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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

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, 2003 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $4,838,867,717.

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 September 24, 2004: 643,441,738

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: None

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

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. Oil includes natural gas liquids unless otherwise specified. 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.

Restatement of Historical Financial Information

In February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. The results of this process indicated that a significant downward revision to our proved reserve estimates was needed. In August 2004, we also determined that we had not properly accounted for certain derivatives, primarily those associated with many of the historical hedges of our anticipated natural gas production. After investigations into the factors that caused these issues, we determined that a material portion of the downward reserve revisions should be reflected in historical periods and that the historical accounting for our production and certain other hedges should be corrected. Accordingly, we restated our historical financial information for the years from 1999 to 2002 and for the first nine months of 2003.

In the restatement for our reserve revisions, an investigation determined that certain personnel used aggressive, and at times, unsupportable methods to book proved reserves. In some instances, certain personnel provided historical proved reserve estimates that they knew or should have known were incorrect at the time they were reported. The investigation also found that we did not, in some cases, maintain adequate documentation and records to support historically booked proved natural gas reserves.

In the restatement for certain hedges, we determined that we had not properly applied generally accepted accounting principles for many of our production hedges, certain other hedge transactions related to pipeline capacity and hedges of the production owned by one of our pipeline subsidiaries. Most of these hedging transactions were entered into from 1999 to 2002 under Master International Swaps and Derivatives Association, or ISDA, swap agreements and the restatement involved transactions where we entered into an identical, offsetting trading position at the same time we entered into the hedge. In reaching the conclusion to restate, we concluded that the business purpose for the offsetting transactions was not alone sufficient to satisfy the standards for separate accounting treatment from the hedge transaction. Generally accepted accounting principles, or GAAP, requires that the objective of the two transactions is not one that could have been accomplished through a single, though less efficient, transaction. In addition, we considered two additional factors in reaching this conclusion. First, we determined that some of the offsetting transactions had not been completed at market prices. Second, we had originally concluded that there was separate economic substance in the hedge and the offsetting transactions, based on our view that there was credit risk associated with the separate enforcement of the transactions. Upon further review, we determined that there was insufficient credit risk associated with enforcing these transactions to support that original conclusion.

As a result of these conclusions, we restated our historical proved natural gas and oil reserve estimates, the financial information derived from those estimates, and financial information related to our historical accounting for certain hedges for the periods from 1999 through 2002, and for the first nine months of 2003. The total cumulative impact of the restatement was a reduction of our previously reported stockholders' equity as of September 30, 2003 of approximately $2.4 billion. Of this amount, approximately $1.7 billion related to the restatement of our historical reserve estimates and approximately $0.7 billion related to the restatement of our historical accounting for hedges. These restated amounts have been reflected only in this Annual Report on Form 10-K, and we did not revise our historically filed reports for the impacts of the restatements. Consequently, you should not rely on historical information contained in those prior filings since this filing replaces and revises those historically reported amounts.

For a further discussion of the impact of the restatements on our selected financial information, see Part II, Item 6, Selected Financial Data; for a more detailed discussion of the factors leading to the restatements, the restatement methods used and the financial impacts of the restatements, see Item 8, Financial Statements and Supplementary Data, Note 1; and for a discussion of control weaknesses that contributed to these issues and changes we have made or are in the process of making to our control procedures, see 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 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 and acquisitions as well as internal growth initiatives. By 2001, our operations extended from natural gas production to power generation, and included many new ventures and businesses, in addition to our traditional natural gas businesses. During this period, our total assets grew from approximately $7 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 the latter part of 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, requiring us to re-prioritize our businesses throughout 2002 and 2003. Over 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 these sales activities and the performance of our businesses during this time period, we have also experienced significant losses.

In 2003, we appointed a new chief executive officer. Following an assessment period by our executive management team, we publicly announced our 2003 Long-Range Plan (Long-Range Plan) in December 2003. This Long-Range Plan establishes the roadmap for the future direction and focus of our company. The Long-Range Plan, among other things:

- defines our core businesses;
- establishes timetables for debt reduction; and
- sets a timeline for exiting from non-core businesses and assets.

Business Segments

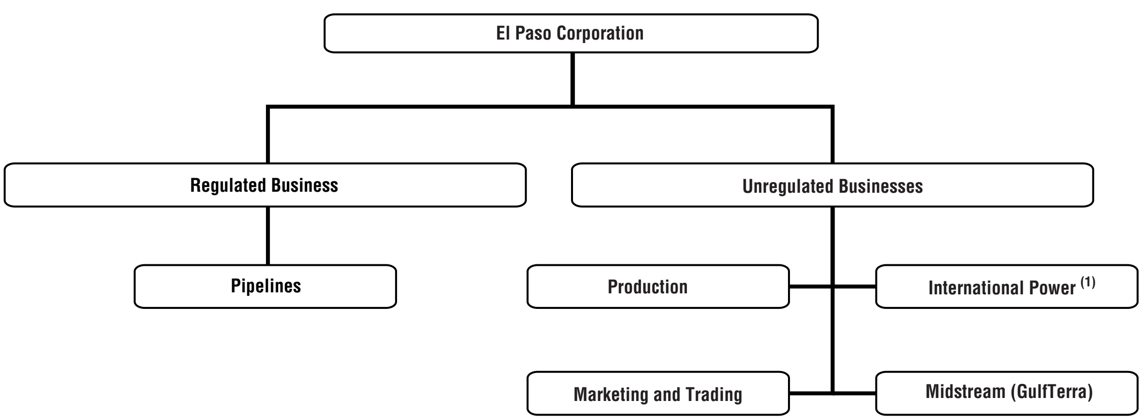
For the years ended December 31, 2003, we operated through four business segments — Pipelines, Production, Field Services and Merchant Energy. Through these segments, we provided the following energy related services:

Continuing Operations

Interstate Natural Gas Transmission and Storage	Our interstate pipeline system is the largest in the U.S., and owns or has interests in approximately 58,000 miles of pipeline and approximately 430 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.
Production	Our production business holds interests in approximately 8.1 million net developed and undeveloped acres and had over 2.6 Tcfe of proved natural gas and oil reserves worldwide at the end of 2003. During 2003, our production averaged approximately 1.1 Bcfe/d. During the first eight months of 2004, daily production averaged 855 MMcfe/d.

Midstream Services	Our midstream business owns a 50 percent interest in the general partner of a large publicly traded master limited partnership, GulfTerra Energy Partners, L.P. (GulfTerra), as well as a significant limited partner interest in GulfTerra. GulfTerra provides onshore and offshore midstream services to a diverse base of customers. Our midstream businesses also provide gathering and processing services, primarily in south Texas and south Louisiana. We sold a substantial portion of our limited and general partnership interests in GulfTerra and our south Texas gathering and processing assets in 2004.
Energy Marketing and Trading	Our energy marketing and trading business markets our natural gas and oil production and is managing and/or liquidating our historical energy trading portfolio.
Power Generation and Supply	Our power businesses own or manage almost 15,000 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. This business also manages power supply arrangements with electric utility customers to meet their peak electricity requirements. We have sold or expect to sell substantially all of our domestic power business in 2004.
	Discontinued Operations
Petroleum Markets	Our petroleum markets business owns and operates refineries in the northeastern U.S. and in Aruba, with a capacity to refine over 430,000 Bbls of oil per day. We completed the sale of substantially all of this business in early 2004.

Our Long-Range Plan did not impact our segment structure as of December 31, 2003, but will impact our reported segments going forward. Under our Long-Range Plan, we will provide natural gas and related energy products and services through two primary business lines: a regulated business line and an unregulated business line. Below is a chart that outlines the composition of those business lines:



(1) In the long-term, we intend to dispose of substantially all of our assets and investments in our international power business, except in Brazil.

