 28 |
| Postretirement benefits[1] | 13 | 11 |
| Plant regulatory liability[1] | 11 | 11 |
| Excess deferred income taxes | 11 | 10 |
| Other | 11 | 5 |
| Total non-current regulatory liabilities | 228 | 203 |
| Total regulatory liabilities | $237 | $214 |

[1] Some of these amounts are not included in our rate base on which we earn a current return.

## 13. Other Assets and Liabilities

Below is the detail of our other current and non-current assets and liabilities on our balance sheets as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Other current assets | | |
| Prepaid expenses | $ 132 | $ 146 |
| Other | 47 | 64 |
| Total | $ 179 | $ 210 |
| Other non-current assets | | |
| Pension assets (Note 18) | $ 933 | $ 962 |
| Notes receivable from affiliates | 287 | 349 |
| Restricted cash (Note 1) | 180 | 349 |
| Unamortized debt expenses | 192 | 246 |
| Regulatory assets (Note 12) | 155 | 143 |
| Long-term receivables | 343 | 108 |
| Notes receivable | 46 | 113 |
| Turbine inventory (Note 11) | 76 | 98 |
| Other investments | 48 | 60 |
| Assets of discontinued operations | — | 405 |
| Other | 53 | 163 |
| Total | $2,313 | $2,996 |

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| **Other current liabilities** | | |
| Accrued taxes, other than income | $ 136 | $ 156 |
| Broker margin and other amounts on deposit with us | 131 | 155 |
| Income taxes | 80 | 132 |
| Environmental, legal and rate reserves (Note 17) | 84 | 96 |
| Deposits | 39 | 67 |
| Obligations under swap agreement (Note 15) | — | 49 |
| Other postretirement benefits (Note 18) | 38 | 45 |
| Asset retirement obligations (Note 1) | 28 | 26 |
| Dividends payable | 25 | 23 |
| Accrued liabilities | 74 | 49 |
| Other | 185 | 112 |
| Total | $ 820 | $ 910 |
| **Other non-current liabilities** | | |
| Environmental and legal reserves (Note 17) | $ 763 | $ 450 |
| Other postretirement and employment benefits (Note 18) | 248 | 272 |
| Obligations under swap agreement (Note 15) | — | 208 |
| Regulatory liabilities (Note 12) | 228 | 203 |
| Asset retirement obligations (Note 1) | 244 | 192 |
| Other deferred credits | 126 | 157 |
| Accrued lease obligations | 157 | 106 |
| Insurance reserves | 125 | 136 |
| Deferred gain on sale of assets to GulfTerra (Note 17) | 15 | 101 |
| Deferred compensation | 56 | 60 |
| Pipeline integrity liability (Note 22) | 50 | 69 |
| Liabilities of discontinued operations | — | 3 |
| Other | 64 | 90 |
| Total | $2,076 | $2,047 |

## 14. Property, Plant and Equipment

At December 31, 2004 and 2003, we had approximately $0.8 billion and $1.0 billion of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2004 and 2003, TGP, EPNG and ANR have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $5 billion and accumulated depreciation was approximately $1.3 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during the three years ended December 31, 2004, 2003, and 2002 was approximately $76 million, $74 million and $71 million. The adoption of SFAS No. 142 did not impact these amounts since they were included as part of our property, plant and equipment, rather than as goodwill. We do not currently earn a return on these excess purchase costs from our rate payers.

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

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Short-term financing obligations, including current maturities | $ 955 | $ 1,457 |
| Long-term financing obligations | 18,241 | 20,275 |
| Total | $19,196 | $21,732 |

Our debt and other credit facilities consist of both short and long-term borrowings with third parties and notes with our affiliated companies. During 2004, we entered into a new $3 billion credit agreement and sold entities with debt obligations. A summary of our actions is as follows (in millions):

| | |
|---|---|
| Debt obligations as of December 31, 2003 | $21,732 |
| Principal amounts borrowed[(1)] | 1,513 |
| Repayment of principal[(2)] | (3,370) |
| Sale of entities[(3)] | (887) |
| Other | 208 |
| Total debt as of December 31, 2004 | $19,196 |

[(1)] Includes proceeds from a $1.25 billion term loan under our new $3 billion credit agreement.
[(2)] Includes $850 million of repayments under our previous revolving credit facility.
[(3)] Consists of $815 million of debt related to Utility Contract Funding, L.L.C. and $72 million of debt related to Mohawk River Funding IV.

*Short-Term Financing Obligations*

We had the following short-term borrowings and other financing obligations as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Current maturities of long-term debt and other financing obligations | $948 | $1,449 |
| Short-term financing obligation | 7 | 8 |
| | $955 | $1,457 |

*Long-Term Financing Obligations*

Our long-term financing obligations outstanding consisted of the following as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Long-term debt | | |
| ANR Pipeline Company | | |
| Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025 | $ 800 | $ 800 |
| Notes, 13.75% due 2010 | 12 | 13 |
| Colorado Interstate Gas Company | | |
| Debentures, 6.85% through 10.0%, due 2005 and 2037 | 280 | 280 |
| El Paso CGP Company | | |
| Senior notes, 6.2% through 7.75%, due 2004 through 2010 | 930 | 1,305 |
| Senior debentures, 6.375% through 10.75%, due 2004 through 2037 | 1,357 | 1,395 |
| El Paso Corporation | | |
| Senior notes, 5.75% through 7.125%, due 2006 through 2009 | 1,956 | 1,817 |
| Equity security units, 6.14% due 2007 | 272 | 272 |
| Notes, 6.625% through 7.875%, due 2005 through 2018 | 1,952 | 2,002 |
| Medium-term notes, 6.95% through 9.25%, due 2004 through 2032 | 2,784 | 2,812 |
| Zero coupon convertible debentures due 2021 | 822 | 895 |
| $3 billion revolver, LIBOR plus 3.5% due June 2005 | — | 850 |
| $1.25 billion term loan, LIBOR plus 2.75% due 2009 | 1,245 | — |
| El Paso Natural Gas Company | | |
| Notes, 7.625% and 8.375%, due 2010 and 2032 | 655 | 655 |
| Debentures, 7.5% and 8.625%, due 2022 and 2026 | 460 | 460 |
| El Paso Production Holding Company | | |
| Senior notes, 7.75%, due 2013 | 1,200 | 1,200 |

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Power | | |
| Non-recourse senior notes, 7.75% through 9.875%, due 2008 through 2014 | 666 | 770 |
| Non-recourse notes, variable rates, due 2007 and 2008 | 320 | 361 |
| Recourse notes, 7.27% and 8.5%, due 2005 and 2016 | 40 | 85 |
| Gemstone notes, 7.71% due 2004 | — | 950 |
| Non-recourse financing—UCF, 7.944%, due 2016 | — | 829 |
| Southern Natural Gas Company | | |
| Notes and senior notes, 6.125% through 8.875%, due 2007 through 2032 | 1,200 | 1,200 |
| Tennessee Gas Pipeline Company | | |
| Debentures, 6.0% through 7.625%, due 2011 through 2037 | 1,386 | 1,386 |
| Notes, 8.375%, due 2032 | 240 | 240 |
| Other | 137 | 404 |
| | 18,714 | 20,981 |
| Other financing obligations | | |
| Capital Trust I | 325 | 325 |
| Coastal Finance I | 300 | 300 |
| Lakeside Technology Center lease financing loan due 2006 | — | 275 |
| | 625 | 900 |
| Subtotal | 19,339 | 21,881 |
| Less: | | |
| Unamortized discount and premium on long-term debt | 150 | 157 |
| Current maturities | 948 | 1,449 |
| Total long-term financing obligations, less current maturities | $18,241 | $20,275 |

During 2004 and to date in 2005, we had the following changes in our long-term financing obligations:

| Company | Type | Interest Rate | Principal (In millions) | Due Date |
|---|---|---|---|---|
| *Issuances and other increases* | | | | |
| Macae | Non-recourse note | LIBOR + 4.25% | $ 50 | 2007 |
| Blue Lake Gas Storage[1] | Non-recourse term loan | LIBOR + 1.2% | 14 | 2006 |
| El Paso[2] | Notes | 6.50% | 213 | 2005 |
| El Paso[3] | Term loan | LIBOR + 2.75% | 1,250 | 2009 |
| Increases through December 31, 2004 | | | $1,527 | |
| Colorado Interstate Gas Company | Senior Notes | 5.95% | 200 | 2015 |
| Increases through March 25, 2005 | | | $1,727 | |
| *Repayments, repurchases and other retirements* | | | | |
| El Paso CGP | Note | LIBOR + 3.5% | $ 200 | |
| El Paso | Revolver | LIBOR + 3.5% | 850 | |
| El Paso CGP | Note | 6.2% | 190 | |
| Mohawk River Funding IV[4] | Non-recourse note | 7.75% | 72 | |
| Utility Contract Funding[4] | Non-recourse senior notes | 7.944% | 815 | |
| Gemstone | Notes | 7.71% | 950 | |
| Lakeside | Note | LIBOR + 3.5% | 275 | |
| El Paso CGP | Senior Debentures | 10.25% | 38 | |
| El Paso[2] | Notes | 6.50% | 213 | |
| El Paso[5] | Zero coupon debenture | — | 109 | |
| El Paso | Notes | Various | 49 | |
| El Paso CGP | Notes | Various | 185 | |
| El Paso | Medium-term notes | Various | 28 | |
| Other | Long-term debt | Various | 283 | |
| Decreases through December 31, 2004 | | | 4,257 | |
| El Paso[5] | Zero coupon debenture | — | 185 | |
| Cedar Brakes I[4] | Non-recourse notes | 8.5% | 286 | |
| Cedar Brakes II[4] | Non-recourse notes | 9.88% | 380 | |
| El Paso[6] | Euros | 5.75% | 715 | |
| Other | Long-term debt | Various | 96 | |
| Decreases through March 25, 2005 | | | $5,919 | |

(1) This debt was consolidated as a result of adopting FIN No. 46 (see Note 2).

(2) In the fourth quarter of 2004, we entered into an agreement with Enron that liquidated two derivative swap agreements of approximately $221 million in exchange for approximately $213 million of 6.5% one year notes. Subsequent to the closing of our new credit agreement, these notes were paid in full.

(3) Proceeds from the $1.25 billion term loan under the new credit agreement entered into in November 2004.

(4) The remaining balance of these debt obligations was eliminated when we sold our interests in Mohawk River Funding IV, UCF and Cedar Brakes I and II.

(5) In December 2004 and January 2005, we repurchased these 4% yield-to-maturity zero-coupon debentures. The amount shown as principal is the carrying value on the date the debt was retired as compared to its maturity value in 2021 of $206 million in December 2004, and $351 million in January 2005.

(6) In March 2005, we repaid debt with a principal balance of €528 million, which had a carrying value of $724 million in long-term debt on our balance sheet as of December 31, 2004. In conjunction with this repayment, we also terminated derivative contracts with a fair value of $152 million as of December 31, 2004 that hedged this debt. The total net payment was $579 million. See Note 10 for additional information on the repurchase of the derivative contracts.

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

| | |
|---|---|
| 2005 | $ 948 |
| 2006[(1)] | 1,155 |
| 2007 | 835 |
| 2008 | 733 |
| 2009 | 2,637 |
| Thereafter | 13,031 |
| Total long-term financing obligations, including current maturities | $19,339 |

(1) Excludes $0.8 billion of zero coupon debentures as discussed below.

Included above in 2005 is $320 million of debt associated with our Macae project in Brazil, as a result of an event of default on Macae's non-recourse debt. (See Note 17 for additional details on the event of default.) Also included in 2005 are approximately $114 million of notes and debentures that holders have the option to redeem in 2005, prior to their stated maturities. Of this amount, $75 million is eligible for redemption solely in 2005 and, if not redeemed, will be reclassified to long-term debt in 2006.

Included in the "thereafter" line of the table above are $600 million of other debentures that holders have an option to redeem in 2007 prior to their stated maturities and $822 million of zero coupon convertible debentures. The zero-coupon debentures have a maturity value of $1.6 billion, are due 2021 and have a yield to maturity of 4 percent. The holders can cause us to repurchase these debentures at their option in years 2006, 2011 and 2016, should they make this election, we can choose to settle in cash or common stock at a price which approximates market. These debentures are convertible into 7,468,726 shares of our common stock, which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate is equal to a conversion price of $94.604 per share of our common stock.

*Credit Facilities*

In November 2004, we replaced our previous $3 billion revolving credit facility, which was scheduled to mature in June 2005, with a new $3 billion credit agreement with a group of lenders. This $3 billion credit agreement consists of a $1.25 billion five-year term loan; a $1 billion three-year revolving credit facility; and a $750 million, five-year letter of credit facility. Certain of our subsidiaries, EPNG, TGP, ANR and CIG, also continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement, which is collateralized by our interests in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company and Southern Gas Storage Company.

As of December 31, 2004, we had $1.25 billion outstanding under the term loan and had utilized approximately all of the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to issue letters of credit. The term loan accrues interest at LIBOR plus 2.75 percent, matures in November 2009, and will be repaid in increments of $5 million per quarter with the unpaid balance due at maturity. Under the new revolving credit facility, which matures in November 2007, we can borrow funds at LIBOR plus 2.75 percent or issue letters of credit at 2.75 percent plus a fee of 0.25 percent of the amount issued. We pay an annual commitment fee of 0.75 percent on any unused capacity under the revolving credit facility. The terms of the new $750 million letter of credit facility provides us the ability to issue letters of credit or borrow any unused capacity under the letter of credit facility as revolving loans with a maturity in November 2009. We pay LIBOR plus 2.75 percent on any amounts borrowed under the letter of credit facility, and 2.85 percent on letters of credit and unborrowed funds.

*Restrictive Covenants*

Our restrictive covenants includes restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our new credit agreement the significant debt covenants and cross defaults are:

(a) El Paso's ratio of Debt to Consolidated EBITDA, each as defined in the new credit agreement, shall not exceed 6.50 to 1.0 at any time prior to September 30, 2005, 6.25 to 1.0 at any time on or after September 30, 2005 and prior to June 30, 2006, and 6.00 to 1.0 at any time on or after June 30, 2006 until maturity;

(b) El Paso's ratio of Consolidated EBITDA, as defined in the new credit agreement, to interest expense plus dividends paid shall not be less than 1.60 to 1.0 prior to March 31, 2006, 1.75 to 1.0 on or after March 31, 2006 and prior to March 31, 2007, and 1.80 to 1.0 on or after March 31, 2007 until maturity;

(c) EPNG, TGP, ANR, and CIG cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the new credit agreement, for that particular company to exceed 5 to 1;

(d) the proceeds from the issuance of Debt by our pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt; and

(e) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to Debt in an aggregate principal amount of $200 million or more.

In addition to the above restrictions and default provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in our cash management program, and limitations on our ability to prepay debt.

We also issued various guarantees securing financial obligations of our subsidiaries and unaudited affiliates with similar covenants as the above facilities.

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $850 million. If breached, the amounts guaranteed by its guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of such subsidiaries in excess of $5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

*Other Financing Arrangements*

*Capital Trust I.* In March 1998, we formed El Paso Energy Capital Trust I, a wholly owned subsidiary, which issued 6.5 million of 4.75 percent trust convertible preferred securities for $325 million. We own all of the Common Securities of Trust I. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued due 2028, their sole asset. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay the obligations on Trust I's preferred securities. We provide a full and unconditional guarantee of Trust I's preferred securities.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 percent, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I preferred security (equivalent to a conversion price of $41.59 per common share). During 2003, the outstanding amounts of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

*Coastal Finance I.* Coastal Finance I is an indirect wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for $300 million. Coastal Finance I holds subordinated debt securities issued by our wholly owned subsidiary, El Paso CGP, that it 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 percent of the liquidation amount of $25 per preferred security. Coastal Finance I's only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I's preferred securities. 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. The redemption price to be paid is $25 per preferred security, plus accrued and unpaid distributions to the date of redemption. El Paso CGP provides a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available. We have no obligation to provide funds to Coastal Finance I for the payment of or redemption of the preferred securities outside of our obligation to pay interest and principal on the subordinated debt securities. During 2003, the amounts outstanding of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

*Equity Security Units.* In June 2002, we issued 11.5 million, 9 percent equity security units. Equity security units consist of two securities: i) a purchase contract on which we pay quarterly contract adjustment payments at an annual rate of 2.86 percent and that requires its holder to buy our common stock on a stated settlement date of August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we pay quarterly interest payments at an annual rate of 6.14 percent. The senior notes we issued had a total principal value of $575 million and are pledged to secure the holders' obligation to purchase shares of our common stock under the purchase contracts. In December 2003, we completed a tender offer to exchange 6,057,953 of the outstanding equity security units, which represented approximately 53 percent of the total units outstanding. In the exchange, we issued a total of 15,182,972 shares of our common stock that had a total market value of $119 million, and paid $59 million in cash.

When the remaining purchase contracts are settled in 2005, the contract provides for us to issue common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior consecutive 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 11 million shares and up to a maximum of approximately 14 million shares on the settlement date, depending on our average stock price.

*Non-Recourse Project Financings.* Many of our power subsidiaries and investments have borrowed a material portion of the costs to acquire or construct their domestic and international power assets. Such borrowings are made with recourse only to the project company and assets (i.e. without recourse to El Paso). On occasion, events have occurred in connection with several of our projects that have either constituted an event of default under the loan agreements or could constitute an event of default upon delivery of a notice from the lenders and the failure of the subsidiary or investee to cure the event during an applicable grace period. Currently, we have one consolidated subsidiary, Macae, where the power off taker to the project, Petrobras, has not paid all amounts owed under its contract with the plant. This non-payment has created an event of default on that project under its loan agreements. Accordingly, we classified approximately $320 million as current debt as of December 31, 2004. (See Note 17 for additional information on our investment in Macae.) In addition, we have several other projects that we account for as equity investments that are in default under their loan agreements, including Saba, Berkshire and East Asia Power. We have written off all of our investment in both the Berkshire and East Asia Power facilities and have a $9 million interest in Saba. There is no recourse to El Paso under the loans at these investments. In addition, we have had events of default or other events that could lead to an event of default upon notice from the lenders on other projects, but we do not believe any of these defaults will have a material impact on our or our subsidiaries' financial statements.

*Letters of Credit*

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2004, we had outstanding letters of credit of approximately $1.3 billion, of which $107 million was supported with cash collateral, and $1.2 billion were issued under our credit agreement. Included in this amount were $0.9 billion of letters of credit securing our recorded obligations related to price risk management activities.

*Available Capacity Under Shelf Registration Statements*

We maintain a shelf registration statement with the SEC that allows us to issue a combination of debt, equity and other instruments, including trust preferred securities of two wholly owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we would be required to issue full and unconditional guarantees on these securities. As of December 31, 2004, we had $926 million remaining capacity under this shelf registration statement; however, we are unable to access this capacity until January 2006, due to the untimely filing of our 2003 annual and quarterly 2004 financial statements.

## 16. Preferred Interests of Consolidated Subsidiaries

In the past, we entered into financing transactions that have been accomplished through the sale of preferred interests in consolidated subsidiaries. During 2003, we repaid approximately $2 billion of these preferred interests, reclassified $625 million to long-term financing obligations as a result of adopting SFAS No. 150 (see Note 1) and eliminated $300 million in consolidation because we acquired the holder of those preferred interests. Our remaining preferred interest is discussed below.

*El Paso Tennessee Preferred Stock.* In 1996, El Paso Tennessee Pipeline Co. (EPTP) issued 6 million shares of publicly registered 8.25 percent cumulative preferred stock with a par value of $50 per share for $300 million. The preferred stock is redeemable, at our option, at a redemption price equal to $50 per share, plus accrued and unpaid dividends, at any time. EPTP indirectly owns our marketing and trading businesses, substantially all of our domestic and international power businesses, and TGP. While not required, the following financial information is intended to provide additional information of EPTP to its preferred security holders:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | | (In millions) (unaudited) | |
| Operating results data: | | | |
| Operating revenues | $ 812 | $1,459 | $ 1,132 |
| Operating expenses | 1,131 | 1,865 | 2,268 |
| Loss from continuing operations | (399) | (377) | (1,288) |
| Net loss | (399) | (377) | (1,510) |

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| | (In millions) (unaudited) | |
| Financial position data: | | |
| Current assets | $2,783 | $ 4,217 |
| Non-current assets | 9,001 | 9,892 |
| Short-term debt | 402 | 1,111 |
| Other current liabilities | 4,693 | 5,409 |
| Long-term debt | 2,183 | 2,545 |
| Other non-current liabilities | 2,580 | 2,642 |
| Securities of subsidiaries | 3 | 28 |
| Equity in net assets | 1,923 | 2,374 |

## 17. Commitments and Contingencies

*Legal Proceedings*

*Western Energy Settlement.* In June 2004, our master settlement agreement, along with other separate settlement agreements, became effective with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada. This resolves the principal litigation, investigations, claims and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western U.S. (the Western Energy Settlement). As part of the Western Energy Settlement, we admitted no wrongdoing but agreed, among other things, to make various cash payments and modify an existing power supply contract. We also entered into a Joint Settlement Agreement or JSA where we agreed, subject to the limitations in the JSA, to (1) make 3.29 Bcf/d of capacity available to California to the extent shippers sign firm contracts for that capacity, (2) maintain facilities sufficient to physically deliver 3.29 Bcf/d to California; (3) construct facilities which we completed in 2004, (4) clarify certain shippers' recall rights on the system and (5) bar any of our affiliated companies from obtaining additional firm capacity on our EPNG pipeline system during a five year period from the effective date of the settlement.

In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA described above with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia, where this matter is pending. We expect this appeal to be fully briefed by the summer of 2005.