Our long-term strategy will focus on:

Business	Objective and Strategy
Pipelines	Protecting and enhancing asset value through successful recontracting, continuous efficiency gains 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.
Midstream	Optimizing our remaining investment in GulfTerra and our remaining gathering and processing assets.
Marketing and Trading	Marketing and physical trading of our natural gas and oil production.
Power	Managing power generation assets to maximize value.

Below is a description of each of our existing business segments. Our current business segments of Pipelines, Production, Field Services and Merchant Energy are strategic business units that provide a variety of energy products and services. We managed each segment separately through the end of 2003 and into early 2004, and each segment requires different technology and marketing strategies. As we implement our Long-Range Plan, these segments will change to reflect the way our operations will be managed in the future. 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 26, which is incorporated herein by reference.

Regulated Business — Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage and related services and owns or has interests in approximately 58,000 miles of interstate natural gas pipelines in the U.S. and internationally. In the U.S., our systems connect the nation's principal natural gas supply regions to the six largest consuming regions in the U.S.: the Gulf Coast, California, the Northeast, the Midwest, the Southwest and the Southeast. These pipelines represent the largest integrated coast-to-coast mainline natural gas transmission system in the U.S. Our U.S. pipeline systems also own or have interests in approximately 430 Bcf of storage capacity used to provide a variety of flexible services to our customers and a liquefied natural gas (LNG) terminal at Elba Island, Georgia. Our international pipeline operations include access to systems in Canada and Mexico and until June 2004, interests in three operating natural gas transmission systems in Australia, two of which were sold in June 2004. The remaining Australian investment was placed into receivership in the second quarter of 2004.

Our Pipelines segment conducts its business activities primarily through seven wholly owned and five partially owned interstate transmission systems along with five underground natural gas storage entities and the entity that owns the Elba Island LNG terminalling facility. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

		As of December 31, 2003			Average Throughput(1)		
Transmission System	Supply and Market Region	Miles of Pipeline	Design Capacity	Storage Capacity	2003	2002	2001
			(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	6,937	90	4,710	4,596	4,405
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.	10,600	6,414	202	4,232	4,130	4,531

Transmission System	Supply and Market Region	As of December 31, 2003 Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2003	2002 (BBtu/d)	2001
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.	10,600	5,650[2]	—	3,874	3,799	4,253
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	3,296	60	2,101	2,151	2,027
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	3,100	29	1,685	1,687	1,569
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,880	—	1,213	1,194	1,017
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	—	192	266	283

(1) Includes throughput transported on behalf of affiliates.

(2) This capacity reflects winter-sustainable west-flow capacity (including 320 MMcf/d due to the completion of our Line 2000 compression added in 2004) and 800 MMcf/d of east-end delivery capacity.

We also have six pipeline expansion projects underway as of September 2004 that have been approved by the Federal Energy Regulatory Commission (FERC):

Transmission System	Project	Capacity	Description[(1)]	Anticipated Completion Date
		(MMcf/d)		
ANR	WestLeg Wisconsin expansion	218	To increase capacity of ANR's existing system by looping the Madison lateral line and by enlarging the Beloit lateral line through abandonment and replacement.	November 2004
	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 on the Denmark Lateral in Brown County, and modify ANR's existing Mountain Compressor Station in Oconto County, Wisconsin.	November 2005
	NorthLeg Wisconsin expansion	—	To add 6,000 horsepower of electric powered compression at ANR's Weyauwega Compressor station in Waupaca County, Wisconsin.	November 2005
SNG	South System II (Phase 2)	138	Installation of compression and pipeline looping to increase firm transportation capacity along SNG's south mainline to Alabama, Georgia and South Carolina.	August 2004[(2)]
CPG	Cheyenne Plains Gas Pipeline (CPG)	576	To construct a 36-inch pipeline to transport gas from the Cheyenne hub in Colorado to a hub near Greensburg, Kansas.	December 2004
	Cheyenne Plains expansion	176	To add approximately 10,300 horsepower of compression to the Cheyenne Plains project.	December 2005

(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 the transmission system's capacity.
(2) Placed in service in August 2004.

Partially Owned Interstate Transmission Systems

Transmission System[(1)]	Supply and Market Region	As of December 31, 2003 Ownership Interest	Miles of Pipeline	Design Capacity[(2)]	Average Throughput[(2)] 2003	2002	2001
		(Percent)		(MMcf/d)	(BBtu/d)		
Domestic							
Florida Gas Transmission[(3)]	Extends from south Texas to south Florida.	50	4,886	1,980	1,963	2,004	1,616
Great Lakes Gas Transmission	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,366	2,378	2,224
Portland Natural Gas Transmission[(4)]	Extends from the Canadian border near Pittsburg, New Hampshire to Dracut, Massachusetts.	—	—	—	130	144	123
International							
Dampier-to-Bunbury pipeline system[(5)]	Extends from Dampier to Bunbury in Western Australia.	33	1,152	570	584	573	555
Moomba-to-Adelaide pipeline system[(6)]	Extends from Moomba to Adelaide in South Australia.	33	685	383	238	271	261
Ballera-to-Wallumbilla pipeline system[(6)]	Extends from Ballera to Wallumbilla in Queensland, Australia.	33	470	115	73	72	71

(1) These systems are accounted for as equity investments.
(2) Volumes represent the systems' total design capacity and average throughput and are not adjusted for our ownership interest.
(3) We have an investment in Citrus Corporation, which owns this system.
(4) We sold our equity interest in the Portland Natural Gas Transmission System in the fourth quarter of 2003.

(5) Our investment in this system was placed in receivership in the second quarter of 2004.
(6) Our interests in these systems were sold in June 2004.

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

Underground Natural Gas Storage Entities

Storage Entity	As of December 31, 2003 Ownership Interest (Percent)	As of December 31, 2003 Storage Capacity[1] (Bcf)	Location
Bear Creek Storage	100	58	Louisiana
ANR Storage	100	56	Michigan
Blue Lake Gas Storage[2]	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, 2003.

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 capacity at the terminal was initially contracted with our affiliate, El Paso Merchant Energy L.P. (EPME), under a contract that extends through 2023. This contract was assigned by EPME to a subsidiary of British Gas, BG LNG Services, LLC in December 2003. 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 $159 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 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 systems or storage 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 2003, approximately 84 percent of our transportation services revenues were attributable to charges paid by firm customers. The remaining 16 percent of our transportation services revenues were attributable to usage charges paid by both firm and interruptible customers. Due to our regulated nature, our financial results have historically been relatively stable. However, these 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.

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 pipeline 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.

Other Matters Impacting Our Markets

Electric power generation is the fastest growing demand sector of the natural gas market. The potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation potentially benefit 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 and more effective use of surplus electric capacity as a result of open market access. In addition, in several regions of the country, new capacity additions have exceeded load growth and transmission capabilities out of those regions. This may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their creditworthiness.

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 and market areas. These LNG delivery systems also may compete with pipelines for transportation of gas into market areas.

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, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

The following table details the markets we serve and the competition on each of our wholly owned pipeline systems as of December 31, 2003:

Transmission System	Customer Information	Contract Information	Competition
TGP	Approximately 406 firm and interruptible customers Major Customers: None of which individually represents more than 10 percent of revenues	Approximately 481 firm contracts Contracted capacity: 87% 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.
ANR	Approximately 228 firm and interruptible customers Major Customer: We Energies (1,050 BBtu/d)	Approximately 537 firm contracts Contracted capacity: 97% Weighted average remaining contract term of approximately four years. Contract terms expire in 2004-2010.	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.
EPNG	Approximately 215 firm and interruptible customers Major Customer: Southern California Gas Company (1,243 BBtu/d) (95 BBtu/d)	Approximately 215 firm contracts Contracted capacity: 97% Weighted average remaining contract term of approximately five years[(1)]. Contract terms expire in 2006. Contract terms expire in 2004-2007.	EPNG faces competition in the West and Southwest from other existing pipelines, storage facilities and newly proposed pipeline and LNG projects as well as alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.

(1) Approximately 1,567 MMcf/d currently under contract is subject to early termination in August 2006 provided shippers give timely notice of an intent to terminate. If all of these rights were exercised, the weighted average on the remaining contract terms would decrease to approximately three years.

Transmission System	Customer Information	Contract Information	Competition
SNG	Approximately 270 firm and interruptible customers	Approximately 170 firm contracts Contracted capacity: 100% 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:		
	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 (425 BBtu/d)	Contract terms expire in 2005-2013.	
	Scana Corporation (251 BBtu/d)	Contract terms expire in 2005-2017.	
CIG	Approximately 130 firm and interruptible customers	Approximately 190 firm contracts Contracted capacity: 97% Weighted average remaining contract term of approximately five years.	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 and transport these volumes to markets in the West, Northwest, Southwest and Midwest.
	Major Customer:		
	Public Service Company of Colorado		
	(187 BBtu/d)	Contract term expires in 2005.	
	(970 BBtu/d)	Contract term expires in 2007.	
	(261 BBtu/d)	Contract terms expire in 2009-2014.	
WIC	Approximately 40 firm and interruptible customers	Approximately 50 firm contracts Contracted capacity: 98% Weighted average remaining contract term of approximately six years.	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.
	Major Customers:		
	Williams Power Company (303 BBtu/d)	Contract terms expire in 2008-2013.	
	Colorado Interstate Gas Company (247 BBtu/d)	Contract terms expire in 2004-2007.	
	Cantera Gas Company (243 BBtu/d)	Contract terms expire in 2004-2013.	
	Western Gas Resources (235 BBtu/d)	Contract terms expire in 2007-2013.	

Transmission System	Customer Information	Contract Information	Competition
MPC	Approximately 35 firm and interruptible customers	Eight firm contracts Contracted capacity: 96% Weighted average remaining contract term of approximately three years.	MPC faces competition from other existing pipelines, proposed LNG projects and alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
	Major Customers:		
	Texaco Natural Gas Inc. (185 BBtu/d)	Contract term expires in 2007.	
	Burlington Resources Trading Inc. (76 BBtu/d)	Contract term expires in 2007.	
	Los Angeles Department of Water and Power (50 BBtu/d)	Contract term expires in 2007.	

Unregulated Businesses — Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in North America. In the U.S., we controlled over 3 million net acres of leasehold acreage through our onshore and coal seam operations in 20 states, including New Mexico, Louisiana, Texas, Oklahoma, Alabama and Utah, and through our offshore operations in federal and state waters in the Gulf of Mexico. As of December 31, 2003, we have international exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey. During 2003, daily production averaged 1.1 Bcfe/d, and our proved natural gas and oil reserves at December 31, 2003, were approximately 2.6 Tcfe.

Our December 31, 2003 proved reserve estimates reflect a 1.8 Tcfe downward revision to our proved natural gas and oil reserves. Following an investigation into the factors that caused this significant revision, we determined that a material portion of these revisions should be reflected in prior years and, as a result, we restated our historical proved reserve estimates and our historical financial information derived from these proved reserve estimates. In August 2004, we also determined that we had not properly applied the accounting related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. Following an investigation into this matter, we concluded that our historical financial statements should be further restated. See Part II, Item 6, Selected Financial Data and Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of these restatements.

As part of our Long-Range Plan, our strategy in this segment will focus on developing production opportunities from our asset base in the U.S. and Brazil. We will continue to divest our non-core assets, including international properties in Canada, Hungary and Indonesia. As of September 2004, we have sold substantially all of our production operations in Canada and Indonesia.

In June 2004, we announced a back-to-basics plan for our business. This plan emphasizes strict capital discipline designed to improve capital efficiency through the use of standardized risk analysis, a heightened focus on cost control, and a rigorous process for booking proved natural gas and oil reserves. This back-to-basics approach is designed to stabilize production by improving the production mix across our operating areas, thereby generating more predictable income and cash flows in this business.

Our U.S. operations are divided into the following areas: onshore, offshore and coal seam. The onshore area includes operations in three regions: Texas Onshore, Central and Rocky Mountains. The Texas Onshore region includes our operations along the Texas Gulf Coast, the Central region includes primarily our operations in north Louisiana and the Rocky Mountain region includes our interests in Utah. The offshore area includes our interests in the Gulf of Mexico primarily in state and federal waters along the coast of Texas and Louisiana. Our coal seam area consists of operations in the Black Warrior Basin in Alabama, the Arkoma Basin in Oklahoma and the Raton Basin in New Mexico. In each of our domestic operating areas, we have extensive acreage and/or seismic holdings, which allow us to be competitive.

In Brazil, our operations are concentrated in the Camamu, Santos, and Potiguar Basins. We have been successful with our drilling programs in the Santos and Camamu Basins and are seeking a strategic partner with a strong interest in Brazil to contribute near-term development capital in these two basins. Through our UnoPaso Ltda., or UnoPaso, investment, in which we owned a 50 percent interest at December 31, 2003, we continue to work with Petrobras, the Brazilian national oil company, in growing our presence in the Potiguar Basin with increased production and planned exploratory activity. In July 2004, we acquired the remaining 50 percent interest in UnoPaso.

Natural Gas and Oil Reserves

The tables below provide information on our proved reserves at December 31, 2003. Reserve information in these tables is based on the reserve report dated January 1, 2004, prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates for 90 percent and 10 percent of our properties, respectively. The total estimate of proved reserves prepared independently by Ryder Scott Company and Huddleston & Co., Inc. was within five percent of our internally prepared estimates. 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. The tables below exclude reserve information related to our equity ownership interests in UnoPaso; the Merchant Energy segment's interests in Sengkang in Indonesia and Aguaytia in Peru; and the Field Services segment's interest in GulfTerra. Combined proved reserve balances for these equity investment interests were 255,278 MMcf of natural gas and 7,105 MBbls of oil or natural gas equivalents of 297,909 MMcfe, all net to our ownership interests. Our estimated proved reserves as of December 31, 2003, and our 2003 production, by area, are as follows:

	Net Proved Reserves[1]				
	Natural Gas	Liquids[2]	Total		2003 Production
	(MMcf)	(MBbls)	(MMcfe)	(Percent)	(MMcfe)
U.S.					
Onshore					
Texas Onshore	538,681	14,310	624,538	24	133,533
Central	342,932	3,314	362,816	14	64,423
Rocky Mountains	13,015	12,458	87,763	3	6,411
Total Onshore	894,628	30,082	1,075,117	41	204,367
Offshore	330,505	18,273	440,141	17	163,012
Coal Seam	836,206	1	836,214	32	42,053
Total U.S.	2,061,339	48,356	2,351,472	90	409,432
International					
Canada[3]	97,431	2,986	115,347	4	16,986
Hungary	4,401	—	4,401	—	401
Brazil	—	20,543	123,258	4	—
Indonesia[3]	30,520	1,742	40,972	2	—
Total International	132,352	25,271	283,978	10	17,387
Total	2,193,691	73,627	2,635,450	100	426,819

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

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

(3) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

The table below summarizes our estimated proved producing reserves, proved non-producing reserves, and proved undeveloped reserves by country as of December 31, 2003:

	Net Proved Reserves[1]			Relative Percentage
	Natural Gas (MMcf)	Liquids[2] (MBbls)	Total (MMcfe)	
U.S.				
Producing	1,185,046	25,588	1,338,570	57
Non-Producing	243,380	11,321	311,305	13
Undeveloped	632,913	11,447	701,597	30
Total proved	2,061,339	48,356	2,351,472	100
Canada[3]				
Producing	78,944	1,645	88,812	77
Non-Producing	7,835	64	8,218	7
Undeveloped	10,652	1,277	18,317	16
Total proved	97,431	2,986	115,347	100
Brazil				
Undeveloped	—	20,543	123,258	100
Total proved	—	20,543	123,258	100
Other Countries[3][4]				
Producing	4,401	—	4,401	10
Undeveloped	30,520	1,742	40,972	90
Total proved	34,921	1,742	45,373	100
Worldwide				
Producing	1,268,391	27,233	1,431,783	54
Non-Producing	251,215	11,385	319,523	12
Undeveloped	674,085	35,009	884,144	34
Total proved	2,193,691	73,627	2,635,450	100

(1) Net proved reserves exclude royalties and interests owned by others (including net profits interests) and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.
(3) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.
(4) Includes international operations in Hungary and Indonesia.