During the fourth quarter of 2002, we recorded an $899 million pretax charge related to the Western Energy Settlement. During 2003, we recorded additional pretax charges of $104 million based upon reaching definitive settlement agreements. Charges and expenses associated with the Western Energy Settlement are included in operations and maintenance expense in our consolidated statements of income. When the settlement became effective in June 2004, $602 million was released to the settling parties. This amount is shown as a reduction of our cash flows from operations in the second quarter of 2004. Of the amount released, $568 million had been previously held in an escrow account pending final approval of the settlement. The release of these restricted funds is included as an increase in our cash flows from investing activities. Our remaining obligation as of December 31, 2004 under the Western Energy Settlement consists of a discounted 20-year cash payment obligation of $395 million and a price reduction under a power supply contract, which is included in our price risk management activities. In connection with the Western Energy Settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining cash payment obligation. The collateral requirement is being reduced as payments under the 20 year obligation are made. For an issue regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 7.

*Shareholder/Derivative/ERISA Litigation*

*Shareholder Litigation.* Since 2002, twenty-nine purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our current and former officers and directors. One of these lawsuits has been dismissed and the remaining 28 lawsuits have been consolidated in federal court in Houston, Texas. The consolidated lawsuit generally challenges the accuracy or completeness of press releases and other public statements made during the class period from 2001 through early 2004, related to wash trades, mark-to-market accounting, off-balance sheet debt, overstatement of oil and gas reserves and manipulation of the California energy market. The consolidated lawsuit is currently stayed.

*Derivative Litigation.* Since 2002, five shareholder derivative actions have also been filed. Three of the actions allege the same claims as in the consolidated shareholder class action suit described above, with one of the actions including a claim for compensation disgorgement against certain individuals. These actions are currently stayed. Two actions are now consolidated in state court in Houston, Texas and generally allege that manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value.

*ERISA Class Action Suits.* In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. This lawsuit has been stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits. There are certain deductibles and co-pay obligations under some of those insurance coverages for which we have established certain accruals we believe are adequate.

*Cash Balance Plan Lawsuit.* In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

*Retiree Medical Benefits Matters.* We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Company and Case Corporation*. The suit alleges, among other things, that El Paso violated ERISA, and that Case should be required to pay all amounts above the cap. Although such amounts will vary over time, the amounts above the cap have recently been approximately $1.8 million per month. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend, and hold Case harmless for the amounts it would be required to pay. In February 2004, a judge ruled that Case would be required to pay the amounts incurred above the cap. Furthermore, in September 2004, a judge ruled that pending resolution of this matter, El Paso must indemnify and reimburse Case for the monthly amounts above the cap. Our motion for reconsideration of these orders was denied in November 2004. These rulings have been appealed. In the meantime, El Paso will indemnify Case for any payments Case makes above the cap. While we believe we have meritorious defenses to the plaintiffs' claims and to Case's crossclaim, if we were required to ultimately pay for all future amounts above the cap, and if Case were not found to be responsible for these amounts, our exposure could be as high as $400 million, on an undiscounted basis.

*Natural Gas Commodities Litigation.* Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. In January 2005 a purported class action lawsuit styled *Leggett et al. v Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of the all residential and commercial purchasers of natural gas in the state of Tennessee during the past three years. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. The Company has also had similar claims asserted by individual commercial customers. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Grynberg.* A number of our subsidiaries were named defendants in actions filed in 1997 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 underreport 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. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. 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). Motions to dismiss have been filed on behalf of all defendants. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Will Price (formerly Quinque).* A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys' fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action has since been filed as to the heating content claims. The plaintiffs have filed motions for class certification in both proceedings and the defendants have filed briefs in opposition thereto. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Bank of America.* We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs seek an accounting and damages for alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in

Oklahoma, plus interest from the time such amounts were allegedly due, as well as punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners, and the parties have completed discovery. The plaintiffs have filed expert reports alleging damages in excess of $1 billion. Pursuant to a recent summary judgment decision, the court ruled that claims previously released by the settlement of *Altheide v. Meridian,* a nation-wide royalty class action against Burlington and its affiliates are barred from being reasserted in this action. We believe that this ruling eliminates a material, but yet unquantified portion of the alleged class damages. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Resources, Inc., and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity by Burlington. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Araucaria.* We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $186 million at December 31, 2004. We have political risk insurance that covers a portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

*Macae.* We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil with property, plant and equipment having a net book value of $700 million as of December 31, 2004. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are paid by Petrobras until August 2007 under a participation agreement. Petrobras failed to make any payments that were due under the participation agreement for December 2004 and January 2005. In 2005, Petrobras obtained a ruling from a Brazilian court directing Petrobras to deposit one-half of the payments to a court account and to pay us the other half. We are appealing this ruling. Petrobras has also failed to make any payments required under the court order. As of December 31, 2004, our accounts receivable balance is approximately $20 million. Petrobras has also filed a notice of arbitration with an international arbitration institution that effectively seeks rescission of the participation agreement and reimbursement of a portion of the capacity payments that it has made. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras's obligation to provide a firm gas supply to the project through 2012. We believe we have substantial defenses to the claims of Petrobras and will vigorously defend our legal rights. In addition, we will continue to seek reasonable negotiated settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $320 million at December 31, 2004, and Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $320 million of debt as current. We also have restricted cash balances of approximately $76 million as of December 31, 2004, which are reflected in current assets, related to required debt service reserve balances, debt service payment accounts and funds held for future distribution by Macae. We have also issued cash collateralized letters of credit of approximately $47 million as part of funding the required debt service reserve accounts. The restricted cash related to these letters of credit has also been classified as a current asset. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise certain remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

In light of the pending arbitration proceedings, we have evaluated whether any impairment of our investment in the project is required at December 31, 2004. Based upon our review of the possible outcomes of the arbitration and potential settlements of the dispute, we do not believe that an impairment of our investment is required at this time. However, if our assessment of the potential outcomes of the arbitration or settlement opportunities changes, we may be required to write down some or all of our investment in the project. In the event that the lenders call the loans and ultimately foreclose on the project, our loss would be approximately $500 million as of December 31, 2004. As new information becomes available or future material developments occur, we will reassess our carrying value of this investment.

*MTBE.* In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. Our costs and legal exposure related to these lawsuits are not currently determinable.

*Wise Arbitration.* William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached employment and other agreements by failing to make certain payments to him following his departure from El Paso in 2003. Discovery is underway, with a hearing scheduled in the summer of 2005.

*Government Investigations*

*Power Restructuring.* In October 2003, we announced that the SEC had authorized the staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We have cooperated with the SEC investigation.

*Wash Trades.* In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning round trip or wash trades. We have complied with those requests. We have also cooperated with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production and the restatement of such hedges.

*Price Reporting.* In October 2002, the FERC issued data requests regarding price reporting of transactional data to the energy trade press. We provided information to the FERC, the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney's investigation of this matter.

*Reserve Revisions.* In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand jury subpoenas for documents with regard to these reserve revisions. We are cooperating with the SEC's and the U.S. Attorney's investigations of this matter.

*Storage Reporting.* In November 2004, ANR and TGP received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the Energy Information Administration (EIA) for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR and TGP provided information on their weekly EIA submissions for two weeks in November 2004. Neither ANR nor TGP's submissions to the EIA were revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC and ANR provided the requested information. On December 17, 2004, the FERC held a press conference in which they disclosed that their inquiry had determined that an unaffiliated third party was the source of the downward revision.

*Iraq Oil Sales.* In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations' Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records relating to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement in connection with Coastal and El Paso's participation in the Oil for Food Program. We have also received informal requests for information and documents from the United States Senate's Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to Coastal's purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney's, the SEC's, the Senate Subcommittee's, and the House Committee's investigations of this matter.

*Carlsbad.* In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged five violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. EPNG has fully accrued for these fines. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations. In December 2003, the matter was referred to the Department of Justice.

After a public hearing conducted by the National Transportation Safety Board (NTSB) on its investigation into the Carlsbad rupture, the NTSB published its final report in April 2003. The NTSB stated that it had determined that the probable cause of the August 2000 rupture was a significant reduction in pipe wall thickness due to severe internal corrosion, which occurred because EPNG's corrosion control program "failed to prevent, detect, or control internal corrosion" in the pipeline. The NTSB also determined that ineffective federal preaccident inspections contributed to the accident by not identifying deficiencies in EPNG's internal corrosion control program.

In November 2002, EPNG received a federal grand jury subpoena for documents related to the Carlsbad rupture and cooperated fully in responding to the subpoena. That subpoena has since expired. In December 2003 and January 2004, eight current and former employees were served with testimonial subpoenas issued by the grand jury. Six individuals testified in March 2004. In April 2004, we and EPNG received a new federal grand jury subpoena requesting additional documents. We have responded fully to this subpoena. Two additional employees testified before the grand jury in June 2004.

A number of civil actions were filed against EPNG in connection with the rupture which have now been settled or should be fully covered by insurance.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

*Rates and Regulatory Matters*

*Pipeline Integrity Costs.* In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $25 million to $41 million annually over the next eight years.

*Inquiry Regarding Income Tax Allowances.* In December 2004, the FERC issued a Notice of Inquiry (NOI) in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC sought comments on whether the court's reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines, including those pipelines which are jointly owned with unaffiliated parties.

*Selective Discounting Notice of Inquiry.* In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

*Other Contingencies*

*Enron Bankruptcy.* In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. (ENA) and Enron Power Marketing, Inc. (EPMI) filed for Chapter 11 bankruptcy protection in New York. We had various contracts with Enron marketing and trading entities, and most of the trading-related contracts were terminated due to the bankruptcy. In October 2002, we filed proofs of claims against the Enron trading entities totaling approximately $317 million.

*Enron Trading Claims.* We have largely sold or settled all of our original claims of our trading entities with Enron. In particular, on June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved most of our trading or merchant issues between the parties for which final payments were made in the third quarter of 2004. The only remaining trading claims involve our European trading businesses, claims against Enron Capital and Trade Resources Limited, which are subject to separate proceedings in the United Kingdom, in addition to a corresponding claim against Enron Corp. based on a corporate guarantee. After considering the valuation and setoff arguments and the reserves we have established, we believe our overall remaining trading exposure to Enron is $3 million.

*Enron Pipeline Claims.* In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts were rejected, and our pipeline subsidiaries filed proofs of claim totaling approximately $137 million. EPNG filed the largest proof of claim in the amount of approximately $128 million, which included $18 million for amounts due for services provided through the date the contracts were rejected and $110 million for damage claims arising from the rejection of its transportation contracts. EPNG expects that Enron will vigorously contest these claims. Our remaining pipeline claimants, ANR TGP and WIC, are in various stages of attempting to resolve their claims with Enron. Given the uncertainty of the bankruptcy process, the results are uncertain. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any amounts under these contracts since that time.

*Brazilian Matters.* We own a number of interests in various production properties, power and pipeline assets in Brazil. Our total investment in Brazil was approximately $1.6 billion as of December 31, 2004.

Although economic conditions have generally improved over the last year, Brazil has experienced high interest rates on local debt and has experienced restrictions on the availability of foreign funds and investment. In addition, in a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. We also own an investment in a power plant in Brazil called Porto Velho. The Porto Velho project is in the process of negotiating certain provisions of its PPAs with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant's capacity. The project expects to replace or repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs. Although the current terms of the PPAs and the proposed amendments do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was $292 million at December 31, 2004.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the item, our exposure to the matter, 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, then we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of December 31, 2004, we had approximately $592 million net of related insurance receivables accrued for our outstanding legal and other contingencies, including amounts accrued for our Western Energy Settlement.

*Environmental Matters*

We are subject to 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, 2004, we had accrued approximately $380 million, including approximately $373 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $7 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $380 million accrual, $100 million was reserved for facilities we currently operate, and $280 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $380 million to approximately $547 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($82 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($298 million to $465 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

| | December 31, 2004 | |
|---|---|---|
| **Sites** | **Expected** | **High** |
| | **(In millions)** | |
| Operating | $100 | $111 |
| Non-operating | 249 | 384 |
| Superfund | 31 | 52 |
| Total | $380 | $547 |

Below is a reconciliation of our accrued liability from January 1, 2004, to December 31, 2004 (in millions):

| | |
|---|---|
| Balance as of January 1, 2004 | $412 |
| Additions/adjustments for remediation activities | 17 |
| Payments for remediation activities | (51) |
| Other changes, net | 2 |
| Balance as of December 31, 2004 | $380 |

For 2005, we estimate that our total remediation expenditures will be approximately $64 million. In addition, we expect to make capital expenditures for environmental matters of approximately $62 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

*Internal PCB Remediation Project.* Since 1988, TGP, our subsidiary, has been engaged in an internal project to identify and address the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the EPA List of Hazardous Substances (HSL), at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations, and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at its Pennsylvania and New York stations.

*PCB Cost Recoveries.* In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of December 31, 2004, TGP had pre-collected PCB costs by approximately $125 million. This pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of December 31, 2004, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $97 million for estimated future refund obligations.

*CERCLA Matters.* We 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 61 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 sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2004, we have estimated our share of the remediation costs at these sites to be between $31 million and $52 million. 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 estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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 our current environmental reserves are adequate.

Commitments and Purchase Obligations

*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 2005 until 2053. As of December 31, 2004, our total commitments under operating leases were approximately $442 million. Minimum annual rental commitments under our operating leases at December 31, 2004, were as follows:

| Year Ending December 31, | Operating Leases (In Millions) |
|---|---|
| 2005 | $ 79 |
| 2006 | 66 |
| 2007 | 51 |
| 2008 | 43 |
| 2009 | 40 |
| Thereafter | 163 |
| Total | $442 |

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $28 million due in the future under noncancelable subleases. Rental expense on our operating leases for the years ended December 31, 2004, 2003 and 2002 was $101 million, $113 million and $116 million.

In May 2004, we announced we would consolidate our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004 we have established an accrual totaling $80 million to record the liability, net of sublease rentals, for our obligations under our existing lease terms. We currently lease approximately 888,000 square feet of office space in the buildings we are vacating under various leases with lease terms expiring through 2014. See Note 4 for additional information regarding these lease terminations.

*Guarantees.* We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include indemnification for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

We evaluate at the time a guarantee or indemnity arrangement is entered into and in each period thereafter whether a liability exists and, if so, if it can be estimated. We record accruals when both these criteria are met. As of December 31, 2004, we had accrued $70 million related to these arrangements. As of December 31, 2004, we had approximately $40 million of financial and performance guarantees, and indemnification arrangements not otherwise reflected in our financial statements.

*Other Commercial Commitments.* We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2004, we had firm commitments under tolling, transportation and storage capacity contracts of $1.5 billion, commodity purchase commitments of $149 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $224 million.

## 18. Retirement Benefits

*Pension Benefits*

Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat or Coastal receive the greater of cash balance benefits or transition benefits under the prior plan formulas. Transition benefits reflect prior plan accruals for these employees through December 31, 2001, December 31, 2004 and March 31, 2006. We do not anticipate making any contributions to this pension plan in 2005.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We also maintain two other pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. The SERP and the frozen plans together are referred to below as other pension plans. We also participate in one multi-employer pension plan for the benefit of our former employees who were union members. Our contributions to this plan during 2004, 2003 and 2002 were not material. We expect to contribute $5 million to the SERP in 2005. We do not anticipate making any contributions to our other pension plans in 2005.

During 2004, we recognized a $4 million curtailment benefit in our pension plans primarily related to a reduction in the number of employees that participate in our pension plan, which resulted from our various asset sales and employee severance efforts. During 2003, we recognized $11 million in charges in our pension plans that resulted from employee terminations and our internal reorganization.

*Retirement Savings Plan*

We maintain a defined contribution plan covering all of our U.S. employees. Prior to May 1, 2002, we matched 75 percent of participant basic contributions up to 6 percent, with the matching contributions being made to the plan's stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, we suspended the matching contributions, but reinstituted it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, we increased the matching contributions to 75 percent of participant basic contributions up to 6 percent. Amounts expensed under this plan were approximately $16 million, $14 million and $28 million for the years ended December 31, 2004, 2003 and 2002.

*Other Postretirement Benefits*

We provide postretirement medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. We expect to contribute $63 million to our postretirement plans in 2005. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits.

Below is our projected benefit obligation, accumulated benefit obligation, fair value of plan assets as of September 30, our plan measurement date, and related balance sheet accounts for our pension plans as of December 31:

| | Primary Pension Plan | | Other Pension Plans | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| | (In millions) | | | |
| Projected benefit obligation | $1,948 | $1,928 | $170 | $163 |
| Accumulated benefit obligation | 1,934 | 1,902 | 169 | 163 |
| Fair value of plan assets | 2,196 | 2,104 | 93 | 93 |
| Accrued benefit liability | — | — | 74 | 69 |
| Prepaid benefit cost | 960 | 960 | — | 21 |
| Accumulated other comprehensive loss | — | — | 70 | 37 |

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| Projected benefit obligation | $170 | $134 |
| Accumulated benefit obligation | 169 | 134 |
| Fair value of plan assets | 93 | 63 |

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded other comprehensive income (loss) of $(33) million in 2004 and $18 million in 2003 related to the change in this additional minimum liability.

Below is the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our pension and other postretirement benefit plans. Our benefits are presented and computed as of and for the twelve months ended September 30.

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| | (In millions) | | | |
| Change in benefit obligation: | | | | |
| Projected benefit obligation at beginning of period | $2,091 | $2,088 | $ 575 | $ 558 |
| Service cost | 31 | 36 | 1 | 1 |
| Interest cost | 121 | 134 | 34 | 35 |
| Participant contributions | — | — | 27 | 24 |
| Settlements, curtailments and special termination benefits | (3) | — | — | (6) |
| Actuarial loss (gain) | 76 | 22 | (20) | 50 |
| Benefits paid | (198) | (189) | (76) | (87) |
| Projected benefit obligation at end of period | $2,118 | $2,091 | $ 541 | $ 575 |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of period | $2,197 | $2,072 | $ 196 | $ 164 |
| Actual return on plan assets | 277 | 285 | 12 | 25 |
| Employer contributions | 12 | 29 | 61 | 70 |
| Participant contributions | — | — | 27 | 24 |
| Benefits paid | (198) | (189) | (76) | (87) |
| Administrative expenses | 1 | — | — | — |
| Fair value of plan assets at end of period | $2,289 | $2,197 | $ 220 | $ 196 |

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| | (In millions) | | | |
| Reconciliation of funded status: | | | | |
| Fair value of plan assets at September 30 | $2,289 | $2,197 | $ 220 | $ 196 |
| Less: Projected benefit obligation at end of period | 2,118 | 2,091 | 541 | 575 |
| Funded status at September 30 | 171 | 106 | (321) | (379) |
| Fourth quarter contributions and income | 2 | 2 | 13 | 17 |
| Unrecognized net actuarial loss[1] | 800 | 868 | 32 | 57 |
| Unrecognized net transition obligation | — | 1 | 8 | 15 |
| Unrecognized prior service cost | (17) | (28) | (6) | (7) |
| Prepaid (accrued) benefit cost at December 31 | $ 956 | $ 949 | $(274) | $(297) |

(1) The decrease in unrecognized net actuarial loss in our pension benefits was primarily due to historical changes and assumptions on discount rates, expected return on plan assets and rate of compensation increase. We recognize the difference between the actual return and our expected return over a three year period as permitted by SFAS No. 87. The decrease in unrecognized net actuarial loss in our other postretirement benefits was primarily due to the adoption of FSP No. 106-2.

The portion of our other postretirement benefit obligation included in current liabilities was $38 million and $45 million as of December 31, 2004 and 2003.

Future benefits expected to be paid from our pension plans and our other postretirement plans as of December 31, 2004, are as follows:

| Year Ending December 31, | Pension Benefits | Other Postretirement Benefits[1] |
|---|---|---|
| | (In millions) | |
| 2005 | $ 160 | $ 57 |
| 2006 | 160 | 52 |
| 2007 | 161 | 50 |
| 2008 | 161 | 48 |
| 2009 | 160 | 46 |
| 2010-2014 | 788 | 208 |
| Total | $1,590 | $461 |

(1) Includes a reduction of $3 million in each year excluding 2005 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

For each of the years ended December 31, the components of net benefit cost (income) are as follows:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (In millions) | | | | | |
| Service cost | $ 31 | $ 36 | $ 33 | $ 1 | $ 1 | $ 2 |
| Interest cost | 121 | 134 | 135 | 34 | 35 | 38 |
| Expected return on plan assets | (187) | (227) | (260) | (11) | (9) | (9) |
| Amortization of net actuarial (gain) loss | 47 | 7 | — | 4 | 1 | (1) |
| Amortization of transition obligation | — | (1) | (6) | 8 | 8 | 8 |
| Amortization of prior service cost[1] | (3) | (3) | (3) | (1) | (1) | (1) |
| Settlements, curtailment, and special termination benefits | (4) | 11 | — | — | (6) | — |
| Net benefit cost (income) | $ 5 | $ (43) | $(101) | $ 35 | $29 | $37 |

(1) As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit costs of our pension and other postretirement plans for 2004, 2003 and 2002:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | | (Percent) | | | (Percent) | |
| Assumptions related to benefit obligations at September 30: | | | | | | |
| Discount rate | 5.75 | 6.00 | | 5.75 | 6.00 | |
| Rate of compensation increase | 4.00 | 4.00 | | | | |
| Assumptions related to benefit costs for the year ended December 31: | | | | | | |
| Discount rate | 6.00 | 6.75 | 7.25 | 6.00 | 6.75 | 7.25 |
| Expected return on plan assets(1) | 8.50 | 8.80 | 8.80 | 7.50 | 7.50 | 7.50 |
| Rate of compensation increase | 4.00 | 4.00 | 4.00 | | | |

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 26 percent to 27 percent on other postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio. For 2005, the assumed expected return on assets for pension benefits will be reduced to 8 percent.

Actuarial estimates for our other postretirement benefit plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

| | 2004 | 2003 |
|---|---|---|
| | (In millions) | |
| One percentage point increase: | | |
| Aggregate of service cost and interest cost | $ 1 | $ 1 |
| Accumulated postretirement benefit obligation | 19 | 21 |
| One percentage point decrease: | | |
| Aggregate of service cost and interest cost | $ (1) | $ (1) |
| Accumulated postretirement benefit obligation | (18) | (19) |

*Plan Assets*

The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

| | Pension Plans | | | Other Postretirement Plans | | |
|---|---|---|---|---|---|---|
| Asset Category | Target | Actual 2004 | Actual 2003 | Target | Actual 2004 | Actual 2003 |
| | | (Percent) | | | (Percent) | |
| Equity securities(1) | 60 | 62 | 70 | 65 | 60 | 29 |
| Debt securities | 40 | 37 | 29 | 35 | 33 | 60 |
| Other | — | 1 | 1 | — | 7 | 11 |
| Total | 100 | 100 | 100 | 100 | 100 | 100 |

(1) Actuals for our pension plans include $42 million (1.8 percent of total assets) and $33 million (1.5 percent of total assets) of our common stock at September 30, 2004 and September 30, 2003.