There are considerable uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control, particularly where such reserves are not currently producing or developed. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. 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 the natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development drilling or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced.

In addition, during 2003, we sold reserves totaling over 500 Bcfe to various third parties. The reserves sold were primarily located in Oklahoma, New Mexico, Texas, Louisiana, the Gulf of Mexico and western Canada. See Part II, Item 8, Financial Statements and Supplementary Data, Note 30, for a further discussion of our reserves.

Acreage and Wells

The following table details our gross and net interest in developed and undeveloped onshore, offshore, coal seam and international lease and mineral acreage at December 31, 2003. 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)
U.S.						
Onshore	931,658	288,500	1,253,666	874,713	2,185,324	1,163,213
Offshore	601,973	415,661	686,892	639,028	1,288,865	1,054,689
Coal Seam	245,200	176,240	1,254,971	1,032,453	1,500,171	1,208,693
Total	1,778,831	880,401	3,195,529	2,546,194	4,974,360	3,426,595
International						
Australia	—	—	355,000	177,500	355,000	177,500
Bolivia	—	—	154,840	15,484	154,840	15,484
Brazil(3)	—	—	2,137,770	1,468,371	2,137,770	1,468,371
Canada(4)	79,068	61,824	799,250	633,940	878,318	695,764
Hungary	77,376	77,376	—	—	77,376	77,376
Indonesia(4)	—	—	1,213,170	378,397	1,213,170	378,397
Turkey	—	—	3,653,483	1,826,742	3,653,483	1,826,742
Total	156,444	139,200	8,313,513	4,500,434	8,469,957	4,639,634
Worldwide Total	1,935,275	1,019,601	11,509,042	7,046,628	13,444,317	8,066,229

(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.
(3) In April 2004, we announced the sale of 174,679 gross and net acres associated with our Brazilian offshore operations.
(4) As of September 2004, we have sold our production operations in Canadian and substantially all of our operations in Indonesia.

The U.S. net developed acreage is concentrated primarily in the Gulf of Mexico (47 percent), Utah (15 percent), Texas (9 percent), Louisiana (8 percent), and Oklahoma (8 percent). The domestic net undeveloped acreage is concentrated primarily in the Gulf of Mexico (25 percent), New Mexico (21 percent), and Louisiana (11 percent). Approximately 20 percent, 14 percent and 7 percent of our total U.S. net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2004, 2005 and 2006, respectively. During 2003, we sold approximately 956,513 net acres primarily located in Oklahoma, New Mexico, Texas, Louisiana, the Gulf of Mexico and western Canada.

The following table details our gross and net interests in productive onshore, offshore, coal seam and international natural gas and oil wells and the number of wells being drilled at December 31, 2003:

	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)]
U.S.								
Onshore	1,320	1,051	271	202	1,591	1,253	16	8
Offshore	360	248	75	42	435	290	5	3
Coal Seam	1,720	1,277	—	—	1,720	1,277	65	47
Total	3,400	2,576	346	244	3,746	2,820	86	58
International								
Canada[(3)]	88	74	7	5	95	79	1	1
Other	1	1	—	—	1	1	—	—
Total	89	75	7	5	96	80	1	1
Worldwide Total	3,489	2,651	353	249	3,842	2,900	87	59

(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.
(3) As of September 2004, we have sold our production operations in Canada.

During 2003, we sold approximately 715 net productive wells located primarily in Oklahoma, New Mexico, Texas, Louisiana, the Gulf of Mexico and western Canada. At December 31, 2003, we operated 2,774 of the 2,900 net productive wells.

The following table details our net exploratory and development wells drilled for each of the three years ended December 31. As a result of the restatement of our proved natural gas and oil reserves, some wells drilled that were previously reported as development wells have been reclassified as exploratory wells in 2002 and 2001. See Part II, Item 8, Financial Statement and Supplementary Data, Note 1 for a further discussion of this restatement.

	Net Exploratory Wells Drilled[(1)]			Net Development Wells Drilled[(1)]		
	2003	2002 (Restated)	2001 (Restated)	2003	2002 (Restated)	2001 (Restated)
U.S.						
Productive	54	27	24	272	511	442
Dry	22	14	10	1	5	21
Total	76	41	34	273	516	463
Canada[(2)]						
Productive	10	18	21	3	5	38
Dry	6	27	35	1	1	3
Total	16	45	56	4	6	41
Brazil						
Productive	3	—	—	—	—	—
Dry	—	—	5	—	—	—
Total	3	—	5	—	—	—
Other Countries[(2)(3)]						
Productive	—	1	—	—	—	—
Dry	1	1	5	—	—	—
Total	1	2	5	—	—	—

	Net Exploratory Wells Drilled[1]			Net Development Wells Drilled[1]		
	2003	2002 (Restated)	2001 (Restated)	2003	2002 (Restated)	2001 (Restated)
Worldwide						
Productive	67	46	45	275	516	480
Dry	29	42	55	2	6	24
Total	96	88	100	277	522	504

(1) Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.
(2) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.
(3) Includes international operations in Australia, Hungary, Turkey and Indonesia.

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

Net Production, 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 average production taxes associated with the sale of natural gas and oil for each of the three years ended December 31. See our Production segment in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations for a further discussion of volumes, prices and production costs.

	2003	2002 (Restated)	2001 (Restated)
Net Production Volumes			
U.S.			
Natural Gas (Bcf)	339	470	552
Oil, Condensate and Liquids (MMBbls)	12	17	13
Total (Bcfe)	410	569	634
Canada[1]			
Natural Gas (Bcf)	15	17	13
Oil, Condensate and Liquids (MMBbls)	—	1	1
Total (Bcfe)	17	23	17
Worldwide			
Natural Gas (Bcf)	354	487	565
Oil, Condensate and Liquids (MMBbls)	12	18	14
Total (Bcfe)	427	592	651
Natural Gas Average Sales Price (per Mcf)[2]			
U.S.			
Price, excluding hedges	$ 5.51	$ 3.17	$ 4.26
Price, including hedges[3]	$ 5.40	$ 3.35	$ 3.81
Canada[1]			
Price, excluding hedges	$ 4.87	$ 2.85	$ 2.86
Price, including hedges	$ 4.87	$ 2.84	$ 2.85
Worldwide			
Price, excluding hedges	$ 5.48	$ 3.16	$ 4.23
Price, including hedges[3]	$ 5.38	$ 3.33	$ 3.79
Oil, Condensate, and Liquids Average Sales Price (per Bbl)[2]			
U.S.			
Price, excluding hedges	$26.64	$21.38	$23.08
Price, including hedges[3]	$25.96	$21.28	$22.83

	2003	2002 (Restated)	2001 (Restated)
Canada[1]			
Price, excluding hedges	$28.38	$21.56	$17.68
Price, including hedges	$28.38	$21.55	$18.52
Worldwide[1]			
Price, excluding hedges	$26.69	$21.39	$22.87
Price, including hedges[3]	$26.02	$21.30	$22.66
Average Transportation Cost			
U.S.			
Natural gas (per Mcf)	$ 0.18	$ 0.18	$ 0.11
Oil, condensate and liquids (per Bbl)	$ 1.05	$ 0.97	$ 0.57
Canada[1]			
Natural gas (per Mcf)	$ 0.86	$ 0.19	$ 0.17
Oil, condensate and liquids (per Bbl)	$ 0.72	$ 0.39	$ 0.26
Worldwide			
Natural gas (per Mcf)	$ 0.21	$ 0.18	$ 0.12
Oil, condensate and liquids (per Bbl)	$ 1.05	$ 0.93	$ 0.56
Average Production Cost (per Mcfe)			
U.S.			
Average lease operating cost	$ 0.42	$ 0.42	$ 0.37
Average production taxes	0.14	0.08	0.14
Total production cost[4]	$ 0.56	$ 0.50	$ 0.51
Canada[1]			
Average production cost	$ 0.48	$ 0.80	$ 0.74
Worldwide			
Average lease operating cost	$ 0.42	$ 0.43	$ 0.38
Average production taxes	0.14	0.08	0.14
Total production cost[4]	$ 0.56	$ 0.51	$ 0.52

(1) As of September 2004, we have sold our production operations in Canada.
(2) Prices are stated before transportation costs.
(3) These amounts have been restated as a result of our determination that a number of our hedges in historical periods did not qualify as hedges for consolidated reporting purposes.
(4) 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. As a result of the restatement of our proved natural gas and oil reserves, some costs that were previously reported as development costs have been reclassified as exploratory drilling costs for the years 2002 and 2001. See Part II, Item 8, Financial Statements and Supplementary Data, Notes 1 and 30, for a further discussion of this restatement.

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.			
Acquisition Costs:			
Proved	$ 10	$ 362	$ 91
Unproved	35	29	44
Development Costs	668	1,242	1,374
Exploration Costs:			
Delay Rentals	6	7	14
Seismic Acquisition and Reprocessing	56	35	37
Drilling	405	482	281
Total	$1,180	$2,157	$1,841
Canada(1)			
Acquisition Costs:			
Proved	$ 1	$ 6	$ 232
Unproved	10	7	16
Development Costs	57	80	102
Exploration Costs:			
Seismic Acquisition and Reprocessing	9	21	10
Drilling	35	49	12
Total	$ 112	$ 163	$ 372
Brazil			
Acquisition Costs:			
Unproved	$ 4	$ 9	$ 24
Exploration Costs:			
Seismic Acquisition and Reprocessing	11	32	6
Drilling	84	13	53
Total	$ 99	$ 54	$ 83
Other Countries(1)(2)			
Acquisition Costs:			
Unproved	$ —	$ 1	$ 2
Development Costs	2	2	—
Exploration Costs:			
Seismic Acquisition and Reprocessing	2	2	—
Drilling	9	12	58
Total	$ 13	$ 17	$ 60

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Worldwide			
Acquisition Costs:			
Proved	$ 11	$ 368	$ 323
Unproved	49	46	86
Development Costs	727	1,324	1,476
Exploration Costs:			
Delay Rentals	6	7	14
Seismic Acquisition and Reprocessing	78	90	53
Drilling	533	556	404
Total	$1,404	$2,391	$2,356

(1) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.
(2) Includes international operations in Australia, Hungary, Indonesia and Turkey.

The following table details approximate amounts spent to develop proved undeveloped reserves that were included in our reserve report for each of the three years:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.	$ 220	$ 275	$ 49
Canada	—	3	3
Total	$ 220	$ 278	$ 52

Regulatory and Operating Environment

Our natural gas and oil production activities are regulated at the federal, state and local levels, as well as internationally by the countries around the world where 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, 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 on our production business for 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 life or property. In addition, 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 on behalf of our production activities with respect to potential losses resulting from these operating hazards.

Markets and Competition

We primarily sell our natural gas and oil to third parties through our Merchant Energy segment at spot market prices, subject to customary adjustments. As part of our Long-Range Plan, we will continue to sell our natural gas and oil production to this segment. 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 operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price and contract terms. 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.

Unregulated Businesses — Field Services Segment

Our Field Services segment conducts our midstream activities which includes gathering and processing of natural gas. Our Field Services assets principally consist of our consolidated processing assets in south Texas and south Louisiana, and our general and limited partner holdings of GulfTerra, a publicly traded master limited partnership in which our subsidiary serves as the general partner. GulfTerra provides services that include gathering, transportation, separation, handling, processing, fractionation and storage of natural gas, oil and natural gas liquids.

Until the fourth quarter of 2003, we owned 100 percent of the general partner of GulfTerra. In December 2003, we sold 50 percent of this ownership interest to Enterprise Products Partners, L.P. (Enterprise) as discussed below. We will sell our remaining interest in the general partner to Enterprise upon the completion of the merger described below for $370 million in cash and a 9.9 percent interest in the general partner of the combined entity.

Gathering and Processing Operations

Our gathering and processing operations provide gathering and processing services to natural gas producers, primarily in the south Texas and south Louisiana production areas. The following tables provide information regarding operational capacity and volumes of these gathering and processing facilities:

Gathering	December 31, 2003 Miles of Pipeline	December 31, 2003 Throughput Capacity (MMcfe/d)	Average Throughput 2003	2002 (BBtue/d)	2001
South Texas[1]	127	966	188	1,089	3,542
Other areas	835	35	169	1,934	2,567
Total	962	1,001	357	3,023	6,109

Processing Plants	Inlet Capacity December 31, 2003 (MMcfe/d)	Average Inlet Volume 2003	2002 (BBtue/d)	2001	Average Natural Gas Liquids Sales 2003	2002 (Mgal/d)	2001
South Texas[1]	2,030	1,491	1,637	1,557	2,418	2,956	2,895
South Louisiana	2,550	1,627	1,407	1,712	1,726	1,604	1,619
Other areas	56	88	876	1,091	193	2,178	2,608
Total	4,636	3,206	3,920	4,360	4,337	6,738	7,122

(1) Substantially all of these assets will be sold in 2004 as part of the Enterprise transaction discussed below.

During 2002 and 2003, we completed a number of sales of our midstream assets, including the sale of our San Juan Basin gathering, treating and processing assets and our Texas and New Mexico midstream assets, including the intrastate natural gas pipeline system we acquired from Pacific Gas & Electric Company in 2000, to GulfTerra. Under our Long-Range Plan, we intend to divest the remaining processing assets or manage them as part of our unregulated businesses.

Investment in GulfTerra

We currently serve as the managing member of GulfTerra's general partner. As the managing member of the general partner, we manage the partnership's daily operations and perform all of GulfTerra's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. The following table provides information on the facilities of GulfTerra:

	December 31, 2003		Average Throughput		
	Miles of Pipeline	Throughput Capacity	2003	2002	2001
		(MMcfe/d)		(BBtue/d)	
Gathering assets[1]	15,536	10,905	6,820	6,686	1,946

	Inlet Capacity	Average Inlet Volume			Average Natural Gas Liquids Sales		
	December 31, 2003	2003	2002	2001	2003	2002	2001
	(MMcfe/d)		(BBtue/d)			(Mgal/d)	
Processing assets[1]	950	791	729	—	2,072	266	—

(1) All volumetric information reflects 100 percent of GulfTerra's interest.