The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

In 2003, we modified our target asset allocations for our other postretirement benefit plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2004 were close to our targets. During 2004, we modified our target and actual asset allocations for our pension plans to reduce our equity allocation to 60 percent of total plan assets. Correspondingly, our 2005 assumption related to the expected return on plan assets were reduced from 8.5 percent to 8.0 percent to reflect this change.

## 19. Capital Stock

*Common Stock*

In 2003 and 2004, we issued 26.4 million shares to satisfy our obligations under the Western Energy Settlement (See Note 17). In 2003, we also issued 15 million shares as part of an offer to exchange our equity security units for common stock (see Note 15).

*Dividend*

For the year ended December 31, 2004, we paid dividends of $101 million to common stockholders. On February 18, 2005, we declared quarterly dividends of $0.04 per share on our common stock, payable on April 4, 2005 to the shareholders of record on March 4, 2005. The dividends on our common stock were treated as a reduction of paid-in-capital since we currently have an accumulated deficit.

El Paso Tennessee Pipeline Co., our subsidiary, pays dividends of approximately $6 million each quarter on its Series A cumulative preferred stock, which is 8.25 percent per annum (2.0625 percent per quarter).

## 20. Stock-Based Compensation

We grant stock awards under various stock option plans. We account for our stock option plans using Accounting Principles Board Opinion No. 25 and its related interpretations. Under our employee plans, we may issue incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, stock appreciation rights, phantom stock options, and performance units. Under our non-employee director plan, we may issue deferred shares of common stock. We have reserved approximately 68 million shares of common stock for existing and future stock awards, including deferred shares. As of December 31, 2004, approximately 28 million shares remained unissued.

*Non-qualified Stock Options*

We granted non-qualified stock options to our employees in 2004, 2003 and 2002. Our stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. Prior to 2004, we also granted options to non-employee members of the Board of Directors at fair market value on the grant date that were exercisable immediately. A summary of our stock option transactions, stock options outstanding and stock options exercisable as of December 31 is presented below:

| | Stock Options | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | 2003 | | 2002 | |
| | # Shares of Underlying Options | Weighted Average Exercise Price | # Shares of Underlying Options | Weighted Average Exercise Price | # Shares of Underlying Options | Weighted Average Exercise Price |
| Outstanding at beginning of year | 36,245,014 | $47.90 | 43,208,374 | $49.16 | 44,822,146 | $50.02 |
| Granted | 4,842,453 | $ 7.16 | 1,180,041 | $ 7.29 | 3,435,138 | $35.41 |
| Exercised | (3,193) | $ 7.64 | — | — | (310,611) | $22.44 |
| Converted[1] | (11,333) | $42.99 | (871,250) | $42.00 | — | — |
| Forfeited or canceled | (7,149,363) | $44.75 | (7,272,151) | $49.53 | (4,738,299) | $51.83 |
| Outstanding at end of year | 33,923,578 | $42.73 | 36,245,014 | $47.90 | 43,208,374 | $49.18 |
| Exercisable at end of year | 28,455,056 | $49.45 | 28,703,151 | $46.04 | 25,493,152 | $43.00 |
| Weighted average fair value of options granted during the year | | $ 2.69 | | $ 3.21 | | $14.23 |

(1) Includes the conversion of stock options into common stock and cash at no cost to employees based upon achievement of certain performance targets and lapse of time. These options had an original stated exercise price of approximately $43 per share and $42 per share in 2004 and 2003.

The following table summarizes the range of exercise prices and the weighted-average remaining contractual life of options outstanding and the range of exercise prices for the options exercisable at December 31, 2004.

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number Outstanding | Weighted Average Remaining Years of Contractual Life | Weighted Average Exercise Price | Number Exercisable | Weighted Average Exercise Price |
| $ 0.00 - $21.39 | 7,537,238 | 7.1 | $ 9.25 | 2,154,339 | $14.35 |
| $21.40 - $42.89 | 8,761,610 | 2.9 | $37.53 | 8,707,300 | $37.52 |
| $42.90 - $64.29 | 12,302,057 | 3.6 | $54.88 | 12,272,411 | $54.91 |
| $64.30 - $70.63 | 5,322,673 | 4.7 | $70.59 | 5,321,006 | $70.59 |
| | 33,923,578 | 4.4 | $42.73 | 28,455,056 | $49.45 |

The fair value of each stock option granted used to complete pro forma net income disclosures (see Note 1) is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

| Assumption: | 2004 | 2003 | 2002 |
|---|---|---|---|
| Expected Term in Years | 5.35 | 6.19 | 6.95 |
| Expected Volatility | 45% | 52% | 43% |
| Expected Dividends | 2.1% | 2.2% | 1.8% |
| Risk-Free Interest Rate | 3.7% | 3.4% | 3.2% |

*Restricted Stock*

Under our stock-based compensation plans, a limited number of shares of restricted common stock may be granted to our officers and employees. These shares carry voting and dividend rights; however, sale or transfer of the shares is restricted. These restricted stock awards vest over a specific period of time and/or if we achieve established performance targets. Restricted stock awards representing 3.1 million, 0.4 million, and 1.4 million shares were granted during 2004, 2003 and 2002 with a weighted-average grant date fair value of $8.63, $7.46 and $38.45 per share. At December 31, 2004, 3.9 million shares of restricted stock were outstanding. The value of restricted shares subject to performance vesting is determined based on the fair market value on the date performance targets are achieved, and this value is charged to compensation expense ratably over the required service or restriction period. The value of time vested restricted shares is determined at their issuance date and this cost is amortized to compensation expense over the vesting period. For 2004, 2003 and 2002, these charges totaled $23 million, $60 million and $73 million. We have $20 million on our balance sheet as of December 31, 2004 related to unamortized compensation that will be charged to expense over the vesting period of the restricted stock.

*Performance Units*

In the past, we awarded eligible officers performance units that were payable in cash or stock at the end of the vesting period. The final value of the performance units varied according to the plan under which they were granted, but was usually based on our common stock price at the end of the vesting period or total shareholder return during the vesting period relative to our peer group. The value of the performance units was charged ratably to compensation expense over the vesting period with periodic adjustments to account for the fluctuation in the market price of our stock or changes in expected total shareholder return. We recorded a credit to compensation expense in 2002 of $11 million upon the reduction of our performance unit liability by $21 million due to a reduction in our expected total shareholder return. In July 2003, all outstanding performance units vested at the "Below Threshold" level and the Compensation Committee of our Board of Directors determined that there would be no payout for the performance units. Accordingly, we reversed the remaining liability for these units and recorded income of $16 million.

*Employee Stock Purchase Program*

In October 1999, we implemented an employee stock purchase plan under Section 423 of the Internal Revenue Code. The plan allowed participating employees the right to purchase our common stock on a quarterly basis at 85 percent of the lower of the market price at the beginning or at the end of each calendar quarter. Five million shares of common stock are authorized for issuance under this plan. For the year ended December 31, 2002, we sold 1.4 million shares of our common stock to our employees. Effective January 1, 2003, we suspended our employee stock purchase program.

**21. Business Segment Information**

During 2004, we reorganized our business structure into two primary business lines, regulated and non-regulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established individual Power and Marketing and Trading segments. All periods presented reflect this change in segments. Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Marketing and Trading, Power, and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions as well as a telecommunications business, and various other contracts and assets, all of which are immaterial. These other assets and contracts include financial services, LNG and related items.

During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations. Our operating results for all periods presented reflect these changes.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the U.S. We conduct our activities primarily through eight wholly owned and four partially owned interstate transmission systems along with five underground natural gas storage entities and an LNG terminalling facility.

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 the United States and Brazil. In the U.S., Production has onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico.

Our Marketing and Trading segment's operations focus on the marketing of our natural gas and oil production and the management of our remaining trading portfolio.

Our Power segment owns and has interests in domestic and international power assets. As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also had domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses. Our ongoing focus within the power segment will be to maximize the value of our assets in Brazil.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2004, 2003 and 2002.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

| | 2004 | 2003 (Restated) | 2002 (Restated) |
|---|---|---|---|
| | | (In millions) | |
| Total EBIT | $ 855 | $ 769 | $ (427) |
| Interest and debt expense | (1,607) | (1,791) | (1,297) |
| Distributions on preferred interests of consolidated subsidiaries | (25) | (52) | (159) |
| Income taxes | (25) | 469 | 641 |
| Loss from continuing operations | $ (802) | $ (605) | $(1,242) |

The following tables reflect our segment results as of and for each of the three years ended December 31:

| | Regulated | Non-regulated | | | | | |
|---|---|---|---|---|---|---|---|
| | Segments As of or for the Year Ended December 31, 2004 | | | | | | |
| | Pipelines | Production | Marketing and Trading | Power | Field Services | Corporate[(1)] | Total |
| | (In millions) | | | | | | |
| Revenue from external customers | | | | | | | |
| Domestic | $ 2,554 | $ 535[(2)] | $ 697 | $ 241 | $1,203 | $ 132 | $ 5,362 |
| Foreign | 9 | 26[(2)] | 2 | 460 | — | 15 | 512 |
| Intersegment revenue | 88 | 1,174[(2)] | (1,207) | 94 | 159 | (308) | — |
| Operation and maintenance | 777 | 365 | 53 | 374 | 102 | 201 | 1,872 |
| Depreciation, depletion, and amortization | 410 | 548 | 13 | 54 | 12 | 51 | 1,088 |
| (Gain) loss on long-lived assets | (1) | 8 | — | 583 | 508 | (6) | 1,092 |
| Operating income (loss) | $ 1,129 | $ 726 | $ (562) | $ (408) | $ (465) | $ (214) | $ 206 |
| Earnings from unconsolidated affiliates | 173 | 4 | — | (236) | 618 | — | 559 |
| Other income | 33 | 4 | 15 | 84 | 2 | 51 | 189 |
| Other expense | (4) | — | — | (9) | (35) | (51) | (99) |
| EBIT | $ 1,331 | $ 734 | $ (547) | $ (569) | $ 120 | $ (214) | $ 855 |
| Discontinued operations, net of income taxes | $ — | $ (76) | $ — | $ — | $ — | $ (70) | $ (146) |
| Assets of continuing operations[(3)] | | | | | | | |
| Domestic | 15,930 | 3,714 | 2,372 | 982 | 686 | 4,424 | 28,108 |
| Foreign[(4)] | 58 | 366 | 32 | 2,617 | — | 96 | 3,169 |
| Capital expenditures and investments in and advances to unconsolidated affiliates, net[(5)] | 1,047 | 728 | — | 29 | (5) | 10 | 1,809 |
| Total investments in unconsolidated affiliates | 1,032 | 6 | — | 1,262 | 308 | 6 | 2,614 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $308 million and an operation and maintenance expense elimination of $25 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Excludes assets of discontinued operations of $106 million (see Note 3).

(4) Of total foreign assets, approximately $1.3 billion relates to property, plant and equipment and approximately $1.5 billion relates to investments in and advances to unconsolidated affiliates.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

| | Regulated | Non-regulated | | | | | |
|---|---|---|---|---|---|---|---|
| | Pipelines | Production (Restated) | Marketing and Trading | Power | Field Services | Corporate[1] | Total (Restated) |
| | **Segments As of or for the Year Ended December 31, 2003 (In millions)** | | | | | | |
| Revenue from external customers | | | | | | | |
| Domestic | $ 2,527 | $ 201[2] | $ 1,430 | $ 515 | $1,153 | $ 113 | $ 5,939 |
| Foreign | 2 | — | — | 516 | 2 | 13 | 533 |
| Intersegment revenue | 118 | 1,940[2] | (2,065) | 145 | 374 | (316) | 196[3] |
| Operation and maintenance | 720 | 342 | 183 | 562 | 110 | 93 | 2,010 |
| Depreciation, depletion, and amortization | 386 | 576 | 25 | 91 | 31 | 67 | 1,176 |
| Western Energy Settlement | 127 | — | (25) | — | — | 2 | 104 |
| (Gain) loss on long-lived assets | (10) | 5 | (3) | 185 | 173 | 510 | 860 |
| Operating income (loss) | $ 1,063 | $1,073 | $ (819) | $ (13) | $ (193) | $ (706) | $ 405 |
| Earnings (losses) from unconsolidated affiliates | 119 | 13 | — | (91) | 329 | (7) | 363 |
| Other income | 57 | 5 | 12 | 90 | — | 39 | 203 |
| Other expense | (5) | — | (2) | (14) | (3) | (178) | (202) |
| EBIT | $ 1,234 | $1,091 | $ (809) | $ (28) | $ 133 | $ (852) | $ 769 |
| Discontinued operations, net of income taxes | $ — | $ (11) | $ — | $ — | $ — | $(1,303) | $(1,314) |
| Cumulative effect of accounting changes, net of income taxes | (4) | (3) | — | — | (2) | — | (9) |
| Assets of continuing operations[4] | | | | | | | |
| Domestic | 15,659 | 3,459 | 2,661 | 3,897 | 1,990 | 3,889 | 31,555 |
| Foreign | 27 | 308 | 5 | 3,102 | — | 141 | 3,583 |
| Capital expenditures and investments in and advances to unconsolidated affiliates, net[5] | 837 | 1,300 | (1) | 1,083 | (15) | 89 | 3,293 |
| Total investments in unconsolidated affiliates | 1,018 | 79 | — | 1,652 | 655 | 5 | 3,409 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $316 million and an operation and maintenance expense elimination of $59 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $1.8 billion (see Note 3).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital. Our Power Segment Includes $1 billion to acquire remaining interest in Chaparral and Gemstone (see Note 2).

| | Regulated | Non-regulated | | | | | |
|---|---|---|---|---|---|---|---|
| | Pipelines (Restated) | Production | Marketing and Trading | Power | Field Services | Corporate[1] | Total (Restated) |
| | Segments As of or for the Year Ended December 31, 2002 (In millions) | | | | | | |
| Revenue from external customers | | | | | | | |
| Domestic | $ 2,389 | $ 308[2] | $ 926 | $1,268 | $1,145 | $ 97 | $ 6,133 |
| Foreign | 3 | — | (41) | 361 | 3 | 79 | 405 |
| Intersegment revenue | 218 | 1,623[2] | (2,209) | 43 | 881 | (213) | 343 |
| Operation and maintenance | 752 | 368 | 173 | 520 | 179 | 99 | 2,091 |
| Depreciation, depletion, and amortization | 374 | 601 | 11 | 45 | 56 | 72 | 1,159 |
| Western Energy Settlement | 412 | — | 487 | — | — | — | 899 |
| (Gain) loss on long-lived assets | (13) | (1) | — | 160 | (179) | 214 | 181 |
| Operating income (loss) | $ 788 | $ 803 | $(1,993) | $ 352 | $ 273 | $ (394) | $ (171) |
| Earnings (losses) from unconsolidated affiliates | 10 | 7 | — | (256) | 18 | 7 | (214) |
| Other income | 34 | 1 | 19 | 40 | 3 | 100 | 197 |
| Other expense | (4) | (3) | (3) | (124) | (5) | (100) | (239) |
| EBIT | $ 828 | $ 808 | $(1,977) | $ 12 | $ 289 | $ (387) | $ (427) |
| Discontinued operations, net of income taxes | $ — | $ (68) | $ — | $ — | $ — | $ (357) | $ (425) |
| Cumulative effect of accounting changes, net of income taxes | — | — | (222) | 14 | — | — | (208) |
| Assets of continuing operations[4] | | | | | | | |
| Domestic | 14,727 | 3,495 | 5,568 | 2,759 | 2,714 | 4,265 | 33, 528 |
| Foreign | 59 | 208 | 844 | 2,485 | 14 | 277 | 3,887 |
| Capital expenditures and investments in and advances to unconsolidated affiliates, net[5] | 1,075 | 2,114 | 47 | 91 | 187 | 48 | 3,562 |
| Total investments in unconsolidated affiliates | 992 | 87 | — | 2,725 | 922 | 23 | 4,749 |

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $213 million and an operation and maintenance expense elimination of $41 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $4.5 billion (see Note 3).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

## 22. Investments in, Earnings from and Transactions with Unconsolidated Affiliates

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 was less than our equity in the net assets of these investments by $265 million and $136 million as of December 31, 2004 and 2003. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the year ended December 31:

| | Net Ownership Interest | | Investment | | Earnings from Unconsolidated Affiliates | | |
|---|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 (Restated) | 2004 | 2003 | 2002 (Restated) |
| | (Percent) | | (In millions) | | (In millions) | | |
| Domestic: | | | | | | | |
| Citrus | 50 | 50 | $ 589 | $ 593 | $ 65 | $ 43 | $ 43 |
| Enterprise Products Partners(1) | —(1) | — | 257 | — | 6 | — | — |
| GulfTerra Energy Partners(1) | — | —(1) | — | 599 | 601 | 419 | 69 |
| Midland Cogeneration Venture(2) | 44 | 44 | 191 | 348 | (171) | 29 | 28 |
| Great Lakes Gas Transmission(3) | 50 | 50 | 316 | 325 | 65 | 57 | 63 |
| Javelina | 40 | 40 | 45 | 40 | 15 | (2) | — |
| Milford(4) | — | — | — | — | (1) | (88) | (22) |
| Bastrop Company(5) | — | 50 | — | 73 | (1) | (48) | (5) |
| Mobile Bay Processing(5) | — | 42 | — | 11 | — | (48) | (2) |
| Blue Lake Gas Storage(6) | — | 75 | — | 30 | — | 9 | 8 |
| Chaparral Investors (Electron)(7) | — | — | — | — | — | (207) | (62) |
| Linden Venture L.P. (East Coast Power) | — | — | — | — | — | 65 | — |
| Dauphin Island(5) | — | 15 | — | — | — | (40) | (1) |
| Alliance Pipeline Limited Partnership(4) | — | — | — | — | — | — | 25 |
| CE Generation(4) | — | — | — | — | — | — | (52) |
| Aux Sable NGL | — | — | — | — | — | — | (50) |
| Other Domestic Investments | various | various | 136 | 137 | 26 | 26 | 29 |
| Total domestic | | | 1,534 | 2,156 | 605 | 215 | 71 |
| Foreign: | | | | | | | |
| Korea Independent Energy Corporation | 50 | 50 | 176 | 145 | 22 | 29 | 24 |
| Araucaria Power(8) | 60 | 60 | 186 | 181 | — | — | — |
| EGE Itabo | 25 | 25 | 88 | 87 | 1 | 1 | (2) |
| Bolivia to Brazil Pipeline | 8 | 8 | 86 | 66 | 24 | 17 | 2 |
| EGE Fortuna | 25 | 25 | 65 | 59 | 6 | 3 | 5 |
| Meizhou Wan Generating | 26 | 25 | 52 | 63 | (14) | 8 | (20) |
| Enfield Power(9) | 25 | 25 | 51 | 55 | 1 | 3 | (3) |
| Aguaytia Energy | 24 | 24 | 39 | 51 | (5) | 4 | 3 |
| San Fernando Pipeline | 50 | 50 | 46 | 41 | 13 | 5 | — |
| Habibullah Power(10) | 50 | 50 | 20 | 48 | (46) | (3) | 10 |
| Gasoducto del Pacifico Pipeline | 22 | 22 | 33 | 37 | 4 | 3 | (2) |
| Samalayuca(11) | 50 | 50 | 35 | 24 | 5 | 3 | 21 |
| Saba Power Company | 94 | 94 | 7 | 59 | (51) | 4 | 7 |
| Australian Pipelines(5) | — | 33 | — | 38 | 4 | (3) | (142) |
| UnoPaso(6) | — | 50 | — | 73 | 4 | 14 | 6 |
| Diamond Power (Gemstone)(7) | — | — | — | — | — | 17 | 109 |
| CAPSA(4) | — | — | — | — | — | 24 | (262) |
| PPN(12) | 26 | 26 | — | — | — | — | (50) |
| Agua del Cajon(4) | — | — | — | — | — | — | (24) |
| Other Foreign Investments(10) | various | various | 196 | 226 | (14) | 19 | 33 |
| Total foreign | | | 1,080 | 1,253 | (46) | 148 | (285) |
| Total investments in unconsolidated affiliates | | | $2,614 | $ 3,409 | | | |
| Total earnings (losses) from unconsolidated affiliates | | | | | $ 559 | $ 363 | $ (214) |

(1) As of December 31, 2003, we owned an effective 50 percent interest in the one percent general partner of GulfTerra, approximately 17.8 percent of the partnership's common units and all of the outstanding Series C units. During 2004 we sold our remaining interest in GulfTerra to Enterprise for cash and equity interests in Enterprise and recognized a $507 million gain. As of December 31, 2004, our ownership consisted of a 9.9 percent interest in the two percent general partner of Enterprise and approximately 3.7 percent of Enterprise's common units. In January 2005, we sold all of these remaining interests to Enterprise. For a further discussion of our interests in GulfTerra and Enterprise, see page 165.

(2) Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.

(3) Includes a 47 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 3 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.

(4) In 2003 we completed the sale or transfer of our interest in this investment.

(5) In 2004 we completed the sale of our interest in this investment.

(6) Consolidated in 2004.

(7) This investment was consolidated in 2003.

(8) Our investment in Araucaria Power was included in Diamond Power (Gemstone) prior to 2003.

(9) We have signed an agreement to sell our interest in the project and expect to close the transaction in the first half of 2005.

(10) As of December 31, 2004 and 2003, we also had outstanding advances of $64 million and $90 million related to our investment in Habibullah Power. We also had other outstanding advances of $318 million and $327 million related to our other foreign investments as of December 31, 2004 and 2003, of which $307 million and $290 million are related to our investment in Porto Velho.

(11) Consists of investments in a power facility and pipeline. In 2002, we sold our investment in the power facility.

(12) Impaired in 2002 due to our inability to recover our investment. Earnings generated in 2003 and 2004 did not improve the recoverability of this investment. We sold our interest in March 2005.

Our impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates during 2004, 2003 and 2002 consisted of the following:

| Investment | Pre-tax Gain (Loss) (In millions) | Cause of Impairments or Gain (Loss) |
|---|---|---|
| *2004* | | |
| Gain on sale of interests in GulfTerra[1] | $ 507 | Sale of investment |
| Asian power investments[2] | (182) | Anticipated sales of investments |
| Midland Cogeneration Venture | (161) | Decline in investment's fair value based on increased fuel costs |
| Power investments held for sale | (49) | Anticipated sales of investments |
| Net gain on domestic power investment sales[3] | 7 | Sales of power investments |
| Other | 7 | |
| Total | $ 129 | |
| *2003* | | |
| Gain on sale of interests in GulfTerra[4] | $ 266 | Sale of various investment interests in GulfTerra |
| Chaparral Investors (Electron) | (207) | Decline in the investment's fair value based on developments in our power business and the power industry |
| Milford power facility[5] | (88) | Transfer of ownership to lenders |
| Dauphin Island Gathering/Mobile Bay Processing | (86) | Decline in the investments' fair value based on the devaluation of the underlying assets |
| Bastrop Company | (43) | Decision to sell investment |
| Linden Venture, L.P. (East Coast Power) | (22) | Sale of investment in East Coast Power |
| Other investments | 4 | |
| Total | $(176) | |
| *2002 (Restated)* | | |
| CAPSA/CAPEX | $(262) | Weak economic conditions in Argentina |
| EPIC Australia | (141) | Regulatory difficulties and the decision to discontinue further capital investment |
| CE Generation | (74) | Sale of investment |
| Aux Sable NGL | (47) | Sale of investment |
| Agua del Cajon | (24) | Weak economic conditions in Argentina |
| PPN | (41) | Loss of economic fuel supply and payment default |
| Meizhou Wan Generating | (7) | Weak economic conditions in China |
| Other investments | (16) | |
| Total | $(612) | |

(1) In September 2004, in connection with the closing of the merger between GulfTerra and Enterprise, we sold to affiliates of Enterprise substantially all of our interests in GulfTerra. See further discussion of GulfTerra beginning on page 165.

(2) Includes impairments of our investments in Korea Independent Energy Corporation, Meizhou Wan Generating, Habibullah Power, Saba Power Company and several other foreign power investments.

(3) Includes a loss on the sale of Bastrop Company and gains on the sale of several other domestic investments.

(4) In 2003, we sold 50 percent of the equity of our consolidated subsidiary that holds our 1 percent general partner interest. This was recorded as minority interest in our balance sheet.

(5) In December 2003, we transferred our ownership interest in Milford to its lenders in order to terminate all of our obligations associated with Milford.

Below is summarized financial information of our proportionate share of unconsolidated affiliates. This information 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. We received distributions and dividends of $358 million and $398 million in 2004 and 2003, which includes $23 million and $53 million of returns of capital, from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $15 million, $119 million and $26 million in 2004, 2003 and 2002 and total assets of $734 million and $1.1 billion as of December 31, 2004 and 2003.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | | (Unaudited) (In millions) | |
| Operating results data: | | | |
| Operating revenues | $2,211 | $3,360 | $2,486 |
| Operating expenses | 1,485 | 2,309 | 1,632 |
| Income from continuing operations | 388 | 519 | 422 |
| Net income | 388 | 520 | 445 |

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| | (Unaudited) (In millions) | |
| Financial position data: | | |
| Current assets | $1,270 | $ 1,024 |
| Non-current assets | 5,243 | 8,001 |
| Short-term debt | 250 | 1,169 |
| Other current liabilities | 488 | 645 |
| Long-term debt | 2,044 | 1,892 |
| Other non-current liabilities | 779 | 1,703 |
| Minority interest | 73 | 71 |
| Equity in net assets | 2,879 | 3,545 |

Below is summarized financial information of GulfTerra (in millions):

| | Nine months ended September 30, 2004 | Year Ended December 31, 2003 | Year ended December 31, 2002 |
|---|---|---|---|
| | (Unaudited) | | |
| Operating results data: | | | |
| Net sales or gross revenues | $677 | $871 | $457 |
| Operating expenses | 432 | 557 | 297 |
| Income from continuing operations | 155 | 161 | 93 |
| Net income | 155 | 163 | 98 |

| | As of September 30, 2004 | As of December 31, 2003 |
|---|---|---|
| | (Unaudited) | |
| Financial position data: | | |
| Current assets | $ 230 | $ 209 |
| Noncurrent assets | 3,167 | 3,113 |
| Current liabilities | 200 | 209 |
| Noncurrent liabilities | 1,921 | 1,860 |
| Equity in net assets | 1,276 | 1,253 |

The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| Operating revenue | $218 | $216 | $ 65 |
| Other revenue — management fees | 4 | 13 | 192 |
| Cost of sales | 102 | 106 | 178 |
| Reimbursement for operating expenses | 97 | 140 | 186 |
| Other income | 8 | 10 | 18 |
| Interest income | 8 | 11 | 30 |
| Interest expense | — | 2 | 42 |

*Chaparral and Gemstone*

As of December 31, 2002, we held equity investments in Chaparral and Gemstone. During 2003, we acquired the remaining third party equity interests and all of the voting rights in both of these entities. As discussed in Note 2, we consolidated Chaparral effective January 1, 2003 and Gemstone effective April 1, 2003.

*GulfTerra*

Prior to the sale of our interests in GulfTerra on September 30, 2004, our Field Services segment managed GulfTerra's daily operations and performed all of GulfTerra's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributed to our income through our general partner interest and our ownership of common and preference units. We did not have any loans to or from GulfTerra.

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge to form the second largest publicly traded energy partnership in the U.S. On July 29, 2004, GulfTerra's unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004. In January 2005, we sold our remaining 9.9 percent interest in the two percent general partner of Enterprise and approximately 13.5 million common units in Enterprise for $425 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million.

In the December 2003 sales transactions, specific evaluation procedures were instituted to ensure that they were in the best interests of us and the partnership and were based on fair values. These procedures required our Board of Directors to evaluate and approve, as appropriate, each transaction with GulfTerra. In addition, a special committee comprised of the GulfTerra general partner's independent directors evaluated the transactions on GulfTerra's behalf. Both boards engaged independent financial advisors to assist with the evaluation and to opine on its fairness.

Below is a detail of the gains or losses recognized in earnings from unconsolidated affiliates on transactions related to GulfTerra/Enterprise and other significant transactions during 2002, 2003, and 2004:

| Transaction | Proceeds | Realized Gain/(Loss) |
|---|---|---|
| | (In millions) | |
| 2002 | | |
| Sold San Juan Basin gathering, treating, and processing assets and Texas & New Mexico midstream assets to GulfTerra[1] | $1,501 | $210 |
| 2003 | | |
| Sold 9.9% of our 1% general partner interest in GulfTerra to Goldman Sachs | 88 | — |
| Repurchased the 9.9% interest from Goldman Sachs[2] | (116) | (28) |
| Redeemed series B preference units | 156 | (11) |
| Released from obligation in 2021 to purchase Chaco facility[3] | (10) | 67 |
| Sold 50% general partnership interest in GulfTerra to Enterprise[4] | 425 | 297 |
| Other GulfTerra common unit sales | 23 | 8 |
| 2004 | | |
| Sold our interest in the general partner of GulfTerra, 2.9 million common units and 10.9 million series C units in GulfTerra to Enterprise[5][6] | 951 | 507 |

(1) We received $955 million of cash, Series C units in GulfTerra with a value of $356 million, and an interest in a production field with a value of $190 million. We recorded an additional $74 million liability and related loss in 2003 for future pipeline integrity costs related to the transmission assets, for which we agreed to reimburse GulfTerra through 2006.

(2) We paid $92 million in cash and transferred GulfTerra common units with a book value of $19 million to Goldman Sachs in December 2003. We also paid $5 million of miscellaneous expenses related to the repurchase.

(3) We satisfied our obligation to GulfTerra through the transfer of communications assets with a book value of $10 million.

(4) The cash flows were reflected in our 2003 cash flow statement as an investing activity and $84 million of the proceeds were reflected as minority interest on our balance sheet. We also agreed to pay $45 million to Enterprise through 2006.

(5) We received $870 million in cash and a 9.9 percent interest in the general partner of the combined organization, Enterprise Products GP, with a fair value of $82 million. We also exchanged our remaining GulfTerra common units for 13.5 million Enterprise common units.

(6) As a result of the Enterprise transaction, we also recorded a $480 million impairment of the goodwill in loss on long-lived assets on our income statement associated with our Field Services segment. In addition, we sold South Texas assets to Enterprise for total proceeds of $156 million and a loss of $11 million included in our loss on long-lived assets.

Prior to the sale of our interests in GulfTerra to Enterprise in September 2004, a subsidiary in our Field Services segment served as the general partner of GulfTerra, a publicly traded master limited partnership. We had the following interests in GulfTerra (Enterprise effective September 30, 2004) as of December 31:

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Book Value (In millions) | Ownership (Percent) | Book Value (In millions) | Ownership (Percent) |
| One Percent General Partner[1] | $ 82 | 9.9 | $194 | 100.0 |
| Common Units | 175 | 3.7 | 251 | 17.8 |
| Series C Units | — | — | 335 | 100.0 |
| Total | $257 | | $780 | |

(1) We had $181 million of indefinite-lived intangible assets related to our general partner interest as of December 31, 2003. We also have $96 million recorded as minority interest related to the effective general partnership interest acquired by Enterprise in December 2003. This reduced our effective ownership interest in the general partner to 50 percent. Both of these were disposed of in the Enterprise sales described above.

During each of the three years ended December 31, 2004, we conducted the following transactions with GulfTerra:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In millions) | |
| Revenues received from GulfTerra | | | |
| Field Services | $ 2 | $ 5 | $ 1 |
| Marketing and Trading | 26 | 28 | 19 |
| Production | — | — | 3 |
| | $ 28 | $ 33 | $ 23 |
| Expenses paid to GulfTerra | | | |
| Field Services | $ 84 | $ 75 | $ 97 |
| Marketing and Trading | 20 | 30 | 93 |
| Production | 9 | 9 | 9 |
| | $113 | $114 | $199 |
| Reimbursements received from GulfTerra | | | |
| Field Services | $ 71 | $ 91 | $ 60 |

*Contingent Matters that Could Impact Our Investments*

*Economic Conditions in the Dominican Republic.* We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $103 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso. As a consequence of economic conditions described above, combined with the high prices on imported fuels and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales which may affect CEPP's ability to operate. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments may occur.

*Berkshire Power Project.* We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. We supply natural gas to Berkshire under a fuel management agreement. Berkshire has the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million, if Berkshire does not have available cash to meet its debt service requirements. Berkshire has delayed a total of $46 million of its fuel payments, including $8 million of interest, under this agreement as of December 31, 2004. During 2002, Berkshire's lenders asserted that Berkshire was in default on its loan agreement, and these issues remain unresolved. Based on the uncertainty surrounding these negotiations and Berkshire's inability to generate adequate future cash flow, we recorded losses of $10 million and $28 million in 2004 and 2003 associated with the amounts due to us under the fuel supply agreement.

For contingent matters that could impact our investments in Brazil, see Note 17.

For a discussion of non-recourse project financing, see Note 15.

*Duke Litigation.* Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus) has filed suit against Duke Energy LNG Sales, Inc (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. Duke has filed in federal court an amended counter claim joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke's motion, which is currently pending before the court. An unfavorable outcome on this matter could impact the value of our investment in Citrus.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
El Paso Corporation:

We have completed an integrated audit of El Paso Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

### Consolidated Financial Statements and Financial Statement Schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the second and fourth paragraphs of Note 1, the 2002 and 2003 consolidated financial statements have been restated.

As discussed in the notes to the consolidated financial statements, the Company adopted FASB Financial Interpretation No. 46, *Consolidation of Variable Interest Entities* on January 1, 2004; FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* on July 1, 2004; Statement of Financial Accounting Standards (SFAS) No. 150*, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; SFAS No. 143, *Accounting for Asset Retirement Obligations* and SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* on January 1, 2003; SFAS No. 141, *Business Combinations*, SFAS No. 142, *Goodwill and Other Intangible Assets* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions; applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* on July 1, 2002 and EITF Issue No. 02-03, *Accounting for the Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2*, on October 1, 2002.

### Internal Control Over Financial Reporting

Also, we have audited management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, which includes consideration of the matter referred to in the fourth paragraph of Note 1, that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, because the Company did not maintain effective controls over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. Management's assessment was based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management's assessment. At December 31, 2004, the Company did not maintain effective control over (1) access to financial applications programs and data, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. A specific description of these control deficiencies which management concluded are material weaknesses, that existed at December 31, 2004, is discussed below.

*Access to Financial Application Programs and Data.* At December 31, 2004, the Company did not maintain effective controls over access to financial application programs and data at each of its operating segments. Internal control deficiencies were identified with respect to inadequate design of and compliance with security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and lack of independent monitoring of access to various systems by information technology staff, as well as certain users with accounting and reporting responsibilities who also have security administrator access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of the Company's financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, price risk management assets and liabilities, and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

*Account Reconciliations.* At December 31, 2004, the Company did not maintain effective controls over the preparation and review of account reconciliations related to accounts such as prepaid insurance, accounts receivable, other assets and taxes other than income taxes. Specifically, instances were identified in the Power and Marketing and Trading businesses where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. Instances were also noted where accounts were not being reconciled and reviewed by individuals with adequate accounting experience and training. These control deficiencies resulted in adjustments impacting the fourth quarter of 2004 financial statements. Furthermore, these control deficiencies could result in a misstatement of the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, these control deficiencies constitute a material weakness.

*Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities.* At December 31, 2004, the Company did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. Control deficiencies were identified related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment of long-lived assets, and accounting for divestiture of assets. These control deficiencies resulted in the restatement of the 2002 and, as described in the fourth paragraph of Note 1, the 2003 financial statements and related 2003 fourth quarter information as reflected in this annual report as well as adjustments to the aforementioned accounts impacting the financial statements for the fourth quarter of 2004. Furthermore, these control deficiencies could result in a material misstatement in the aforementioned accounts that would result in a misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly these control deficiencies constitute a material weakness.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

In our opinion, management's assessment that El Paso Corporation did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control — Integrated Framework* issued by COSO. Also, in our opinion, because of the effects of the material weaknesses described above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by COSO.

PricewaterhouseCoopers LLP
Houston Texas
March 25, 2004 except for the
fourth paragraph of Note 1
as to which the date
is April 7, 2005

**Supplemental Selected Quarterly Financial Information (Unaudited)**

Financial information by quarter, is summarized below.

| | Quarters Ended | | | | |
|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | Total |
| | (In millions, except per common share amounts) | | | | |
| 2004 | | | | | |
| Operating revenues | $1,557 | $ 1,524 | $1,429 | $1,364 | $ 5,874 |
| Loss on long-lived assets | 222 | 17 | 582 | 271 | 1,092 |
| Operating income (loss) | 205 | 370 | (355) | (14) | 206 |
| Income (loss) from continuing operations | $ (97) | $ 45 | $ (202) | $ (548) | $ (802) |
| Discontinued operations, net of income taxes[1] | (109) | (29) | (12) | 4 | (146) |
| Net income (loss) | $ (206) | $ 16 | $ (214) | $ (544) | $ (948) |
| Basic and diluted earnings per common share | | | | | |
| Income (loss) from continuing operations | $(0.15) | $ 0.07 | $(0.31) | $(0.86) | $ (1.25) |
| Discontinued operations, net of income taxes | (0.17) | (0.04) | (0.02) | 0.01 | (0.23) |
| Net income (loss) | $(0.32) | $ 0.03 | $(0.33) | $(0.85) | $ (1.48) |
| 2003 (Restated) | | | | | |
| Operating revenues | $1,828 | $ 1,569 | $1,714 | $1,557 | $ 6,668 |
| Loss on long-lived assets | 14 | 395 | 54 | 397 | 860 |
| Western Energy Settlement | — | 123 | (20) | 1 | 104 |
| Operating income (loss) | 264 | (272) | 481 | (68) | 405 |
| Income (loss) from continuing operations | $ (207) | $ (297) | $ 65 | $ (166)[2] | $ (605) |
| Discontinued operations, net of income taxes[1] | (215) | (939) | (41) | (119)[2] | (1,314) |
| Cumulative effect of accounting changes, net of income taxes | (9) | — | — | — | (9) |
| Net income (loss) | $ (431) | $(1,236) | $ 24 | $ (285) | $(1,928) |
| Basic and diluted earnings per common share | | | | | |
| Income (loss) from continuing operations | $(0.34) | $ (0.50) | $ 0.11 | $(0.27)[2] | $ (1.01) |
| Discontinued operations, net of income taxes | (0.36) | (1.57) | (0.07) | (0.20)[2] | (2.20) |
| Cumulative effect of accounting changes, net of income taxes | (0.02) | — | — | — | (0.02) |
| Net income (loss) | $(0.72) | $ (2.07) | $ 0.04 | $(0.47) | $ (3.23) |

(1) Our petroleum markets operations, our Canadian and certain other international natural gas and oil production operations, and our coal mining operations are classified as discontinued operations (See Note 3 for further discussion).

(2) Amounts previously reported for loss from continuing operations were $(84) million or $(0.14) per share, and the loss for discontinued operations, net of income taxes was $(201) million or $(0.33) per share. See Note 1 to the consolidated financial statements for a discussion of the impact on the full year financial statements.

## Supplemental Natural Gas and Oil Operations (Unaudited)

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 the United States and Brazil. In the United States, we have onshore operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. All of our proved reserves are in the United States and Brazil. We have excluded information relating to our natural gas and oil operations in Canada, Indonesia and Hungary from the following disclosures. We classified these operations as discontinued operations beginning in the second quarter of 2004 based on our decision to exit these operations.

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 | Brazil | Worldwide |
|---|---|---|---|
| 2004 | | | |
| Natural gas and oil properties: | | | |
| Costs subject to amortization[1] | $14,211 | $337 | $14,548 |
| Costs not subject to amortization | 308 | 112 | 420 |
| | 14,519 | 449 | 14,968 |
| Less accumulated depreciation, depletion and amortization | 11,130 | 138 | 11,268 |
| Net capitalized costs | $ 3,389 | $311 | $ 3,700 |
| FAS143 abandonment liability | $ 252 | $ 4 | $ 256 |
| 2003 | | | |
| Natural gas and oil properties: | | | |
| Costs subject to amortization[1] | $14,052 | $146 | $14,198 |
| Costs not subject to amortization | 371 | 117 | 488 |
| | 14,423 | 263 | 14,686 |
| Less accumulated depreciation, depletion and amortization | 11,216 | 58 | 11,274 |
| Net capitalized costs | $ 3,207 | $205 | $ 3,412 |
| FAS 143 abandonment liability | $ 210 | $ — | $ 210 |

(1) As of January 1, 2003, we adopted SFAS No. 143, which is further discussed in Note 1. Included in our costs subject to amortization at December 31, 2004 and 2003 are SFAS No. 143 asset values of $154 million and $124 million for the United States and $3 million and $0.2 million for Brazil.

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

| | United States | Brazil | Worldwide |
|---|---|---|---|
| 2004 | | | |
| Property acquisition costs | | | |
| Proved properties | $ 33 | $ 69 | $ 102 |
| Unproved properties | 32 | 3 | 35 |
| Exploration costs[1] | 185 | 25 | 210 |
| Development costs[1] | 395 | 1 | 396 |
| Costs expended in 2004 | 645 | 98 | 743 |
| Asset retirement obligation costs | 30 | 3 | 33 |
| Total costs incurred | $ 675 | $101 | $ 776 |

| | United States | Brazil | Worldwide |
|---|---|---|---|
| 2003 | | | |
| Property acquisition costs | | | |
| Proved properties | $ 10 | $ — | $ 10 |
| Unproved properties | 35 | 4 | 39 |
| Exploration costs[1] | 467 | 95 | 562 |
| Development costs[1] | 668 | — | 668 |
| Costs expended in 2003 | 1,180 | 99 | 1,279 |
| Asset retirement obligation costs[2] | 124 | — | 124 |
| Total costs Incurred | $1,304 | $ 99 | $1,403 |
| 2002 | | | |
| Property acquisition costs | | | |
| Proved properties | $ 362 | $ — | $ 362 |
| Unproved properties | 29 | 9 | 38 |
| Exploration costs | 524 | 45 | 569 |
| Development costs | 1,242 | — | 1,242 |
| Total costs incurred | $2,157 | $ 54 | $2,211 |

(1) Excludes approximately $110 million and $130 million that was paid in 2004 and 2003 under net profits agreements described beginning on page 178.

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. The cumulative effect of adopting SFAS No. 143 was $3 million.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $44 million, $58 million, and $76 million and capitalized interest of $22 million, $19 million and $10 million for the years ended December 31, 2004, 2003 and 2002.

In our January 1, 2005 reserve report, the amounts estimated to be spent in 2005, 2006 and 2007 to develop our worldwide booked proved undeveloped reserves are $182 million, $251 million and $218 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2004, pending determination of proved reserves (in millions):

| | Cumulative Balance | Costs Excluded for Years Ended December 31 | | | Cumulative Balance |
|---|---|---|---|---|---|
| | December 31, 2004 | 2004 | 2003 | 2002 | December 31, 2001 |
| Worldwide[1][2] | | | | | |
| Acquisition | $209 | $ 76 | $ 51 | $ 61 | $21 |
| Exploration | 178 | 62 | 92 | 18 | 6 |
| Development | 33 | 1 | 3 | 27 | 2 |
| | $420 | $139 | $146 | $106 | $29 |

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

(2) Includes capitalized interest of $20 million, $6 million, and less than $1 million for the years ended December 31, 2004, 2003, and 2002.