As of December 31, 2003, we owned 17.8 percent, or 10,384,245, of GulfTerra's voting common units and a 50 percent ownership interest in GulfTerra's one percent general partner. We also owned all 10,937,500 of the partnership's outstanding Series C units, which are non-voting but are convertible into common units. Until October 2003, we owned all of the Series B preference units of the partnership, which GulfTerra redeemed for $156 million at that time. The remaining 82.2 percent of the partnership's common units are owned by public unit holders (including small amounts owned by management and employees of the general partner), none of which exceeds a 10 percent ownership interest.

GulfTerra Merger with Enterprise

In December 2003, Enterprise and GulfTerra announced that they had executed definitive merger agreements to form the second largest publicly traded energy partnership in the United States. The general partner of the combined partnership was to be jointly owned by us and affiliates of privately held Enterprise Products Company, with each owning a 50 percent interest. In 2004, we amended our agreement with Enterprise Products Company whereby we will sell our remaining interest in the general partner of GulfTerra, in exchange for an additional payment to us of $370 million and a 9.9 percent interest in the general partner of the combined entity. In conjunction with the merger, we will also sell to Enterprise a portion of our common units, all of our Series C units in GulfTerra and substantially all of our south Texas gathering and processing assets. Following the completion of these transactions, our Field Services segment will own a 9.9 percent interest in the general partner of Enterprise, approximately four percent of Enterprise's common units and processing plants located primarily in south Louisiana.

The combined partnership, which will retain the name Enterprise Products Partners L.P., will provide transportation, gathering, processing, and treating services in the largest producing basins of natural gas, crude oil and natural gas liquids (NGL) in the U.S., including the Gulf of Mexico, Rocky Mountains, San Juan Basin, Permian Basin, south Texas, east Texas, Mid-Continent, Louisiana Gulf Coast and, through connections with third-party pipelines, Canada's western sedimentary basin. The partnership will also serve the largest consuming regions for natural gas, crude oil and NGL on the U.S. Gulf Coast.

In July 2004, the unitholders of both Enterprise and GulfTerra approved the merger and related transactions. The merger and related transactions are discussed more fully in Part II, Item 8, Financial Statements and Supplementary Data, Note 28.

Regulatory Environment

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

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

In addition, some of 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's. 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's. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service and access to favorable downstream markets.

Unregulated Businesses — Merchant Energy Segment

Our Merchant Energy segment consists of a Global Power division, an Energy Marketing and Trading division and an LNG division.

Global Power

Our Global Power division includes the ownership and operation of domestic and international power generation facilities as well as the management of restructured power contracts. As of December 31, 2003, we owned or had interests in 68 power facilities in 16 countries with a total generating capacity of 14,898 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. During 2003, we actively pursued the sale of most of our domestic plants and in December 2003, our Board of Directors authorized a plan that included the sale of substantially all of our domestic power generation plants. As of September 2004, we have sold 23 domestic power plants with a total generating capacity of 2,480 gross MW. Following these sales, we anticipate that we will continue to own interests in several domestic plants and own several power purchase and supply contracts related to our power restructuring business discussed below. We will also continue to seek opportunities to sell or otherwise divest these remaining domestic assets and some of our international assets, such that our long-term focus will be on maximizing the value of our international power assets primarily in Brazil.

Domestic Power. As of December 31, 2003, we owned or had direct investment interests in the following domestic power plants:

Project	State	El Paso Ownership Interest	Gross Capacity	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
		(Percent)	(MW)			
Sold in 2004						
Ace[1]	CA	48	107	SOCAL Edison	2015	Coal
Bastrop[1]	TX	50	534	—[2]	—[2]	Natural Gas
Bayonne	NJ	100	186	—[2]	—[2]	Natural Gas
Bonneville/NCA[1]	NV	50	85	Nevada Power	2023	Natural Gas
Camden	NJ	100	149	—[2]	—[2]	Natural Gas
Dartmouth	MA	100	68	N-Star	2017	Natural Gas
Fulton	NY	100	48	—[2]	—[2]	Natural Gas
Juniper[1][3]	CA	51[3]	682	PG&E, SOCAL Edison	2009-2020	Natural Gas
Newark Bay	NJ	100	147	—[2]	—[2]	Natural Gas
Orange[1]	FL	50	104	FPC, TECO	2025	Natural Gas
Orlando[1]	FL	50	115	FPC, Reedy Creek	2012, 2023	Natural Gas
Panther Creek[1]	PA	50	82	Metropolitan Edison	2012	Coal
Polk Power (Mulberry)[1]	FL	50	121	FPC	2024	Natural Gas
Prime Energy[1]	NJ	50	52	GPU Energy, Marcal	2009	Natural Gas
Under Contract for Sale						
Cambria	PA	100	80	GPU Energy	2011	Coal
Colver[1]	PA	28	106	Penn Electric	2020	Coal
Front Range[1]	CO	50	500	Colorado Springs Utilities	2023	Natural Gas
Gilberton[1]	PA	10	82	Penn Power & Light	2007	Coal
MassPower[1]	MA	50	270	BECO	2011	Natural Gas
Mid-Georgia[1]	GA	50	308	Georgia Power	2028	Natural Gas
Mt. Poso[1]	CA	16	58	PG&E	2009	Coal
Vandolah	FL	100	645	Reliant	2012	Natural Gas
Approved for Sale[4]						
CDECCA	CT	100	62	—[2]	—[2]	Natural Gas
Pawtucket	RI	100	69	—[2]	—[2]	Natural Gas
Rensselaer	NY	100	86	—[2]	—[2]	Natural Gas
San Joaquin	CA	100	48	—[2]	—[2]	Natural Gas
Other Power Plants						
Midland[1]	MI	44	1,575	Consumers Power, Dow	2025	Natural Gas
Berkshire[1]	MA	56	261	—[2]	—[2]	Natural Gas
Eagle Point[5]	NJ	100	233	—[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 energy marketing and trading division sells the power that a majority of these facilities generate to the wholesale power market.

(3) Represents our ownership interest in the Juniper holding company. This company owns equity interests in 10 domestic power facilities.

(4) In December 2003, our Board approved a plan for selling these power facilities.

(5) This power facility is currently being leased to a third party who has an option to purchase in 2005.

Prior to 2003, we conducted a significant portion of our domestic power activity through our ownership in Chaparral, an unconsolidated joint venture formed for the purpose of investing in the domestic power industry. During the first six months of 2003, we acquired our joint venture partner's interest and began consolidating Chaparral effective January 1, 2003.

In addition to our domestic power plants above, we were involved in activities in 2001 and 2002 that we have referred to as our power restructuring business. These activities 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. Our power restructuring activities included restructuring the contracts held by our consolidated power plants such as our Eagle Point power facility, and restructuring of contracts at plants owned by Chaparral, such as Chaparral's Newark Bay, Bayonne and Camden power facilities. In a restructuring, the contracts were amended so that the power sold to the utilities did not have to be provided from the specific power plant, but could be obtained in the wholesale power market. While we are no longer actively seeking to restructure additional power purchase contracts, we continue to manage the physical purchase and sale of electricity as required under the following previously restructured power contracts:

Project	Power Purchaser	Minimum Annual Volume	Expiration Year of Power Sales Contract	Power Supplier
		(MW)		
Cedar Brakes I	PSEG	394	2013	El Paso Merchant Energy
Cedar Brakes II	PSEG	721	2013	El Paso Merchant Energy
Mohawk River Funding II	Niagara Mohawk	663	2008	El Paso Merchant Energy
Mohawk River Funding IV[(1)]	Connecticut Power and Light	97	2008	Constellation Power
Utility Contract Funding[(1)]	PSEG	1,666	2016	Morgan Stanley

(1) We sold these restructured power contracts in 2004.