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 2005 through 2008. Our total amortization expense per Mcfe for the United States was $1.84, $1.40, and $1.05 in 2004, 2003, and 2002 and $2.02 for Brazil in 2004. We had no production in Brazil during 2003 and 2002. Included in our worldwide depreciation, depletion, and amortization expense is accretion expense of $0.08/Mcfe and $0.06/Mcfe for 2004 and 2003 attributable to SFAS No. 143 which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil, and condensate, and changes in these reserves at December 31, 2004 are presented below. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 88 percent of our properties. The total estimate of proved reserves prepared by Ryder Scott was within four percent of our internally prepared estimates presented in these tables. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Ryder Scott was retained by and reports to the Audit Committee of our Board of Directors. The properties reviewed by Ryder Scott represented 88 percent of our proved properties based on value. The tables below exclude our Power segment's equity interest in Sengkang in Indonesia and Aguaytia in Peru. Combined proved reserves balances for these interests were 132,336 MMcf of natural gas and 2,195 MBbls of oil, condensate and NGL for total natural gas equivalents of 145,507 MMcfe, all net to our ownership interests.

| | Natural Gas (in Bcf) | | |
|---|---|---|---|
| | United States | Brazil | Worldwide |
| Net proved developed and undeveloped reserves[1] | | | |
| January 1, 2002 | 2,799 | — | 2,799 |
| Revisions of previous estimates | (155) | — | (155) |
| Extensions, discoveries and other | 829 | — | 829 |
| Purchases of reserves in place | 142 | — | 142 |
| Sales of reserves in place | (657) | — | (657) |
| Production | (470) | — | (470) |
| December 31, 2002 | 2,488 | — | 2,488 |
| Revisions of previous estimates | (24) | — | (24) |
| Extensions, discoveries and other | 405 | — | 405 |
| Purchases of reserves in place | 2 | — | 2 |
| Sales of reserves in place[2] | (471) | — | (471) |
| Production | (339) | — | (339) |
| December 31, 2003 | 2,061 | — | 2,061 |
| Revisions of previous estimates | (172) | — | (172) |
| Extensions, discoveries and other | 79 | 38 | 117 |
| Purchases of reserves in place | 15 | 38 | 53 |
| Sales of reserves in place[2] | (21) | — | (21) |
| Production | (238) | (7) | (245) |
| December 31, 2004 | 1,724 | 69 | 1,793 |
| Proved developed reserves | | | |
| December 31, 2002 | 1,799 | — | 1,799 |
| December 31, 2003 | 1,428 | — | 1,428 |
| December 31, 2004 | 1,287 | 54 | 1,341 |

(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) Sales of reserves in place include 20,729 MMcf and 28,779 MMcf of natural gas conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page 178.

| | Oil and Condensate (in MBbls) | | |
|---|---|---|---|
| | United States | Brazil | Worldwide |
| Net proved developed and undeveloped reserves[1] | | | |
| January 1, 2002 | 45,153 | — | 45,153 |
| Revisions of previous estimates | 1,552 | — | 1,552 |
| Extensions, discoveries and other | 7,921 | — | 7,921 |
| Purchases of reserves in place | 62 | — | 62 |
| Sales of reserves in place | (3,754) | — | (3,754) |
| Production | (12,580) | — | (12,580) |
| December 31, 2002 | 38,354 | — | 38,354 |
| Revisions of previous estimates | 895 | — | 895 |
| Extensions, discoveries and other | 5,000 | 20,543 | 25,543 |
| Purchases of reserves in place | 5 | — | 5 |
| Sales of reserves in place[2] | (4,328) | — | (4,328) |
| Production | (7,555) | — | (7,555) |
| December 31, 2003 | 32,371 | 20,543 | 52,914 |
| Revisions of previous estimates | (999) | 252 | (747) |
| Extensions, discoveries and other | 2,214 | 1,848 | 4,062 |
| Purchases of reserves in place | — | 1,848 | 1,848 |
| Sales of reserves in place[2] | (1,276) | — | (1,276) |
| Production | (4,979) | (320) | (5,299) |
| December 31, 2004 | 27,331 | 24,171 | 51,502 |
| Proved developed reserves | | | |
| December 31, 2002 | 28,554 | — | 28,554 |
| December 31, 2003 | 22,821 | — | 22,821 |
| December 31, 2004 | 19,641 | 2,613 | 22,254 |

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

(2) Sales of reserves in place include 1,276 MBbl and 1,098 MBbl of liquids conveyed to third parties under net profits agreements in 2004 and 2003 as described beginning on page 178.

| | NGL (in MBbls) | | |
|---|---|---|---|
| | United States | Brazil | Worldwide |
| Net proved developed and undeveloped reserves[1] | | | |
| January 1, 2002 | 28,874 | — | 28,874 |
| Revisions of previous estimates | (2,289) | — | (2,289) |
| Extensions, discoveries and other | 6,820 | — | 6,820 |
| Purchases of reserves in place | — | — | — |
| Sales of reserves in place | (7,916) | — | (7,916) |
| Production | (3,882) | — | (3,882) |
| December 31, 2002 | 21,607 | — | 21,607 |
| Revisions of previous estimates | (2,717) | — | (2,717) |
| Extensions, discoveries and other | 1,795 | — | 1,795 |
| Purchases of reserves in place | 27 | — | 27 |
| Sales of reserves in place[2] | (504) | — | (504) |
| Production | (4,223) | — | (4,223) |
| December 31, 2003 | 15,985 | — | 15,985 |
| Revisions of previous estimates | 724 | — | 724 |
| Extensions, discoveries and other | 58 | — | 58 |
| Purchases of reserves in place | — | — | — |
| Sales of reserves in place[2] | (47) | — | (47) |
| Production | (3,519) | — | (3,519) |
| December 31, 2004 | 13,201 | — | 13,201 |
| Proved developed reserves | | | |
| December 31, 2001 | 17,526 | — | 17,526 |
| December 31, 2002 | 14,088 | — | 14,088 |
| December 31, 2003 | 11,943 | — | 11,943 |

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

(2) Sales of reserves in place include 47 MBbl and 194 MBbl of NGL conveyed to third parties under net profits agreements in 2004 and 2003 as described below.

During 2004, we had approximately 174 Bcfe of negative reserve revisions in the United States that were largely performance-driven. Our reserve revisions were primarily concentrated onshore in our coal bed methane operations and offshore in the Gulf of Mexico:

*Onshore.* The onshore region recorded 71 Bcfe of negative reserve revisions. All of the negative reserve revisions are related to performance results from producing wells or the recent drilling program coupled with the related impact on booked proven undeveloped locations. In certain areas of the Arkoma and Black Warrior Basins, wells drilled in late 2003 had positive initial results; however, subsequent drilling and additional production history resulted in 70 Bcfe of negative revisions. In the Holly Field of North Louisiana, 14 Bcfe of reserves were revised downward as a result of production performance. These negative revisions were offset by better-than-anticipated performance in the Rockies and other Arklatex fields, resulting in positive reserve revisions of 13 Bcfe.

*Texas Gulf Coast.* The Texas Gulf Coast region recorded 26 Bcfe of negative reserve revisions. The negative revisions were comprised of approximately 7 Bcfe of performance revisions to proved producing wells, approximately 6 Bcfe due to mechanical failures in five wells, and approximately 13 Bcfe due to lower-than-expected results from the 2004 development drilling program.

*Offshore.* The offshore region recorded 77 Bcfe of negative reserve revisions in the Gulf of Mexico. Approximately 10 Bcfe of the revisions is a result of mechanical failures, and approximately 25 Bcfe is due to producing well performance. The remaining 42 Bcfe resulted from the drilling of development wells and adjustments to proved undeveloped reserves as a result of production performance in offsetting locations.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the 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 accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. 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 we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. 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, 2004. However in January 2005, we announced two acquisitions in east Texas and south Texas for $211 million. In March 2005, we acquired the interest of one of the parties in our net profits interest drilling program for $62 million. These acquisitions added properties with approximately 139 Bcfe of existing proved reserves and 52 MMcfe/d of current production.

In 2003, we entered into agreements to sell interests in a maximum of 124 wells to Lehman Brothers and a subsidiary of Nabors Industries. As these wells are developed, Lehman and Nabors will pay 70 percent of the drilling and development costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, Lehman and Nabors receive an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 70 percent of the aggregate net profits of all wells until they have recovered 117.5 percent of their aggregate investment. Upon this recovery, the net profits interest will convert to a 2 percent overriding royalty interest in the wells for the remainder of the well's productive life. We do not guarantee a return or the recovery of Lehman and Nabor's costs. All parties to the agreement have the right to cease participation in the agreement at any time, at which time Lehman or Nabors will continue to receive its net profits interest on wells previously started, but will relinquish its right to participate in any future wells. During 2004, we sold interests in 54 wells and total proved reserves of 20,729 MMcf of natural gas and 1,323 MBbl of oil and natural gas liquids. They have paid $110 million of drilling and development costs and were paid $152 million of the revenues net of $11 million of expenses associated with these wells for the year ended December 31, 2004. In March 2005, we acquired all of the interests held by the Lehman subsidiary for $62 million.

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

| | United States | Brazil | Worldwide |
|---|---|---|---|
| 2004 | | | |
| Net Revenues | | | |
| Sales to external customers | $ 518 | $27 | $ 545 |
| Affiliated sales | 1,137 | (1) | 1,136 |
| Total | 1,655 | 26 | 1,681 |
| Production costs[1] | (210) | — | (210) |
| Depreciation, depletion and amortization[2] | (530) | (18) | (548) |
| | 915 | 8 | 923 |
| Income tax (expense) benefit | (333) | (3) | (336) |
| Results of operations from producing activities | $ 582 | $ 5 | $ 587 |
| 2003 | | | |
| Net Revenues | | | |
| Sales to external customers | $ 191 | $— | $ 191 |
| Affiliated sales | 1,868 | — | 1,868 |
| Total | 2,059 | — | 2,059 |
| Production costs[1] | (229) | — | (229) |
| Depreciation, depletion and amortization[2] | (576) | — | (576) |
| Ceiling test charges | — | (5) | (5) |
| | 1,254 | (5) | 1,249 |
| Income tax (expense) benefit | (449) | 2 | (447) |
| Results of operations from producing activities | $ 805 | $(3) | $ 802 |
| 2002 | | | |
| Net Revenues | | | |
| Sales to external customers | $ 134 | $— | $ 134 |
| Affiliated sales | 1,677 | — | 1,677 |
| Total | 1,811 | — | 1,811 |
| Production costs[1] | (284) | — | (284) |
| Depreciation, depletion and amortization | (599) | — | (599) |
| Gain on long-lived assets | 2 | — | 2 |
| | 930 | — | 930 |
| Income tax (expense) benefit | (327) | — | (327) |
| Results of operations from producing activities | $ 603 | $— | $ 603 |

(1) Production cost includes lease operating costs and production related taxes, including ad valorem and severance taxes.

(2) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. Our depreciation, depletion and amortization includes accretion expense for SFAS 143 abandonment liabilities of $23 million primarily for the United States for both 2004 and 2003.

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

| | United States | Brazil | Worldwide |
|---|---|---|---|
| 2004 | | | |
| Future cash inflows[1] | $11,895 | $1,077 | $12,972 |
| Future production costs | (3,585) | (135) | (3,720) |
| Future development costs | (1,234) | (274) | (1,508) |
| Future income tax expenses | (1,184) | (141) | (1,325) |
| Future net cash flows | 5,892 | 527 | 6,419 |
| 10% annual discount for estimated timing of cash flows | (2,004) | (219) | (2,223) |
| Standardized measure of discounted future net cash flows | $ 3,888 | $ 308 | $ 4,196 |
| Standardized measure of discounted future net cash flows, including effects of hedging activities | $ 3,907 | $ 305 | $ 4,212 |
| 2003 | | | |
| Future cash inflows[1] | $13,302 | $ 588 | $13,890 |
| Future production costs | (3,025) | (65) | (3,090) |
| Future development costs | (1,325) | (236) | (1,561) |
| Future income tax expenses | (1,695) | (75) | (1,770) |
| Future net cash flows | 7,257 | 212 | 7,469 |
| 10% annual discount for estimated timing of cash flows | (2,449) | (128) | (2,577) |
| Standardized measure of discounted future net cash flows | $ 4,808 | $ 84 | $ 4,892 |
| Standardized measure of discounted future net cash flows, including effects of hedging activities | $ 4,759 | $ 84 | $ 4,843 |
| 2002 | | | |
| Future cash inflows[1] | $12,847 | $ — | $12,847 |
| Future production costs | (2,924) | — | (2,924) |
| Future development costs | (1,361) | — | (1,361) |
| Future income tax expenses | (1,960) | — | (1,960) |
| Future net cash flows | 6,602 | — | 6,602 |
| 10% annual discount for estimated timing of cash flows | (2,293) | — | (2,293) |
| Standardized measure of discounted future net cash flows | $ 4,309 | $ — | $ 4,309 |
| Standardized measure of discounted future net cash flows, including effects of hedging activities | $ 4,266 | $ — | $ 4,266 |

(1) United States excludes $1 million, $104 million and $85 million of future net cash outflows attributable to hedging activities in the years 2004, 2003 and 2002. Brazil excludes $5 million of future net cash outflows attributable to hedging activities in 2004.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $6.22 per MMbtu for natural gas and $43.45 per barrel of oil at December 31, 2004. Adjustments for transportation and other charges resulted in a net price of $5.99 per Mcf of gas, $42.11 per barrel of oil and $32.13 per barrel of NGL at December 31, 2004. 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, capital availability, and corporate investment criteria.

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

| | Years Ended December 31,[1],[2] | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | | (In Millions) | |
| Sales and transfers of natural gas and oil produced net of production costs | $(1,470) | $(1,829) | $(1,526) |
| Net changes in prices and production costs | 29 | 1,586 | 3,301 |
| Extensions, discoveries and improved recovery, less related costs | 268 | 1,105 | 1,561 |
| Changes in estimated future development costs | 4 | (16) | 17 |
| Previously estimated development costs incurred during the period | 156 | 220 | 275 |
| Revision of previous quantity estimates | (453) | (94) | (348) |
| Accretion of discount | 568 | 526 | 275 |
| Net change in income taxes | 257 | 159 | (934) |
| Purchases of reserves in place | 114 | 5 | 284 |
| Sale of reserves in place | (75) | (1,229) | (1,418) |
| Change in production rates, timing and other | (94) | 150 | 93 |
| Net change | $ (696) | $ 583 | $ 1,580 |

[1] This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.
[2] Includes operations in the United States and Brazil.

## SCHEDULE II

## EL PASO CORPORATION
## VALUATION AND QUALIFYING ACCOUNTS

### Years Ended December 31, 2004, 2003 and 2002
### (In millions)

| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Deductions | Charged to Other Accounts | Balance at End of Period |
|---|---|---|---|---|---|
| 2004 | | | | | |
| Allowance for doubtful accounts | $ 273 | $(48) | $ (22)[1] | $ (4) | $ 199 |
| Valuation allowance on deferred tax assets | 9 | 46[3] | (4) | — | 51 |
| Legal reserves | 1,169 | 145 | (655)[5] | (67) | 592 |
| Environmental reserves | 412 | 17 | (51)[5] | 2 | 380 |
| Regulatory reserves | 13 | — | (12)[5] | — | 1 |
| 2003 | | | | | |
| Allowance for doubtful accounts | $ 176 | $ 18 | $ (31)[1] | $ 110[2] | $ 273 |
| Valuation allowance on deferred tax assets | 72 | 4 | (68)[3] | 1 | 9 |
| Legal reserves | 1,031 | 180[4] | (43)[5] | 1 | 1,169 |
| Environmental reserves | 389 | 8 | (52)[5] | 67[6] | 412 |
| Regulatory reserves | 24 | 32 | (43)[5] | — | 13 |
| 2002 | | | | | |
| Allowance for doubtful accounts | $ 117 | $ 30 | $ (14)[1] | $ 43[2] | $ 176 |
| Valuation allowance on deferred tax assets | 28 | 46[3] | (2) | — | 72 |
| Legal reserves | 149 | 954[4] | (74)[5] | 2 | 1,031 |
| Environmental reserves | 468 | (3) | (63) | (13) | 389 |
| Regulatory reserves | 34 | 48 | (59)[5] | 1 | 24 |

(1) Relates primarily to accounts written off.

(2) Relates primarily to receivables from trading counterparties, reclassified due to bankruptcy or declining credit that have been accounted for within our price risk management activities.

(3) Relates primarily to valuation allowances for deferred tax assets related to the Western Energy Settlement, foreign ceiling test charges, foreign asset impairments and net operating loss carryovers.

(4) Relates to our Western Energy Settlement of $104 million in 2003 and $899 million in 2002. In June 2004, we released approximately $602 million to the settling parties (including approximately $568 million from escrow) and correspondingly reduced our liability by this amount.

(5) Relates primarily to payments for various litigation reserves, including the Western Energy Settlement, environmental remediation reserves or revenue crediting and rate settlement reserves.

(6) Relates primarily to liabilities previously classified in our petroleum discontinued operations, but reclassified as continuing operations due to our retention of these obligations.

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

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

As of December 31, 2004, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, our CEO and CFO concluded that as a result of the material weaknesses discussed below, our disclosure controls and procedures were not effective as of December 31, 2004. Because of these material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the year ended December 31, 2004, were fairly presented in all material respects in accordance with generally accepted accounting principles.

### Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including the CEO and CFO, we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, we used the criteria established in *Internal Control — Integrated Framework* issued by the *Committee of Sponsoring Organizations of the Treadway Commission (COSO)*.

As of December 31, 2004, we did not maintain effective controls over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. A specific description of these control deficiencies, which we concluded are material weaknesses that existed as of December 31, 2004, is discussed below. A material weakness is a control deficiency, or combination of control deficiencies, that results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

*Access to Financial Application Programs and Data.* At December 31, 2004, we did not maintain effective controls over access to financial application programs and data at each of our operating segments. Specifically, we identified internal control deficiencies with respect to inadequate design of and compliance with our security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and a lack of independent monitoring of access to various systems by our information technology staff, as well as certain users that require unrestricted security access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of our financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, operating expenses, risk management assets and liabilities, and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

*Account Reconciliations.* At December 31, 2004, we did not maintain effective controls over the preparation and review of account reconciliations related to accounts such as prepaid insurance, accounts receivable, other assets and liabilities, and taxes other than income taxes. Specifically, we found various instances in our Power and Marketing and Trading businesses where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. We also found instances within the company where accounts were not being reconciled and reviewed by individuals with adequate accounting experience and training. These control deficiencies resulted in adjustments impacting the fourth quarter of 2004 financial statements. Furthermore, these control deficiencies could result in a misstatement to the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

*Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities.* At December 31, 2004, we did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. We identified control deficiencies related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment amounts, and accounting for divestiture of assets. These control deficiencies resulted in the restatement of our 2002 and, as described in the fourth paragraph of Note 1, the 2003 financial statements, and related 2003 fourth quarter information as reflected in this Report on Form 10-K/A, as well as adjustments impacting the fourth quarter of our 2004 financial statements. The matters discussed in the fourth paragraph of Note 1 of the consolidated financial statements resulting from the material weakness described herein do not constitute an additional material weakness and have not caused us to modify our previously issued Report on Internal Control Over Financial Reporting. These control deficiencies could result in a misstatement in the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Because of the material weaknesses described above, management has concluded that, as of December 31, 2004, we did not maintain effective internal control over financial reporting, based on the criteria established in *Internal Control — Integrated Framework* issued by the COSO. Management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

**Changes in Internal Control over Financial Reporting**

*Changes Implemented Through December 31, 2004.* During the course of 2004, management, with the oversight of our Audit Committee, devoted considerable effort to remediating deficiencies and to making improvements in our internal control over financial reporting. These improvements include the following enhancements in our internal controls over financial reporting:

- Improving in the area of estimating oil and gas reserves, including changes in the composition of our Board of Directors and management by adding persons with greater experience in the oil and gas industry, creating a centralized reserve reporting function and internal committee that provides oversight of the reporting function, continuing the use of third party reserve engineering firms to perform an independent assessment of our proved reserves, and enhancing documentation with regard to the procedures and controls for recording proved reserves;

- Implementing changes to our systems and procedures to segregate responsibilities for manual journal entry preparation and procurement activities; and
- Implementing formal training to educate appropriate personnel on management's responsibilities mandated by the Sarbanes Oxley Act, Section 404, the components of the internal control framework on which we rely and its relationship to our core values.

*Changes in 2005.* Since December 31, 2004, we have taken action to correct the control deficiencies that resulted in the material weaknesses described in our report above including implementing monitoring controls in our information technology areas over users who require unrestricted access to perform their job responsibilities and formalizing and issuing a company-wide account reconciliation policy and providing training on the appropriate application of such policy. Other remedial actions have also been identified and are in the process of being implemented.

**ITEM 9B. OTHER INFORMATION**

None.

## PART III

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

The information included under the captions, "Proposal No. 1 — Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2005 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

As a result of the promulgation of Rule 10b5-1, we allow certain officers and directors to establish pre-established trading plans. Rule 10b5-1 allows certain officers and directors to establish written programs that permit an independent person who is not aware of inside information at the time of the trade to execute pre-established trades of our securities for the officer or director according to fixed parameters. As of March 10, 2005, no officer or director has a current trading plan. However, we intend to disclose the existence of any trading plan in compliance with Rule 10b5-1 in future filings with the SEC.

### ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in our proxy statement for the 2005 Annual Meeting of Stockholders is incorporated herein by reference.

### ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" in our proxy statement for the 2005 Annual Meeting of Stockholders is incorporated herein by reference.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information appearing under the caption "Certain Relationships and Related Transactions" in our proxy statement for the 2005 Annual Meeting of Stockholders is incorporated herein by reference.

### ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information appearing under the caption "Principal Accountant Fees and Services" in our proxy statement for the 2005 Annual Meeting of Stockholders is incorporated herein by reference.

## PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

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

1. Financial statements.

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



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

**PRICEWATERHOUSECOOPERS LLP**

Report of Independent Registered Public Accounting Firm

To the Partners and the Management Committee of
Midland Cogeneration Venture Limited Partnership:

We have completed an integrated audit of Midland Cogeneration Venture Limited Partnership 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its December 31, 2003 and December 31, 2002 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, partners' equity and cash flows present fairly, in all material respects, the financial position of the Midland Cogeneration Limited Partnership (a Michigan limited partnership) and its subsidiaries (MCV) at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the MCV's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As explained in Note 2 to the financial statements, effective April 1, 2002, Midland Cogeneration Venture Limited Partnership changed its method of accounting for derivative and hedging activities in accordance with Derivative Implementation Group ("DIG") Issue C-16.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting appearing under Item 9(a), that the MCV maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the MCV maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The MCV's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the MCV's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 25, 2005

**MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP**

**CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31,**
**(In Thousands)**

| | 2004 | 2003 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 125,781 | $ 173,651 |
| Accounts and notes receivable — related parties | 54,368 | 43,805 |
| Accounts receivable | 42,984 | 38,333 |
| Gas inventory | 17,509 | 20,298 |
| Unamortized property taxes | 18,060 | 17,672 |
| Derivative assets | 94,977 | 86,825 |
| Broker margin accounts, and prepaid gas costs and expenses | 13,147 | 8,101 |
| Total current assets | 366,826 | 388,685 |
| PROPERTY, PLANT AND EQUIPMENT: | | |
| Property, plant and equipment | 2,466,944 | 2,463,931 |
| Pipeline | 21,432 | 21,432 |
| Total property, plant and equipment | 2,488,376 | 2,485,363 |
| Accumulated depreciation | (1,062,821) | (991,556) |
| Net property, plant and equipment | 1,425,555 | 1,493,807 |
| OTHER ASSETS: | | |
| Restricted investment securities held-to-maturity | 139,410 | 139,755 |
| Derivative assets non-current | 24,337 | 18,100 |
| Deferred financing costs, net of accumulated amortization of $18,498 and $17,285, respectively | 6,467 | 7,680 |
| Prepaid gas costs, spare parts deposit, materials and supplies | 17,782 | 21,623 |
| Total other assets | 187,996 | 187,158 |
| TOTAL ASSETS | $ 1,980,377 | $2,069,650 |
| LIABILITIES AND PARTNERS' EQUITY | | |
| CURRENT LIABILITIES: | | |
| Accounts payable and accrued liabilities | $ 82,693 | $ 57,368 |
| Gas supplier funds on deposit | 19,613 | 4,517 |
| Interest payable | 47,738 | 53,009 |
| Current portion of long-term debt | 76,548 | 134,576 |
| Total current liabilities | 226,592 | 249,470 |
| NON-CURRENT LIABILITIES: | | |
| Long-term debt | 942,097 | 1,018,645 |
| Other | 1,712 | 2,459 |
| Total non-current liabilities | 943,809 | 1,021,104 |
| COMMITMENTS AND CONTINGENCIES (Notes 7 and 8) | | |
| TOTAL LIABILITIES | 1,170,401 | 1,270,574 |
| PARTNERS' EQUITY | 809,976 | 799,076 |
| TOTAL LIABILITIES AND PARTNERS' EQUITY | $ 1,980,377 | $2,069,650 |

The accompanying notes are an integral part of these statements.

## MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

## CONSOLIDATED STATEMENTS OF OPERATIONS
## FOR THE YEARS ENDED DECEMBER 31,
## (In Thousands)

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| OPERATING REVENUES: | | | |
| Capacity | $ 405,415 | $ 404,681 | $ 404,713 |
| Electric | 225,154 | 162,093 | 177,569 |
| Steam | 19,090 | 17,638 | 14,537 |
| Total operating revenues | 649,659 | 584,412 | 596,819 |
| OPERATING EXPENSES: | | | |
| Fuel costs | 413,061 | 254,988 | 255,142 |
| Depreciation | 88,712 | 89,437 | 88,963 |
| Operations | 18,769 | 16,943 | 16,642 |
| Maintenance | 13,508 | 15,107 | 12,666 |
| Property and single business taxes | 28,834 | 30,040 | 27,087 |
| Administrative, selling and general | 11,236 | 9,959 | 8,195 |
| Total operating expenses | 574,120 | 416,474 | 408,695 |
| OPERATING INCOME | 75,539 | 167,938 | 188,124 |
| OTHER INCOME (EXPENSE): | | | |
| Interest and other income | 5,460 | 5,100 | 5,555 |
| Interest expense | (104,618) | (113,247) | (119,783) |
| Total other income (expense), net | (99,158) | (108,147) | (114,228) |
| NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE | (23,619) | 59,791 | 73,896 |
| Cumulative effect of change in method of accounting for derivative option contracts (to April 1, 2002) (Note 2) | — | — | 58,131 |
| NET INCOME (LOSS) | $ (23,619) | $ 59,791 | $ 132,027 |

The accompanying notes are an integral part of these statements.

## MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

### CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
### FOR THE YEARS ENDED DECEMBER 31,
### (In Thousands)

| | General Partners | Limited Partners | Total |
|---|---|---|---|
| BALANCE, DECEMBER 31, 2001 | $468,972 | $ 82,740 | $551,712 |
| Comprehensive Income | | | |
| Net Income | 114,947 | 17,080 | 132,027 |
| Other Comprehensive Income | | | |
| Unrealized gain on hedging activities since beginning of period | 33,311 | 4,950 | 38,261 |
| Reclassification adjustments recognized in net income above | 10,717 | 1,593 | 12,310 |
| Total other comprehensive income | 44,028 | 6,543 | 50,571 |
| Total Comprehensive Income | 158,975 | 23,623 | 182,598 |
| BALANCE, DECEMBER 31, 2002 | $627,947 | $106,363 | $734,310 |
| Comprehensive Income | | | |
| Net Income | 52,056 | 7,735 | 59,791 |
| Other Comprehensive Income | | | |
| Unrealized gain on hedging activities since beginning of period | 34,484 | 5,125 | 39,609 |
| Reclassification adjustments recognized in net income above | (30,153) | (4,481) | (34,634) |
| Total other comprehensive income | 4,331 | 644 | 4,975 |
| Total Comprehensive Income | 56,387 | 8,379 | 64,766 |
| BALANCE, DECEMBER 31, 2003 | $684,334 | $114,742 | $799,076 |
| Comprehensive Income | | | |
| Net Loss | (20,563) | (3,056) | (23,619) |
| Other Comprehensive Income | | | |
| Unrealized gain on hedging activities since beginning of period | 62,292 | 9,256 | 71,548 |
| Reclassification adjustments recognized in net income above | (32,239) | (4,790) | (37,029) |
| Total other comprehensive income | 30,053 | 4,466 | 34,519 |
| Total Comprehensive Income | 9,490 | 1,410 | 10,900 |
| BALANCE, DECEMBER 31, 2004 | $693,824 | $116,152 | $809,976 |

The accompanying notes are an integral part of these statements.

**MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**FOR THE YEARS ENDED DECEMBER 31,**
**(In Thousands)**

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income (loss) | $ (23,619) | $ 59,791 | $ 132,027 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation and amortization | 89,925 | 90,792 | 90,430 |
| Cumulative effect of change in accounting principle | — | — | (58,131) |
| (Increase) decrease in accounts receivable | (15,214) | (1,211) | 48,343 |
| (Increase) decrease in gas inventory | 2,789 | (732) | 133 |
| (Increase) decrease in unamortized property taxes | (388) | 683 | (1,730) |
| (Increase) decrease in broker margin accounts and prepaid expenses | (5,046) | (4,778) | 31,049 |
| (Increase) decrease in derivative assets | 20,130 | 4,906 | (20,444) |
| (Increase) decrease in prepaid gas costs, materials and supplies | 3,841 | (8,704) | 1,376 |
| Increase (decrease) in accounts payable and accrued liabilities | 25,775 | (712) | 8,774 |
| Increase in gas supplier funds on deposit | 15,096 | 4,517 | — |
| Decrease in interest payable | (5,271) | (3,377) | (3,948) |
| Increase (decrease) in other non-current liabilities | (1,197) | 311 | (24) |
| Net cash provided by operating activities | 106,821 | 141,486 | 227,855 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Plant modifications and purchases of plant equipment | (20,460) | (33,278) | (29,529) |
| Maturity of restricted investment securities held-to-maturity | 674,553 | 601,225 | 377,192 |
| Purchase of restricted investment securities held-to-maturity | (674,208) | (602,279) | (374,426) |
| Net cash used in investing activities | (20,115) | (34,332) | (26,763) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Repayment of financing obligation | (134,576) | (93,928) | (182,084) |
| Net cash used in financing activities | (134,576) | (93,928) | (182,084) |
| NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS | (47,870) | 13,226 | 19,008 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | 173,651 | 160,425 | 141,417 |
| CASH AND EQUIVALENTS AT END OF PERIOD | $ 125,781 | $ 173,651 | $ 160,425 |

The accompanying notes are an integral part of these statements.

## MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### (1) The Partnership and Associated Risks

MCV was organized to construct, own and operate a combined-cycle, gas-fired cogeneration facility (the "Facility") located in Midland, Michigan. MCV was formed on January 27, 1987, and the Facility began commercial operation in 1990.

In 1992, MCV had acquired the outstanding common stock of PVCO Corp., a previously inactive company. MCV and PVCO Corp. then entered into a partnership agreement to form MCV Gas Acquisition General Partnership ("MCV GAGP") for the purpose of buying and selling natural gas on the spot market and other transactions involving natural gas activities. PVCO Corp. and MCV GAGP were dissolved on January 30, 2004 and July 2, 2004, respectively, due to inactivity.

The Facility has a net electrical generating capacity of approximately 1500 MW and approximately 1.5 million pounds of process steam capacity per hour. MCV has entered into three principal energy sales agreements. MCV has contracted to (i) supply up to 1240 MW of electric capacity ("Contract Capacity") to Consumers Energy Company ("Consumers") under the Power Purchase Agreement ("PPA"), for resale to its customers through 2025, (ii) supply electricity and steam to The Dow Chemical Company ("Dow") through 2008 and 2015, respectively, under the Steam and Electric Power Agreement ("SEPA") and (iii) supply steam to Dow Corning Corporation ("DCC") under the Steam Purchase Agreement ("SPA") through 2011. From time to time, MCV enters into other sales agreements for the sale of excess capacity and/or energy available above MCV's internal use and obligations under the PPA, SEPA and SPA. Results of operations are primarily dependent on successfully operating the Facility at or near contractual capacity levels and on Consumers' ability to perform its obligations under the PPA. Sales pursuant to the PPA have historically accounted for over 90% of MCV's revenues.

The PPA permits Consumers, under certain conditions, to reduce the capacity and energy charges payable to MCV and/or to receive refunds of capacity and energy charges paid to MCV if the Michigan Public Service Commission ("MPSC") does not permit Consumers to recover from its customers the capacity and energy charges specified in the PPA (the "regulatory-out" provision). Until September 15, 2007, however, the capacity charge may not be reduced below an average capacity rate of 3.77 cents per kilowatt-hour for the available Contract Capacity notwithstanding the "regulatory-out" provision. Consumers and MCV are required to support and defend the terms of the PPA.

The Facility is a qualifying cogeneration facility ("QF") originally certified by the Federal Energy Regulatory Commission ("FERC") under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). In order to maintain QF status, certain operating and efficiency standards must be maintained on a calendar-year basis and certain ownership limitations must be met. In the case of a topping-cycle generating plant such as the Facility, the applicable operating standard requires that the portion of total energy output that is put to some useful purpose other than facilitating the production of power (the "Thermal Percentage") be at least 5%. In addition, the Facility must achieve a PURPA efficiency standard (the sum of the useful power output plus one-half of the useful thermal energy output, divided by the energy input (the "Efficiency Percentage")) of at least 45%. If the Facility maintains a Thermal Percentage of 15% or higher, the required Efficiency Percentage is reduced to 42.5%. Since 1990, the Facility has achieved the applicable Thermal and Efficiency Percentages. For the twelve months ended December 31, 2004, the Facility achieved a Thermal Percentage of 15.6% and an Efficiency Percentage of 47.6%. The loss of QF status could, among other things, cause MCV to lose its rights under PURPA to sell power from the Facility to Consumers at Consumers' "avoided cost" and subject MCV to additional federal and state regulatory requirements.

The Facility is wholly dependent upon natural gas for its fuel supply and a substantial portion of the Facility's operating expenses consist of the costs of natural gas. MCV recognizes that its existing gas contracts are not sufficient to satisfy the anticipated gas needs over the term of the PPA and, as such, no assurance can be given as to the availability or price of natural gas after the expiration of the existing gas contracts. In addition, to the extent that the costs associated with production of electricity rise faster than the energy charge payments, MCV's financial performance will be negatively affected. The extent of such impact will depend upon the amount of the average energy charge payable under the PPA, which is based upon costs incurred at Consumers' coal-fired plants and upon the amount of energy scheduled by Consumers for delivery under the PPA. However, given the unpredictability of these factors, the overall economic impact upon MCV of changes in energy charges payable under the PPA and in future fuel costs under new or existing contracts cannot accurately be predicted.

At both the state and federal level, efforts continue to restructure the electric industry. A significant issue to MCV is the potential for future regulatory denial of recovery by Consumers from its customers of above market PPA costs Consumers pays MCV. At the state level, the MPSC entered a series of orders from June 1997 through February 1998 (collectively the "Restructuring Orders"), mandating that utilities "wheel" third-party power to the utilities' customers, thus permitting customers to choose their power provider. MCV, as well as others, filed an appeal in the Michigan Court of Appeals to protect against denial of recovery by Consumers of PPA charges. The Michigan Court of Appeals found that the Restructuring Orders do not unequivocally disallow such recovery by Consumers and, therefore, MCV's issues were not ripe for appellate review and no actual controversy regarding recovery of costs could occur until 2008, at the earliest. In June 2000, the State of Michigan enacted legislation which, among other things, states that the Restructuring Orders (being voluntarily implemented by Consumers) are in compliance with the legislation and enforceable by the MPSC. The legislation provides that the rights of parties to existing contracts between utilities (like Consumers) and QFs (like MCV), including the rights to have the PPA charges recovered from customers of the utilities, are not abrogated or diminished, and permits utilities to securitize certain stranded costs, including PPA charges.

In 1999, the U.S. District Court granted summary judgment to MCV declaring that the Restructuring Orders are preempted by federal law to the extent they prohibit Consumers from recovering from its customers any charge for avoided costs (or "stranded costs") to be paid to MCV under PURPA pursuant to the PPA. In 2001, the United States Court of Appeals ("Appellate Court") vacated the U.S. District Court's 1999 summary judgment and ordered the case dismissed based upon a finding that no actual case or controversy existed for adjudication between the parties. The Appellate Court determined that the parties' dispute is hypothetical at this time and the QFs' (including MCV) claims are premised on speculation about how an order might be interpreted by the MPSC, in the future.

Two significant issues that could affect MCV's future financial performance are the price of natural gas and Consumers' ability/obligation to pay PPA charges. Natural gas prices have historically been volatile and presently there is no consensus among forecasters on the price or range of future prices of natural gas. Even with the approved Resource Conservation Agreement and Reduced Dispatch Agreement, if gas prices continue at present levels or increase, the economics of operating the Facility may be adversely affected. Consumers' ability/obligation to pay PPA charges may be affected by an MPSC order denying Consumers recovery from ratepayers. This issue is likely to be addressed in the timeframe of 2007 or beyond. MCV continues to monitor and participate in these matters as appropriate, and to evaluate potential impacts on both cash flows and recoverability of the carrying value of property, plant and equipment. MCV management cannot, at this time, predict the impact or outcome of these matters.

### (2) Significant Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Following is a discussion of MCV's significant accounting policies.

*Principles of Consolidation*

The consolidated financial statements included the accounts of MCV and its wholly-owned subsidiaries, PVCO Corp. and MCV GAGP. Previously, all material transactions and balances among entities, which comprise MCV, had been eliminated in the consolidated financial statements. The 2004 dissolution of these wholly-owned subsidiaries had no impact on the financial position and results of operations.

*Revenue Recognition*

MCV recognizes revenue for the sale of variable energy and fixed energy when delivered. Capacity and other installment revenues are recognized based on plant availability or other contractual arrangements.

*Fuel Costs*

MCV's fuel costs are those costs associated with securing natural gas, transportation and storage services necessary to generate electricity and steam from the Facility. These costs are recognized in the income statement based upon actual volumes burned to produce the delivered energy. In addition, MCV engages in certain cost mitigation activities to offset the fixed charges MCV incurs for these activities. The gains or losses resulting from these activities have resulted in net gains of approximately $6.7 million, $7.7 million and $3.9 million for the years ended 2004, 2003 and 2002, respectively. These net gains are reflected as a component of fuel costs.

In July 2000, in response to rapidly escalating natural gas prices and since Consumers' electric rates were frozen, MCV entered into a series of transactions with Consumers whereby Consumers agreed to reduce MCV's dispatch level and MCV agreed to share with Consumers the savings realized by not having to generate electricity ("Dispatch Mitigation"). On January 1, 2004, Dispatch Mitigation ceased and Consumers began dispatching MCV pursuant to a 915 MW settlement and a 325 MW settlement "availability caps" provision (i.e., minimum dispatch of 1100 MW on- and off-peak ("Forced Dispatch")). In 2004, MCV and Consumers entered into a Resource Conservation Agreement ("RCA") and a Reduced Dispatch Agreement ("RDA") which, among other things, provides that Consumers will economically dispatch MCV, if certain conditions are met. Such dispatch is expected to reduce electric production from what is occurring under the Forced Dispatch, as well as decrease gas consumption by MCV. The RCA provides that Consumers has a right of first refusal to purchase, at market prices, the gas conserved under the RCA. The RCA and RDA provide for the sharing of savings realized by not having to generate electricity. The RCA and RDA were approved by an order of the MPSC on January 25, 2005 and MCV and Consumers accepted the terms of the MPSC order making the RCA and RDA effective as of January 27, 2005. This MPSC order is subject to appeal by other parties. MCV management cannot predict the final outcome of any such appeal. While awaiting approval of this order, effective October 23, 2004, MCV and Consumers entered into an interim Dispatch Mitigation program for energy dispatch above 1100 MW up to 1240 MW of Contract Capacity under the PPA. This interim program, which was structured very similarly to the RCA and RDA, was terminated on January 27, 2005 with the effective date of the RCA/RDA. For the twelve months ended December 31, 2004, 2003 and 2002, MCV estimates that these programs have resulted in net savings of approximately $1.6 million, $13.0 million and $2.5 million, a portion of which is realized in reduced maintenance expenditures in future years.

*Accounts Receivable*

Accounts receivable and accounts receivable-related parties are recorded at the billed amount and do not bear interest. MCV evaluates the need for an allowance for doubtful accounts using MCV's best estimate of the amount of probable credit losses. At December 31, 2004 and 2003, no allowance was provided since typically all receivables are collected within 30 days of each month end.

*Inventory*

MCV's inventory of natural gas is stated at the lower of cost or market, and valued using the last-in, first-out ("LIFO") method. Inventory includes the costs of purchased gas, variable transportation and storage. The amount of reserve to reduce inventories from first-in, first-out ("FIFO") basis to the LIFO basis at December 31, 2004 and 2003, was $10.3 million and $8.4 million, respectively. Inventory cost, determined on a FIFO basis, approximates current replacement cost.

*Materials and Supplies*

Materials and supplies are stated at the lower of cost or market using the weighted average cost method. The majority of MCV's materials and supplies are considered replacement parts for MCV's Facility.

*Depreciation*

Original plant, equipment and pipeline were valued at cost for the constructed assets and at the asset transfer price for purchased and contributed assets, and are depreciated using the straight-line method over an estimated useful life of 35 years, which is the term of the PPA, except for the hot gas path components of the GTGs which are primarily being depreciated over a 25-year life. Plant construction and additions, since commercial operations in 1990, are depreciated using the straight-line method over the remaining life of the plant which currently is 22 years. Major renewals and replacements, which extend the useful life of plant and equipment are capitalized, while maintenance and repairs are expensed when incurred. Major equipment overhauls are capitalized and amortized to the next equipment overhaul. Personal property is depreciated using the straight-line method over an estimated useful life of 5 to 15 years. The cost of assets and related accumulated depreciation are removed from the accounts when sold or retired, and any resulting gain or loss reflected in operating income.

*Federal Income Tax*

MCV is not subject to Federal or State income taxes. Partnership earnings are taxed directly to each individual partner.

*Statement of Cash Flows*

All liquid investments purchased with a maturity of three months or less at time of purchase are considered to be current cash equivalents.

*Fair Value of Financial Instruments*

The carrying amounts of cash and cash equivalents and short-term investments approximate fair value because of the short maturity of these instruments. MCV's short-term investments, which are made up of investment securities held-to-maturity, as of December 31, 2004 and December 31, 2003 have original maturity dates of approximately one year or less. The unique nature of the negotiated financing obligation discussed in Note 6 makes it unnecessary to estimate the fair value of the Owner Participants' underlying debt and equity instruments supporting such financing obligation, since SFAS No. 107 "Disclosures about Fair Value of Financial Instruments" does not require fair value accounting for the lease obligation.

*Accounting for Derivative Instruments and Hedging Activities*

Effective January 1, 2001, MCV adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" which was issued in June 1998 and then amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of SFAS No. 133," SFAS No. 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities — An amendment of FASB Statement No. 133" and SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activity (collectively referred to as "SFAS No. 133"). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges in some cases allows a derivative's gains and losses to offset related results on the hedged item in the income statement or permits recognition of the hedge results in other comprehensive income, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

*Electric Sales Agreements*

MCV believes that its electric sales agreements currently do not qualify as derivatives under SFAS No. 133, due to the lack of an active energy market (as defined by SFAS No. 133) in the State of Michigan and the transportation cost to deliver the power under the contracts to the closest active energy market at the Cinergy hub in Ohio and as such does not record the fair value of these contracts on its balance sheet. If an active energy market emerges, MCV intends to apply the normal purchase, normal sales exception under SFAS No. 133 to its electric sales agreements, to the extent such exception is applicable.