International Power. As of December 31, 2003, 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	895	Petrobras[(3)]	2007	Natural Gas
Manaus	Brazil	100	238	Manaus Energia	2005	Oil
Porto Velho[(1)]	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro	Brazil	100	158	Manaus Energia	2006	Oil
Central and other South America						
Aguaytia[(1)]	Peru	24	155	Various	2005, 2006	Natural Gas
Fortuna[(1)]	Panama	25	300	Union Fenosa	2004, 2005	Hydroelectric
Itabo[(1)]	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Nejapa	El Salvador	87	144	AES and PPL	2004, 2005	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	25	734	Fujian Power	2025	Coal
Haripur[(1)]	Bangladesh	50	116	Bangladesh Power	2014	Natural Gas
PPN[(1)]	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
Europe						
Enfield[(1)]	United Kingdom	25	378	—	—	Natural Gas

(1) These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.

(2) This facility's power sales contract is 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 capacity and revenue under its contract until 2007.

From November 2001 to April 2003, several of our power facilities in Brazil were owned and managed by Gemstone, an unconsolidated joint venture formed for the purpose of investing in the Brazilian power industry. In April 2003, we acquired our joint venture partner's interest and began consolidating Gemstone.

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

Pipeline	El Paso Ownership Interest	Kilometers of Pipeline	Design Capacity[(1)]	Average 2003 Throughput[(1)]
	(Percent)		(MMcf/d)	(BBtu/d)
Bolivia to Brazil	8	3,150	1,059	498
Argentina to Chile	22	540	124	35

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

As discussed above, we are actively divesting substantially all of our domestic power plants, with 23 power plants sold as of September 2004, another 8 power plants currently under sales contracts and most of the remaining domestic plants approved by our Board of Directors for sale. Several of the power plants under sales contracts are subject to rights of existing partners to purchase our interest in such plants and many of the power plants require consents from third parties prior to consummating the sale of the plants. Internationally, our long-term focus is to integrate our Brazilian businesses to better unify our efforts and economies of scale in Brazil. We intend to sell substantially all of our other international power operations, our domestic restructured power contracts and our other domestic power plants as opportunities arise.

Regulatory Environment. 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. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. 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.

Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of the countries in which we conduct business have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures and their interpretation and application by administrative agencies are relatively new, are sometimes limited and are at risk to change, which may affect our contractual arrangements. Many detailed rules and procedures are yet to be issued, and we expect that the interpretation and modification of existing rules in these jurisdictions will evolve over time.

Markets and Competition. Many of our domestic power generation facilities sell power pursuant to long-term power purchase agreements with investor-owned utilities in the U.S. The terms of the power purchase agreements for our facilities are such that our revenues from these facilities are not significantly impacted by competition from other sources of generation. The U.S. power generation industry continues to evolve and regulatory initiatives have been adopted at the federal and state levels aimed at increasing competition in the power generation business. As a result, it is likely that when the power purchase agreements expire, these facilities will be required to compete in the same market as our other power facilities without power purchase agreements, in which operating efficiency and other economic factors determine success. We are likely to face intense competition from generation companies as well as from the wholesale power markets.

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 and competitive risks.

Energy Marketing and Trading

During 2001 and 2002, we entered into a variety of physical and financial transactions in the commodity markets. 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 trading portfolio. As part of our

Long-Range Plan, 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. As of December 31, 2003, we had executed contracts with third parties, primarily fixed for floating swaps, that effectively hedged 38.9 TBtu of our Production segment's anticipated natural gas production through 2012. The volumes as of December 31, 2003 have been adjusted for a restatement of the accounting treatment for these hedging activities. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of this restatement. In May 2004, we entered into additional hedges for 5.5 TBtu of our Production segment's anticipated natural gas production through 2007. In addition, in August 2004, we entered into hedges for 1.1 MMBbls of our Production segment's anticipated oil production in Brazil through 2007. As of September 2004, we continued to have a number of transactions from our historical trading portfolio that we are actively working to liquidate.

Our Energy Marketing and Trading division'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 division are as follows:

Natural gas. These contracts include long-term obligations to deliver natural gas to power plants. We currently have seven significant physical natural gas contracts with power plants. These contracts have various expiration dates ranging from 2007 to 2028, with expected obligations under individual contracts with third parties ranging from 30,000 MMBtu/d to 142,000 MMBtu/d. Also included in our natural gas portfolio are other contracts that we use to manage the risk associated with our long-term supply obligations and those historically associated with our merchant LNG business.

Power. These contracts include long-term obligations to provide power to our Global Power division for their restructured domestic power contracts. We currently have four power supply contracts with the largest of these being a contract with Morgan Stanley for approximately 1.7 MMWh per year extending through 2016. 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.

Tolling. These contracts provide us with the right to require a counterparty 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. We currently have two unaffiliated physical tolling contracts, the largest of which is our contract on the Cordova power project in the Midwest, which has an expiration date of 2019.

Transportation. These contracts give us the right to transport natural gas using pipeline capacity for a fixed demand charge plus variable transportation costs. Our natural gas transportation contracts have 1.7 Bcf/d of capacity as of December 31, 2003 and have contractual 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 and the amount of capital required to support credit demands from our gas suppliers.

Storage. These contracts give us the ability to inject, withdraw and store natural gas in various locations. Through these contracts, we currently have access to storage capacity totaling 22 Bcf as of December 31, 2003 with contractual terms that currently extend through 2007.

Markets and Competition. Our Energy Marketing and Trading division operates in a highly competitive environment. 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.

Our Energy Marketing and Trading division competes 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.

LNG

Our merchant LNG terminalling and transportation business (which does not include the Elba Island facility owned by our Pipelines segment) contracted for LNG terminalling and regasification capacity and coordinated short and long-term LNG supply deliveries. Our merchant LNG terminalling and transportation business owned several terminals under development in Baja, Altimira and the Bahamas. We also held a patent on our Energy Bridge technology and several long-term charter arrangements on ships that employed this technology. This technology involved using ships to liquify and then regasify natural gas for delivery to pipeline offtakers. In 2003, we announced our intent to exit this business because of the significant capital and credit requirements of this business. We have either sold or are in the process of selling all of our merchant LNG terminals, including the remaining assets and intellectual property rights related to our Energy Bridge technology. We are also terminating our remaining obligations under the long-term ship charters related to this technology.

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

Through our corporate group, we perform management, legal, accounting, financial, tax, consulting, administrative and other services for our operating business segments. The costs of providing these services are allocated to our business segments. Our remaining telecommunications business and a retail business (which was sold in 2001 and 2002) and our discontinued operations, which include our petroleum markets and coal businesses, are also included in our corporate activities.

Telecommunications

Our telecommunications business focuses on providing Texas-based metro transport services and collocation and cross-connect services in Chicago. Our Texas metro transport business provides bandwidth transport services to wholesale and commercial customers in Austin, San Antonio, Dallas, Ft. Worth and Houston. Our collocation and cross-connect services are available through our Chicago telecommunications facility, the Lakeside Technology Center. This facility provides space for telecommunication carriers that is designed for their unique equipment needs and provides access to multiple network connections of various telecommunication carriers. As of December 31, 2003, we had approximately $160 million of remaining assets in our telecommunications business, primarily consisting of our Texas metro transport business and our Lakeside Technology Center. In April 2004, we sold a 28 percent interest in our Texas metro transport business to Genesis Park, L.P., a third party investment partnership, and the name of that business was changed to Alpheus Communications.

Discontinued Operations

Our discontinued operations consist of our petroleum markets and coal mining businesses.