*Natural Gas Supply Contracts*

MCV management believes that its long-term natural gas contracts, which do not contain volume optionality, qualify under SFAS No. 133 for the normal purchases and normal sales exception. Therefore, these contracts are currently not recognized at fair value on the balance sheet.

The FASB issued DIG Issue C-16, which became effective April 1, 2002, regarding natural gas commodity contracts that combine an option component and a forward component. This guidance requires either that the entire contract be accounted for as a derivative or the components of the contract be separated into two discrete contracts. Under the first alternative, the entire contract considered together would not qualify for the normal purchases and sales exception under the revised guidance. Under the second alternative, the newly established forward contract could qualify for the normal purchases and sales exception, while the option contract would be treated as a derivative under SFAS No. 133 with changes in fair value recorded through earnings. At April 1, 2002, MCV had nine long-term gas contracts that contained both an option and forward component. As such, they were no longer accounted for under the normal purchases and sales exception and MCV began mark-to-market accounting of these nine contracts through earnings. As of January 31, 2005, only four contracts of the original nine contracts, which contained an option and forward component remain in effect. In addition, as a result of implementing the RCA/RDA, effective January 27, 2005, MCV has determined that as of the effective date of the RCA/RDA, an additional nine long term contracts (for a total of 13) will no longer be accounted for under the normal purchases and sales exception, per SFAS No. 133 and will result in additional mark-to-market activity in 2005 and beyond. MCV expects future earnings volatility on both the remaining long term gas contracts that contain volume optionality as well as the long term gas contracts under the RCA/RDA that will require mark-to-market recognition on a quarterly basis.

Based on the natural gas prices, at the beginning of April 2002, MCV recorded a $58.1 million gain for the cumulative effect of this accounting change. From April 2002 to December 2004, MCV recorded an additional net mark-to-market loss of $2.3 million for these gas contracts. The cumulative mark-to-market gain through December 31, 2004 of $55.8 million is recorded as a current and non-current derivative asset on the balance sheet, as detailed below. These assets will reverse over the remaining life of these gas contracts, ranging from 2005 to 2007. For the twelve months ended December 31, 2004 and 2003, MCV recorded in "Fuel costs" losses of $19.2 million and $5.0 million, respectively, for net mark-to-market adjustments associated with these contracts. In addition, as of December 31, 2004 and 2003, MCV recorded "Derivative assets" in Current Assets in the amount of $31.4 million and $56.9 million, respectively, and for the same periods recorded "Derivative assets non-current" in Other Assets in the amount of $24.3 million and $18.1 million, respectively, representing the mark-to-market value on these long-term natural gas contracts.

*Natural Gas Supply Futures and Options*

To manage market risks associated with the volatility of natural gas prices, MCV maintains a gas hedging program. MCV enters into natural gas futures contracts, option contracts, and over the counter swap transactions ("OTC swaps") in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are being utilized principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize MCV's existing gas supply, storage and transportation arrangements.

These financial instruments are derivatives under SFAS No. 133 and the contracts that are utilized to secure the anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133, since they hedge the price risk associated with the cost of natural gas. MCV also engages in cost mitigation activities to offset the fixed charges MCV incurs in operating the Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for MCV and do not qualify as hedges under SFAS No. 133. Therefore, the resulting mark-to-market gains and losses from cost mitigation activities are flowed through MCV's earnings.

Cash is deposited with the broker in a margin account at the time futures or options contracts are initiated. The change in market value of these contracts requires adjustment of the margin account balances. The margin account balance as of December 31, 2004 and 2003 was recorded as a current asset in "Broker margin accounts and prepaid expenses," in the amount of $1.4 million and $4.1 million, respectively.

For the twelve months ended December 31, 2004, MCV has recognized in other comprehensive income, an unrealized $34.5 million increase on the futures contracts and OTC swaps, which are hedges of forecasted purchases for plant use of market priced gas. This resulted in a net $65.8 million gain in other comprehensive income as of December 31, 2004. This balance represents natural gas futures, options and OTC swaps with maturities ranging from January 2005 to December 2009, of which $33.4 million of this gain is expected to be reclassified into earnings within the next twelve months. MCV also has recorded, as of December 31, 2004, a $63.6 million current derivative asset in "Derivative assets," representing the mark-to-market gain on natural gas futures for anticipated projected electric and steam sales accounted for as hedges. In addition, for the twelve months ended December 31, 2004, MCV has recorded a net $36.5 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $1.8 million gain in earnings from cost mitigation activities.

For the twelve months ended December 31, 2003, MCV recognized an unrealized $5.0 million increase in other comprehensive income on the futures contracts, which are hedges of forecasted purchases for plant use of market priced gas, which resulted in a $31.3 million gain balance in other comprehensive income as of December 31, 2003. As of December 31, 2003, MCV had recorded a $29.9 million current derivative asset in "Derivative assets." For the twelve months ended December 31, 2003, MCV had recorded a net $35.0 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net $1.0 million gain in earnings from cost mitigation activities.

*New Accounting Standard*

In 2003, the Emerging Issues Task Force ("EITF") issued EITF 03-1 "The Meaning of Other-Than-Temporary Impairment and It's Application to Certain Investments". EITF 03-1 addresses how to determine the meaning of other-than-temporary impairment of certain debt and equity securities, the measurement of an impairment loss and accounting and disclosure considerations subsequent to the recognition of an other-than-temporary impairment. The various sections of EITF 03-1 became effective at various times during 2004. MCV has adopted this guidance and does not expect the application to materially affect it financial position or results of operations, since MCV's investments approximate fair value due to the short maturity of its permitted investments.

### (3) Restricted Investment Securities Held-to-Maturity

Non-current restricted investment securities held-to-maturity have carrying amounts that approximate fair value because of the short maturity of these instruments and consist of the following at December 31 (in thousands):

| | 2004 | 2003 |
|---|---|---|
| Funds restricted for rental payments pursuant to the Overall Lease Transaction | $138,150 | $137,296 |
| Funds restricted for management non-qualified plans | 1,260 | 2,459 |
| Total | $139,410 | $139,755 |

### (4) Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consist of the following at December 31 (in thousands):

| | 2004 | 2003 |
|---|---|---|
| Accounts payable | | |
| Related parties | $12,772 | $ 7,386 |
| Trade creditors | 53,476 | 34,786 |
| Property and single business taxes | 11,833 | 12,548 |
| Other | 4,612 | 2,648 |
| Total | $82,693 | $57,368 |

### (5) Gas Supplier Funds on Deposit

Pursuant to individual gas contract terms with counterparties, deposit amounts or letters of credit may be required by one party to the other based upon the net amount of exposure. The net amount of exposure will vary with changes in market prices, credit provisions and various other factors. Collateral paid or received will be posted by one party to the other based on the net amount of the exposure. Interest is earned on funds on deposit. As of December 31, 2004, MCV is supplying credit support to two gas suppliers; one in the form of a letter of credit in the amount of $2.4 million; and cash on deposit with the other in the amount of $7.3 million. As of December 31, 2004, MCV is holding $19.6 million of cash on deposit from two of MCV's brokers. In addition as of December 31, 2004, MCV is also holding letters of credit totaling $208.6 million from two gas suppliers, of which $184.0 million is a letter of credit from El Paso Corporation ("El Paso"), a related party.

**(6) Long-Term Debt**

Long-term debt consists of the following at December 31 (in thousands):

| | 2004 | 2003 |
|---|---|---|
| Financing obligation, maturing through 2015, payable in semi-annual installments of principal and interest, collateralized by property, plant and equipment | $1,018,645 | $1,153,221 |
| Less current portion | (76,548) | (134,576) |
| Total long-term debt | $ 942,097 | $1,018,645 |

*Financing Obligation*

In June 1990, MCV obtained permanent financing for the Facility by entering into sale and leaseback agreements ("Overall Lease Transaction") with a lessor group, related to substantially all of MCV's fixed assets. Proceeds of the financing were used to retire borrowings outstanding under existing loan commitments, make a capital distribution to the Partners and retire a portion of notes issued by MCV to MEC Development Corporation ("MDC") in connection with the transfer of certain assets by MDC to MCV. In accordance with SFAS No. 98, "Accounting For Leases," the sale and leaseback transaction has been accounted for as a financing arrangement.

The financing obligation utilizes the effective interest rate method, which is based on the minimum lease payments required through the end of the basic lease term of 2015 and management's estimate of additional anticipated obligations after the end of the basic lease term. The effective interest rate during the remainder of the basic lease term is approximately 9.4%.

Under the terms of the Overall Lease Transaction, MCV sold undivided interests in all of the fixed assets of the Facility for approximately $2.3 billion, to five separate owner trusts ("Owner Trusts") established for the benefit of certain institutional investors ("Owner Participants"). U.S. Bank National Association (formerly known as State Street Bank and Trust Company) serves as owner trustee ("Owner Trustee") under each of the Owner Trusts, and leases undivided interests in the Facility on behalf of the Owner Trusts to MCV for an initial term of 25 years. CMS Midland Holdings Company ("CMS Holdings"), currently a wholly owned subsidiary of Consumers, acquired a 35% indirect equity interest in the Facility through its purchase of an interest in one of the Owner Trusts.

The Overall Lease Transaction requires MCV to achieve certain rent coverage ratios and other financial tests prior to a distribution to the Partners. Generally, these financial tests become more restrictive with the passage of time. Further, MCV is restricted to making permitted investments and incurring permitted indebtedness as specified in the Overall Lease Transaction. The Overall Lease Transaction also requires filing of certain periodic operating and financial reports, notification to the lessors of events constituting a material adverse change, significant litigation or governmental investigation, and change in status as a qualifying facility under FERC proceedings or court decisions, among others. Notification and approval is required for plant modification, new business activities, and other significant changes, as defined. In addition, MCV has agreed to indemnify various parties to the sale and leaseback transaction against any expenses or environmental claims asserted, or certain federal and state taxes imposed on the Facility, as defined in the Overall Lease Transaction.

Under the terms of the Overall Lease Transaction and refinancing of the tax-exempt bonds, approximately $25.0 million of transaction costs were a liability of MCV and have been recorded as a deferred cost. Financing costs incurred with the issuance of debt are deferred and amortized using the interest method over the remaining portion of the 25-year lease term. Deferred financing costs of approximately $1.2 million, $1.4 million and $1.5 million were amortized in the years 2004, 2003 and 2002, respectively.

Interest and fees incurred related to long-term debt arrangements during 2004, 2003 and 2002 were $103.4 million, $111.9 million and $118.3 million, respectively.

Interest and fees paid during 2004, 2003 and 2002 were $108.6 million, $115.4 million and $122.1 million, respectively.

Minimum payments due under these long-term debt arrangements over the next five years are (in thousands):

| | Principal | Interest | Total |
|---|---|---|---|
| 2005 | $ 76,548 | $ 97,835 | $174,383 |
| 2006 | 63,459 | 92,515 | 155,974 |
| 2007 | 62,916 | 87,988 | 150,904 |
| 2008 | 67,753 | 83,163 | 150,916 |
| 2009 | 70,335 | 76,755 | 147,090 |
| | $341,011 | $438,256 | $779,267 |

*Revolving Credit Agreement*

MCV has also entered into a working capital line ("Working Capital Facility"), which expires August 27, 2005. Under the terms of the existing agreement, MCV can borrow up to the $50.0 million commitment, in the form of short-term borrowings or letters of credit collateralized by MCV's natural gas inventory and earned receivables. At any given time, borrowings and letters of credit are limited by the amount of the borrowing base, defined as 90% of earned receivables and 50% of natural gas inventory, capped at $15 million. MCV did not utilize the Working Capital Facility during the year 2004, except for letters of credit associated with normal business practices. At December 31, 2004, MCV had $47.6 million available under its Working Capital Facility. As of December 31, 2004, MCV's borrowing base was capped at the maximum amount available of $50.0 million and MCV had outstanding letters of credit in the amount of $2.4 million. MCV believes that amounts available to it under the Working Capital Facility along with available cash reserves will be sufficient to meet any working capital shortfalls that might occur in the near term.

*Intercreditor Agreement*

MCV has also entered into an Intercreditor Agreement with the Owner Trustee, Working Capital Lender, U.S. Bank National Association as Collateral Agent ("Collateral Agent") and the Senior and Subordinated Indenture Trustees. Under the terms of this agreement, MCV is required to deposit all revenues derived from the operation of the Facility with the Collateral Agent for purposes of paying operating expenses and rent. In addition, these funds are required to pay construction modification costs and to secure future rent payments. As of December 31, 2004, MCV has deposited $138.2 million into the reserve account. The reserve account is to be maintained at not less than $40 million nor more than $137 million (or debt portion of next succeeding basic rent payment, whichever is greater). Excess funds in the reserve account are periodically transferred to MCV. This agreement also contains provisions governing the distribution of revenues and rents due under the Overall Lease Transaction, and establishes the priority of payment among the Owner Trusts, creditors of the Owner Trusts, creditors of MCV and the Partnership.

### (7) Commitments and Other Agreements

MCV has entered into numerous commitments and other agreements related to the Facility. Principal agreements are summarized as follows:

*Power Purchase Agreement*

MCV and Consumers have executed the PPA for the sale to Consumers of a minimum amount of electricity, subject to the capacity requirements of Dow and any other permissible electricity purchasers. Consumers has the right to terminate and/or withhold payment under the PPA if the Facility fails to achieve certain operating levels or if MCV fails to provide adequate fuel assurances. In the event of early termination of the PPA, MCV would have a maximum liability of approximately $270 million if the PPA were terminated in the 12th through 24th years. The term of this agreement is 35 years from the commercial operation date and year-to-year thereafter.

*Steam and Electric Power Agreement*

MCV and Dow executed the SEPA for the sale to Dow of certain minimum amounts of steam and electricity for Dow's facilities.

If the SEPA is terminated, and Consumers does not fulfill MCV's commitments as provided in the Backup Steam and Electric Power Agreement, MCV will be required to pay Dow a termination fee, calculated at that time, ranging from a minimum of $60 million to a maximum of $85 million. This agreement provides for the sale to Dow of steam and electricity produced by the Facility for terms of 25 years and 15 years, respectively, commencing on the commercial operation date and year-to-year thereafter.

*Steam Purchase Agreement*

MCV and DCC executed the SPA for the sale to DCC of certain minimum amounts of steam for use at the DCC Midland site. Steam sales under the SPA commenced in July 1996. Termination of this agreement, prior to expiration, requires the terminating party to pay to the other party a percentage of future revenues, which would have been realized had the initial term of 15 years been fulfilled. The percentage of future revenues payable is 50% if termination occurs prior to the fifth anniversary of the commercial operation date and 33$^{1}/_{3}$% if termination occurs after the fifth anniversary of this agreement. The term of this agreement is 15 years from the commercial operation date of steam deliveries under the contract and year-to-year thereafter.

*Gas Supply Agreements*

MCV has entered into gas purchase agreements with various producers for the supply of natural gas. The current contracted volume totals 238,531 MMBtu per day annual average for 2005. As of January 1, 2005, gas contracts with U.S. suppliers provide for the purchase of 173,336 MMBtu per day while gas contracts with Canadian suppliers provide for the purchase of 65,195 MMBtu per day. Some of these contracts require MCV to pay for a minimum amount of natural gas per year, whether or not taken. The estimated minimum commitments under these contracts based on current long term prices for gas for the years 2005 through 2009 are $384.6 million, $402.1 million, $436.7 million, $358.8 million and $324.0 million, respectively. A portion of these payments may be utilized in future years to offset the cost of quantities of natural gas taken above the minimum amounts.

*Gas Transportation Agreements*

MCV has entered into firm natural gas transportation agreements with various pipeline companies. These agreements require MCV to pay certain reservation charges in order to reserve the transportation capacity.

MCV incurred reservation charges in 2004, 2003 and 2002, of $35.5 million, $34.8 million and $35.1 million, respectively. The estimated minimum reservation charges required under these agreements for each of the years 2005 through 2009 are $34.3 million, $30.0 million, $21.6 million, $21.6 million and $21.6 million, respectively. These projections are based on current commitments.

*Gas Turbine Service Agreements*

Under a Service Agreement, as amended, with Alstom, which commenced on January 1, 1990 and was set to expire upon the earlier of the completion of the sixth series of major GTG inspections or December 31, 2009, Alstom sold MCV an initial inventory of spare parts for the GTGs and provided qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV's request. The Service Agreement was terminated for cause by MCV in February 2004. Alstom disputed MCV's right to terminate for cause. The parties settled the dispute and the agreement terminated in February 2004.MCV has a maintenance service and parts agreement with General Electric International, Inc. ("GEII"), which commenced July 1, 2004 ("GEII Agreement"). GEII will provide maintenance services and hot gas path parts for MCV's twelve GTGs, including providing an initial inventory of spare parts for the GTGs and providing qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV's request. Under terms and conditions similar to the MCV/Alstom Service Agreement, as described above the GEII Agreement will cover four rounds of major GTG inspections, which are expected to be completed by the year 2015, at a savings to MCV as compared to the Service Agreement with Alstom. MCV is to make monthly payments over the life of the contract totaling approximately $207 million (subject to escalations based on defined indices. The GEII Agreement can be terminated by either party for cause or convenience. Should termination for convenience occur, a buy out amount will be paid by the terminating party with payments ranging from approximately $19.0 million to $.9 million, based upon the number of operating hours utilized since commencement of the GEII Agreement.

*Steam Turbine Service Agreement*

MCV entered into a nine year Steam Turbine Maintenance Agreement with General Electric Company effective January 1, 1995, which is designed to improve unit reliability, increase availability and minimize unanticipated maintenance costs. In addition, this contract includes performance incentives and penalties, which are based on the length of each scheduled outage and the number of forced outages during a calendar year. Effective February 1, 2004, MCV and GE amended this contract to extend its term through August 31, 2007. MCV will continue making monthly payments over the life of the contract, which will total $22.3 million (subject to escalation based on defined indices). The parties have certain termination rights without incurring penalties or damages for such termination. Upon termination, MCV is only liable for payment of services rendered or parts provided prior to termination.

*Site Lease*

In December 1987, MCV leased the land on which the Facility is located from Consumers ("Site Lease"). MCV and Consumers amended and restated the Site Lease to reflect the creation of five separate undivided interests in the Site Lease as of June 1, 1990. Pursuant to the Overall Lease Transaction, MCV assigned these undivided interests in the Site Lease to the Owner Trustees, which in turn subleased the undivided interests back to MCV under five separate site subleases.

The Site Lease is for a term which commenced on December 29, 1987, and ends on December 31, 2035, including two renewal options of five years each. The rental under the Site Lease is $.6 million per annum, including the two five-year renewal terms.

**(8) Contingencies**

*Property Taxes*

In 1997, MCV filed a property tax appeal against the City of Midland at the Michigan Tax Tribunal contesting MCV's 1997 property taxes. Subsequently, MCV filed appeals contesting its property taxes for tax years 1998 through 2004 at the Michigan Tax Tribunal. A trial was held for tax years 1997-2000. The appeals for tax years 2001-2004 are being held in abeyance. On January 23, 2004, the Michigan Tax Tribunal issued its decision in MCV's tax appeal against the City of Midland for tax years 1997 through 2000 and has issued several orders correcting errors in the initial decision (together the "MTT Decision"). MCV management has estimated that the MTT Decision will result in a refund to MCV for the tax years 1997 through 2000 of at least approximately $35.3 million in taxes plus $9.6 million of interest as of December 31, 2004. The MTT Decision has been appealed to the Michigan Appellate Court by the City of Midland. MCV has filed a cross-appeal at the Michigan Appellate Court. MCV management cannot predict the outcome of these legal proceedings. MCV has not recognized any of the above stated refunds (net of approximately $16.1 million of deferred expenses) in earnings at this time.

*NOx Allowances*

The United States Environmental Protection Agency ("US EPA") has approved the State of Michigan's — State Implementation Plan ("SIP"), which includes an interstate NOx budget and allowance trading program administered by the US EPA beginning in 2004. Each NOx allowance permits a source to emit one ton of NOx during the seasonal control period, which for 2004 was from May 31 through September 30. NOx allowances may be bought or sold and unused allowances may be "banked" for future use, with certain limitations. MCV estimates that it will have excess NOx allowances to sell under this program. Consumers has given notice to MCV that it believes the ownership of the NOx allowances under this program belong, at least in part, to Consumers. MCV has initiated the dispute resolution process pursuant to the PPA to resolve this issue and the parties have entered into a standstill agreement deferring the resolution of this dispute. However, either party may terminate the standstill agreement at any time and reinstate the PPA's dispute resolution provisions. MCV management cannot predict the outcome of this issue. As of December 31, 2004, MCV has sold 1,200 tons of 2004 allowances for $2.7 million, which is recorded in "Accounts payable and accrued liabilities", pending resolution of ownership of these credits.

*Environmental Issues*

On July 12, 2004 the Michigan Department of Environmental Quality ("DEQ"), Air Quality Division, issued MCV a "Letter of Violation" asserting that MCV violated its Air Use Permit to Install No. 209-02 ("PTI") by exceeding the carbon monoxide emission limit on the Unit 14 GTG duct burner and failing to maintain certain records in the required format. On July 13, 2004 the DEQ, Water Division, issued MCV a "Notice Letter" asserting MCV violated its National Pollutant Discharge Elimination System Permit by discharging heated process waste water into the storm water system, failure to document inspections, and other minor infractions ("alleged NPDES violations").

MCV has declared all duct burners as unavailable for operational use (which reduces the generation capability of the Facility by approximately 100 MW) and is assessing the duct burner issue and has begun other corrective action to address the DEQ's assertions. MCV disagrees with certain of the DEQ's assertions. MCV filed responses to these DEQ letters in July and August 2004. On December 13, 2004, the DEQ informed MCV that it was pursuing an escalated enforcement action against MCV regarding the alleged violations of MCV's PTI. The DEQ also stated that the alleged violations are deemed federally significant and, as such, placed MCV on the United States Environmental Protection Agency's High Priority Violators List ("HPVL"). The DEQ and MCV are pursuing voluntary settlement of this matter, which will satisfy state and federal requirements and remove MCV from the HPVL. Any such settlement is likely to involve a fine, but the DEQ has not, at this time, stated what, if any, fine they will seek to impose. At this time, MCV management cannot predict the financial impact or outcome of these issues, however, MCV believes it has resolved all issues associated with the alleged NPDES violations and does not expect any further MDEQ actions on this NPDES matter.

### (9) Voluntary Severance Program

In July 2004, MCV announced a Voluntary Severance Program ("VSP") for all employees (union and non-union employees), subject to certain eligibility requirements. The VSP entitled participating employees, upon termination, to a lump sum payment, based upon number of years of service up to a maximum of 52 weeks of wages. Nineteen employees elected to participate in the VSP and MCV has recorded $1.7 million of severance costs in "Operating Expenses" related to the nineteen employees.

### (10) Retirement Benefits

*Postretirement Health Care Plans*

In 1992, MCV established defined cost postretirement health care plans ("Plans") that cover all full-time employees, excluding key management. The Plans provide health care credits, which can be utilized to purchase medical plan coverage and pay qualified health care expenses. Participants become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The Plans granted retroactive benefits for all employees hired prior to January 1, 1992. This prior service cost has been amortized to expense over a five-year period. MCV annually funds the current year service and interest cost as well as amortization of prior service cost to both qualified and non-qualified trusts. The MCV accounts for retiree medical benefits in accordance with SFAS 106, "Employers Accounting for Postretirement Benefits Other Than Pensions." This standard required the full accrual of such costs during the years that the employee renders service to the MCV until the date of full eligibility. The accumulated benefit obligation of the Plans were $4.9 million at December 31, 2004 and $3.3 million at December 31, 2003. The measurement date of these Plans was December 31, 2004.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was signed into law in December 2003. The Act expanded Medicare to include, for the first time, coverage for prescription drugs. At December 31, 2003, based upon FASB staff position, SFAS No. 106-1, "Employers Accounting for Postretirement Benefits Other Than Pensions," MCV had elected to defer financial recognition of this legislation until issuance of final accounting guidance. The final SFAS No. 106-2 was issued in second quarter 2004 and supersedes SFAS No. 106-1, which MCV adopted during this same period. The adoption of this standard had no impact to MCV's financial position because MCV does not consider its Plans to be actuarially equivalent. The Plans benefits provided to eligible participants are not annual or on-going in nature, but are a readily exhaustible, lump-sum amount available for use at the discretion of the participant.

The following table reconciles the change in the Plans' benefit obligation and change in Plan assets as reflected on the balance sheet as of December 31 (in thousands):

| | 2004 | 2003 |
|---|---|---|
| Change in benefit obligation: | | |
| Benefit obligation at beginning of year | $ 3,276.0 | $2,741.9 |
| Service cost | 232.1 | 212.5 |
| Interest cost | 174.8 | 178.2 |
| Actuarial gain (loss) | 1,298.0 | 147.4 |
| Benefits paid during year | (8.3) | (4.0) |
| Benefit obligation at end of year | 4,972.6 | 3,276.0 |
| Change in Plan assets: | | |
| Fair value of Plan assets at beginning of year | 2,826.8 | 2,045.8 |
| Actual return on Plan assets | 292.7 | 527.5 |
| Employer contribution | 206.5 | 257.5 |
| Benefits paid during year | (8.3) | (4.0) |
| Fair value of Plan assets at end of year | 3,317.7 | 2,826.8 |
| Unfunded (funded) status | 1,654.9 | 449.2 |
| Unrecognized prior service cost | (155.9) | (170.3) |
| Unrecognized net gain (loss) | (1,499.0) | (278.9) |
| Accrued benefit cost | $ — | $ — |

Net periodic postretirement health care cost for years ending December 31, included the following components (in thousands):

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Components of net periodic benefit cost: | | | |
| Service cost | $ 232.1 | $ 212.5 | $ 197.3 |
| Interest cost | 174.8 | 178.2 | 188.7 |
| Expected return on Plan assets | (216.1) | (163.7) | (167.0) |
| Amortization of unrecognized net (gain) or loss | 15.7 | 30.5 | 14.3 |
| Net periodic benefit cost | $ 206.5 | $ 257.5 | $ 233.3 |

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

| | 1-Percentage-Point Increase | 1-Percentage Point Decrease |
|---|---|---|
| Effect on total of service and interest cost components | $ 51.6 | $ 44.7 |
| Effect on postretirement benefit obligation | $514.8 | $447.1 |

Assumptions used in accounting for the Post-Retirement Health Care Plan were as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Discount rate | 5.75% | 6.00% | 6.75% |
| Long-term rate of return on Plan assets | 8.00% | 8.00% | 8.00% |
| Inflation benefit amount | | | |
| 1998 through 2004 | 0.00% | 0.00% | 0.00% |
| 2005 and later years | 5.00% | 4.00% | 4.00% |

The long-term rate of return on Plan assets is established based on MCV's expectations of asset returns for the investment mix in its Plan (with some reliance on historical asset returns for the Plans). The expected returns for various asset categories are blended to derive one long-term assumption.

*Plan Assets.* Citizens Bank has been appointed as trustee ("Trustee") of the Plan. The Trustee serves as investment consultant, with the responsibility of providing financial information and general guidance to the MCV Benefits Committee. The Trustee shall invest the assets of the Plan in the separate investment options in accordance with instructions communicated to the Trustee from time to time by the MCV Benefit Committee. The MCV Benefits Committee has the fiduciary and investment selection responsibility for the Plan. The MCV Benefits Committee consists of MCV Officers (excluding the President and Chief Executive Officer).

The MCV has a target allocation of 80% equities and 20% debt instruments. These investments emphasis total growth return, with a moderate risk level. The MCV Benefits Committee reviews the performance of the Plan investments quarterly, based on a long-term investment horizon and applicable benchmarks, with rebalancing of the investment portfolio, at the discretion of the MCV Benefits Committee.

MCV's Plan's weighted-average asset allocations, by asset category are as follows as of December 31:

| | 2004 | 2003 |
|---|---|---|
| Asset Category: | | |
| Cash and cash equivalents | 1% | 11% |
| Fixed income | 19% | 17% |
| Equity securities | 80% | 72% |
| Total | 100% | 100% |

*Contributions.* MCV expects to contribute approximately $.4 million to the Plan in 2005.

*Retirement and Savings Plans*

MCV sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, MCV makes contributions to the plan of either five or ten percent of an employee's eligible annual compensation dependent upon the employee's age. MCV also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee's savings up to a maximum level. In 2004, 2003 and 2002, MCV contributed $1.4 million, $1.3 million and $1.2 million, respectively under these plans.

*Supplemental Retirement Benefits*

MCV provides supplemental retirement, postretirement health care and excess benefit plans for key management. These plans are not qualified plans under the Internal Revenue Code; therefore, earnings of the trusts maintained by MCV to fund these plans are taxable to the Partners and trust assets are included in the assets of MCV.

### (11) Partners' Equity and Related Party Transactions

The following table summarizes the nature and amount of each of MCV's Partner's equity interest, interest in profits and losses of MCV at December 31, 2004, and the nature and amount of related party transactions or agreements that existed with the Partners or affiliates as of December 31, 2004, 2003 and 2002, and for each of the twelve month periods ended December 31 (in thousands).

| Beneficial Owner, Equity Partner, Type of Partner and Nature of Related Party | Equity Interest | Interest | Related Party Transactions and Agreements | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|---|
| CMS Energy Company | | | | | | |
| CMS Midland, Inc. | $396,888 | 49.0% | Power purchase agreements | $601,535 | $513,774 | $557,149 |
| General Partner; wholly-owned subsidiary of Consumers Energy Company | | | Purchases under gas transportation agreements | 9,349 | 14,294 | 23,552 |
| | | | Purchases under spot gas agreements | — | 663 | 3,631 |
| | | | Purchases under gas supply agreements | — | 2,330 | 11,306 |
| | | | Gas storage agreement | 2,563 | 2,563 | 2,563 |
| | | | Land lease/easement agreements | 600 | 600 | 600 |
| | | | Accounts receivable | 50,364 | 40,373 | 44,289 |
| | | | Accounts payable | 1,031 | 1,025 | 3,502 |
| | | | Sales under spot gas agreements | — | 3,260 | 1,084 |
| El Paso Corporation | $141,397 | 18.1% | | | | |
| Source Midland Limited Partnership ("SMLP") General Partner; owned by subsidiaries of El Paso Corporation | | | Purchase under gas transportation agreements | 12,334 | 13,023 | 12,463 |
| | | | Purchases under spot gas agreement | — | 610 | 15,655 |
| | | | Purchases under gas supply agreement | 70,000 | 54,308 | 47,136 |
| | | | Gas agency agreement | 264 | 238 | 365 |
| | | | Deferred reservation charges under gas purchase agreement | 3,152 | 4,728 | — |
| | | | Accounts receivable | — | — | 523 |
| | | | Accounts payable | 10,997 | 5,751 | 7,706 |
| | | | Sales under spot gas agreements | — | 3,474 | 14,007 |
| El Paso Midland, Inc. ("El Paso Midland") General Partner; wholly-owned subsidiary of El Paso Corporation | 84,838 | 10.9 | See related party activity listed under SMLP. | | | |
| MEI Limited Partnership ("MEI") A General and Limited Partner; 50% interest owned by El Paso Midland, Inc. and 50% interest owned by SMLP | | | See related party activity listed under SMLP. | | | |
| General Partnership Interest | 70,701 | 9.1 | | | | |
| Limited Partnership Interest | 7,068 | .9 | | | | |
| Micogen Limited Partnership ("MLP") Limited Partner, owned subsidiaries of El Paso Corporation | 35,348 | 4.5 | See related party activity listed under SMLP. | | | |
| Total El Paso Corporation | $339,352 | 43.5% | | | | |
| The Dow Chemical Company | | | | | | |
| The Dow Chemical Company | $ 73,735 | 7.5% | Steam and electric power agreement | 39,055 | 36,207 | 29,385 |
| Limited Partner | | | Steam purchase agreement — Dow Corning Corp (affiliate) | 4,289 | 4,017 | 3,746 |
| | | | Purchases under demineralized water supply agreement | 8,142 | 6,396 | 6,605 |
| | | | Accounts receivable | 4,003 | 3,431 | 3,635 |
| | | | Accounts payable | 744 | 610 | 1,016 |
| | | | Standby and backup fees | 766 | 731 | 734 |
| | | | Sales of gas under tolling agreement | — | — | 6,442 |
| Alanna Corporation | | | | | | |
| Alanna Corporation | $ 1(1) | .00001% | Note receivable | 1 | 1 | 1 |
| Limited Partner; wholly-owned subsidiary of Alanna Holdings Corporation | | | | | | |

## Footnotes to Partners' Equity and Related Party Transactions

(1) Alanna's capital stock is pledged to secure MCV's obligation under the lease and other overall lease transaction documents.

## EL PASO CORPORATION

## EXHIBIT LIST
**December 31, 2004**

Each exhibit identified below is filed as part of this report. Exhibits not incorporated by reference to a prior filing or previously filed are designated by an "*"; exhibits previously filed with our Annual Report on Form 10-K for the fiscal year ended December 31, 2004 are designated by an "**"; 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.

| | |
|---|---|
| 2.A | Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (including the form of Assumption Agreement to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.1 to our Form 8-K filed December 15, 2003) |
| 2.B | Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the form of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, to be entered into in connection with the merger, attached as an exhibit thereto) (Exhibit 2.2 to our Form 8-K filed December 15, 2003); Amendment No. 1 to Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company, dated as of April 19, 2004 (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (Exhibit 2.1 to our Form 8-K filed April 21, 2004); Second Amended and Restated Limited Liability Company Agreement of GulfTerra Energy Company, L.L.C., adopted by GulfTerra GP Holding Company, a Delaware corporation, and Enterprise Products GTM, LLC, a Delaware limited liability company, as of December 15, 2003 (Exhibit 2.3 to our Form 8-K filed December 15, 2003); Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (Exhibit 2.4 to our Form 8-K filed December 15, 2003) |
| **2.B.1 | Purchase and Sale Agreement, dated as of January 14, 2005, by and among Enterprise GP Holdings, L.P., Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso Corporation and GulfTerra GP Holding Company |
| 3.A | Restated Certificate of Incorporation effective as of August 11, 2003 (Exhibit 3.A to our 2003 Second Quarter Form 10-Q) |
| 3.B | By-Laws effective as of July 31, 2003 (Exhibit 3.B to our 2003 Second Quarter Form 10-Q) |
| **4.A | Indenture dated as of May 10, 1999, by and between El Paso and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee |

10.A Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors, as defined therein, in favor of JPMorgan Chase Bank, N.A., as collateral agent (Exhibit 10.C to our Form 8-K filed November 29, 2004); Amended and Restated Parent Guarantee Agreement dated as of November 23, 2004, made by El Paso Corporation, in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.D to our Form 8-K filed November 29, 2004)

10.B Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004)

10.C $3,000,000,00 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (Exhibit 99.1 to our Form 8-K filed April 18, 2003); First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 17, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lender and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 Form 10-K); Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Form 10-K); Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 99.B to our Form 8-K filed August 10, 2004)

10.D $1,000,000,000 Amended and Restated 3-Year Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, The Lenders Party Thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A., as Syndication Agent, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.2 to our Form 8-K filed April 18, 2003)

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| 10.E | Security and Intercreditor Agreement dated as of April 16, 2003 Among El Paso Corporation, the Persons Referred to therein as Pipeline Company Borrowers, the Persons Referred to therein as Grantors, Each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to our Form 8-K filed April 18, 2003) |
| +10.F | 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our 2003 Form 10-K) |
| **+10.G | Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 |
| **+10.G.1 | Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors |
| +10.G.2 | Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 2001 First Quarter Form 10-Q) |
| +10.H | 2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our 2001 Form 10-K); Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.H.1 to our 2003 Form 10-K) |
| **+10.I | 1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 |
| **+10.I.1 | Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan |
| **+10.I.2 | Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan |
| +10.J | 1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.1 to our Form S-8 filed May 20, 1999); Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.V.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.I.1 to our 2003 Second Quarter Form 10-Q) |
| +10.K | 2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.1 to our Form S-8 filed June 29, 2001); Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2001 Form 10-K); Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Form 10-K); Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2002 Second Quarter Form 10-Q); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.J.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.K.1 to our 2003 Form 10-K) |
| +10.L | Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.K to our 2001 Form 10-K); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.K.1 to our 2002 Form 10-K); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our 2004 Third Quarter Form 10-Q) |
| **+10.L.1 | Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan |
| **+10.M | Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 |
| +10.M.1 | Amendment No. 1 effective as of February 7, 2001 to the Senior Executive Survivor Benefit Plan (Exhibit 10.I.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.L.1 to our 2002 Form 10-K) |

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| **+10.N | Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 |
| +10.N.1 | Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.K.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2002 Form 10-K); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan (Exhibit 10.N.1 to our 2003 Third Quarter Form 10-Q) |
| +10.O | 2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our 2003 Form 10-K) |
| **+10.P | Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 |
| +10.P.1 | Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.L.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our 2003 Form 10-K) |
| +10.Q | Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed January 14, 2000); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.M.1 to our 2001 First Quarter Form 10-Q); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan; Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan and Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exhibit 10.P.1 to our 2002 Form 10-K) |
| **+10.R | Domestic Relocation Policy effective November 1, 1996 |
| **+10.S | Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 |
| +10.S.1 | Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q) |
| +10.T | Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed December 18, 2000); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.U.1 to our 2001 First Quarter Form 10-Q); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.1 to our Form S-8 filed February 11, 2002); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.T.1 to our 2002 Form 10-K) |
| +10.U | El Paso Production Companies Long-Term Incentive Plan effective as of January 1, 2003 (Exhibit 10.AA to our 2003 First Quarter Form 10-Q); Amendment No. 1 effective as of June 6, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.AA.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan (Exhibit 10.V.1 to our 2003 Form 10-K) |

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| +10.V | Severance Pay Plan Amended and Restated effective as of October 1, 2002; Supplement No. 1 to the Severance Pay Plan effective as of January 1, 2003; and Amendment No. 1 to Supplement No. 1 effective as of March 21, 2003 (Exhibit 10.Z to our 2003 First Quarter Form 10-Q); Amendment No. 2 to Supplement No. 1 effective as of June 1, 2003 (Exhibit 10.Z.1 to our 2003 Second Quarter Form 10-Q); Amendment No. 3 to Supplement No. 1 effective as of September 2, 2003 (Exhibit 10.Z.1 to our 2003 Third Quarter Form 10-Q); Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003 (Exhibit 10.W.1 to our 2003 Form 10-K); Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004 (Exhibit 10.W.1 to our 2003 Form 10-K) |
| +10.W | Employment Agreement Amended and Restated effective as of February 1, 2001 between El Paso and William A. Wise (Exhibit 10.0 to our 2000 Form 10-K) |
| +10.X | Letter Agreement dated September 22, 2000 between El Paso and D. Dwight Scott (Exhibit 10.W to our 2002 Third Quarter Form 10-Q) |
| +10.X.1 | Letter Agreement dated July 16, 2004 between El Paso Corporation and D. Dwight Scott. (Exhibit 10.VV to our 2003 Third Quarter Form 10-Q) |
| +10.Y | Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.U to our 2003 Third Quarter Form 10-Q) |
| +10.Y.1 | Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee (Exhibit 10.BB.1 to our 2003 Form 10-K) |
| +10.Z | Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart (Exhibit 10.CC to our 2003 Form 10-K) |
| +10.AA | Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later (Exhibit 10.FF to our 2002 Form 10-K) |
| +10.BB | Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective December 17, 2004 (Exhibit 10.WW to our 2003 Third Quarter Form 10-Q) |
| +10.CC | Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our 2003 Third Quarter Form 10-Q) |
| 10.DD | Master Settlement Agreement dated as of June 24, 2003, by and between, on the one hand, El Paso Corporation, El Paso Natural Gas Company, and El Paso Merchant Energy, L.P.; and, on the other hand, the Attorney General of the State of California, the Governor of the State of California, the California Public Utilities Commission, the California Department of Water Resources, the California Energy Oversight Board, the Attorney General of the State of Washington, the Attorney General of the State of Oregon, the Attorney General of the State of Nevada, Pacific Gas & Electric Company, Southern California Edison Company, the City of Los Angeles, the City of Long Beach, and classes consisting of all individuals and entities in California that purchased natural gas and/or electricity for use and not for resale or generation of electricity for the purpose of resale, between September 1, 1996 and March 20, 2003, inclusive, represented by class representatives Continental Forge Company, Andrew Berg, Andrea Berg, Gerald J. Marcil, United Church Retirement Homes of Long Beach, Inc., doing business as Plymouth West, Long Beach Brethren Manor, Robert Lamond, Douglas Welch, Valerie Welch, William Patrick Bower, Thomas L. French, Frank Stella, Kathleen Stella, John Clement Molony, SierraPine, Ltd., John Frazee and Jennifer Frazee, John W.H.K. Phillip, and Cruz Bustamante (Exhibit 10.HH to our 2003 Second Quarter Form 10-Q) |

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| 10.EE | Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our 2003 Form 10-K) |
| 10.FF | Joint Settlement Agreement submitted and entered into by El Paso Natural Gas Company, El Paso Merchant Energy Company, El Paso Merchant Energy-Gas, L.P., the Public Utilities Commission of the State of California, Pacific Gas & Electric Company, Southern California Edison Company and the City of Los Angeles (Exhibit 10.II to our 2003 Second Quarter Form 10-Q) |
| 10.GG | Swap Settlement Agreement dated effective as of August 16, 2004, among the Company, El Paso Merchant Energy, L.P., East Coast Power Holding Company L.L.C. and ECTMI Trutta Holdings LP (Exhibit 10.A to our Form 8-K filed October 15, 2004, and terminated as described in our Form 8-K filed December 3, 2004) |
| **21 | Subsidiaries of El Paso |
| *23.A | Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Houston) |
| **23.B | Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (Detroit) |
| **23.C | Consent of Ryder Scott Company, L.P. |
| *31.A | Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002 |
| *31.B | Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002 |
| *32.A | Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002 |
| *32.B | Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002 |

**Undertaking**

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

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 8th day of April 2005.

EL PASO CORPORATION
Registrant

By /s/ DOUGLAS L. FOSHEE
Douglas L. Foshee
*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 Corporation and in the capacities and on the dates indicated:

| Signature | Title | Date |
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| /s/ DOUGLAS L. FOSHEE<br>(Douglas L. Foshee) | President, Chief Executive Officer and Director<br>(Principal Executive Officer) | April 8, 2005 |
| /s/ D. DWIGHT SCOTT<br>(D. Dwight Scott) | Executive Vice President and Chief Financial Officer<br>(Principal Financial Officer) | April 8, 2005 |
| /s/ JEFFREY I. BEASON<br>(Jeffrey I. Beason) | Senior Vice President and Controller<br>(Principal Accounting Officer) | April 8, 2005 |
| /s/ RONALD L. KUEHN, JR.<br>(Ronald L. Kuehn, Jr.) | Chairman of the Board and Director | April 8, 2005 |
| /s/ JOHN M. BISSELL<br>(John M. Bissell) | Director | April 8, 2005 |
| /s/ JUAN CARLOS BRANIFF<br>(Juan Carlos Braniff) | Director | April 8, 2005 |
| /s/ JAMES L. DUNLAP<br>(James L. Dunlap) | Director | April 8, 2005 |
| /s/ ROBERT W. GOLDMAN<br>(Robert W. Goldman) | Director | April 8, 2005 |
| /s/ ANTHONY W. HALL, JR.<br>(Anthony W. Hall, Jr.) | Director | April 8, 2005 |

| Signature | Title | Date |
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| /s/ THOMAS R. HIX<br>(Thomas R. Hix) | Director | April 8, 2005 |
| /s/ WILLIAM H. JOYCE<br>(William H. Joyce) | Director | April 8, 2005 |
| /s/ J. MICHAEL TALBERT<br>(J. Michael Talbert) | Director | April 8, 2005 |
| /s/ JOHN L. WHITMIRE<br>(John L. Whitmire) | Director | April 8, 2005 |
| /s/ JOE B. WYATT<br>(Joe B. Wyatt) | Director | April 8, 2005 |