Petroleum Markets. In 2003, we announced our intent to sell our petroleum markets business since it was not core to our primary natural gas business. During 2003 and 2004, we sold substantially all of our petroleum markets assets. As of December 31, 2003, our petroleum markets business owned or had interests in two crude oil refineries and two chemical production facilities and had petroleum terminalling and related marketing operations. Our refineries operated at 74 percent of their combined daily capacity in 2003, at 66 percent in 2002 and at 71 percent in 2001. The aggregate sales volumes at our wholly owned refineries were approximately 118 MMBbls in 2003, 110 MMBbls in 2002 and 131 MMBbls in 2001. Of our total refinery sales in 2003, 24 percent was gasoline, 38 percent was middle distillates, such as jet fuel, diesel fuel and home heating oil, and 38 percent was heavy industrial fuels and other products. The following table presents information on our wholly owned refineries as of and for the years ended December 31:

		Average Daily Throughput			As of December 31, 2003	
Refinery	**Location**	**2003**	**2002**	**2001**	**Daily Capacity**	**Storage Capacity**
		(In MBbls)				
Aruba[(1)]	Aruba	173	146	178	280	14,652
Eagle Point[(2)]	Westville, New Jersey	140	127	118	150	8,492
Mobile[(3)]	Mobile, Alabama	6	9	10	—	—
Total		319	282	306	430	23,144

(1) In March 2004, we completed the sale of our Aruba refinery to Valero Energy Corporation.

(2) In January 2004, we completed the sale of our Eagle Point refinery to Sunoco Corporation.

(3) In July 2003, we sold our Mobile refinery to Trigeant EP. Ltd. These volumes only reflect those produced prior to the sale of the refinery.

Our chemical plants produce gasoline additives and paraxylene at our facilities in Wyoming and Montreal. The following table provides information on sales volumes from our wholly owned chemical facilities in the U.S. for each of the three years ended December 31:

	2003	**2002**	**2001**
		(MTons)	
Industrial[(1)]	352	512	492
Agricultural[(1)]	417	380	378
Gasoline additives[(2)]	139	199	173
Total	908	1,091	1,043

(1) In December 2003, we sold our chemical facilities that produced nitrogen-based industrial and agricultural products to Dyno Nobel, Inc. We expect to sell our remaining chemical facilities in the fourth quarter of 2004.

(2) Removed from service in October 2003.

Our petroleum markets business is subject to federal, state and local environmental regulations and its customers are principally independent energy marketers and retailers.

Coal Mining. Prior to its discontinuance in 2002, our coal mining business controlled reserves totaling 524 million recoverable tons and produced high-quality bituminous coal from reserves in Kentucky, Virginia and West Virginia. The extracted coal was primarily sold under long-term contracts to power generation facilities in the eastern U.S. During late 2002 and early 2003, these operations were sold.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 22, and is incorporated herein by reference.

Employees

As of September 24, 2004, we had approximately 7,574 full-time employees, of which 34 are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of September 10, 2004, 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
John W. Somerhalder II	Executive Vice President of El Paso and President of El Paso Pipeline Group	1990	48
Robert W. Baker	Executive Vice President and General Counsel of El Paso	1996	48
Robert G. Phillips	President of El Paso Field Services	1995	49
Lisa A. Stewart	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. Prior to that, 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. He held various positions in finance and new business ventures with ARCO International Oil and Gas Company and spent seven years in commercial banking, primarily as an energy lender.

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. From January 1999 to October 2000, he served as a managing director in the energy investment banking practice of Donaldson, Lufkin and Jenrette.

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. He was President of Tennessee Gas Pipeline Company from December 1996 to January 2000, President of El Paso Energy Resources Company from April 1996 to December 1996 and Senior Vice President of El Paso from August 1992 to April 1996.

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.

Robert G. Phillips has been President of El Paso Field Services since June 1997. He was President of El Paso Energy Resources Company from December 1996 to June 1997, President of El Paso Field Services from April 1996 to December 1996 and was Senior Vice President of El Paso from September 1995 to April 1996. Prior to that period, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc. Mr. Phillips is the Chairman of the Board of Directors of GulfTerra Energy Company, L.L.C., the general partner of GulfTerra Energy Partners, L.P.

Lisa A. Stewart has been 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 Securities and Exchange Commission (SEC). 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

More details on the cases listed below and a description of our legal proceedings are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 22, 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 shareholder derivative actions filed in Houston 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. 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 shareholder derivative lawsuit filed in Delaware is *Stephen Brudno et al v. William A. Wise et al* filed in October 2002.

The ERISA Class Action Suit is *William H. Lewis III v. El Paso Corporation, H. Brent Austin et al.* It is pending in the U.S. District Court for the Southern District of Texas, Houston Division.

The following is a description of environmental proceedings to which a governmental authority is a party and potential monetary sanctions are $100,000 or more.

Kentucky PCB Project. In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of 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 response to a request from LDEQ, SNG submitted a detailed report to LDEQ in September 2003, documenting that there had been unpermitted emissions from nine condensate storage tanks and a tank truck loading station. In December 2003, LDEQ issued a Consolidated Compliance Order and Notice of Potential Penalty requiring SNG to complete certain tasks to correct the existing operating permit and achieve compliance with federal and state laws and regulations. SNG's Toca Compressor Station will invest an estimated $6 million to upgrade the station's environmental controls by 2005. SNG filed a revised permit application and plan for compliance in January 2004. On May 6, 2004, LDEQ and SNG agreed to settle the enforcement matter for a penalty of $66,000.

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 NOE included a draft Agreed Order assessing a penalty of $365,750 for the cited violations. The alleged violations pertained to exceeding the emission limit, testing, reporting, and recordkeeping issues in 2001. We have responded to the NOE disputing the alleged violation and the proposed penalty.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality (TCEQ) 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 have filed a hearing request to protect our procedural rights and have initiated negotiations with the TCEQ.

Coastal Eagle Point. The Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental

Protection (DEP). The Orders alleged noncompliance with the New Jersey Air Pollution Control Act, primarily pertaining to excess emissions reported since 1998 by the Eagle Point refinery in Westville, New Jersey. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair (LDAR) program. Alleged violations include a failure to monitor all components and failure to timely repair leaking components. The Eagle Point refinery resolved the claims of the U.S. and the State of New Jersey in a Consent Decree on September 30, 2003, pursuant to the EPA's refinery enforcement initiative. The Consent Decree was entered on December 2, 2003. We paid a civil penalty of $1.25 million to the U.S. and $1.25 million to New Jersey. We contributed $1.0 million to an environmentally beneficial project near the refinery. The Eagle Point refinery will invest an estimated $3 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 DEP 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 at the refinery, prior to the sale. We are reviewing the information behind the excess emission events and 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. The EPA has alleged violations of the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and the Emergency Planning and Community Right-to-Know Act (EPCRA) reporting requirements associated with the reporting of the release. 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 the alleged violations. We responded to the EPA's demand, and we have resolved the alleged violations by agreeing to a penalty of $50,345 and by agreeing to conduct 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 and we are in negotiations with the EPA as to the appropriate penalty.

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

None.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of September 24, 2004, we had 51,553 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			
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
2002			
Fourth Quarter	$11.91	$ 4.39	$0.2175
Third Quarter	21.07	5.30	0.2175
Second Quarter	46.80	18.88	0.2175
First Quarter	46.89	31.70	0.2175

On July 16, 2004, we declared quarterly dividends of $0.04 per share of our common stock, payable on October 4, 2004, to shareholders of record as of September 3, 2004. Future dividends will be dependent upon business conditions, earnings, our cash requirements and other relevant factors.

Equity Security Units

In June 2002, we issued 11.5 million, 9% 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% 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%. 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. For each unit tendered, the holder received 2.5063 shares of common stock and cash in the amount of $9.70 per equity security unit. 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. The common stock was issued under Section 3(a)(9) of the Securities Act of 1933.

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.

A description of our equity compensation plan information is included in Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, and is incorporated herein by reference.

ITEM 6. SELECTED FINANCIAL DATA

The information for the years from 1999 until 2002 and for the first nine months of 2003 has been restated. For a further discussion of this restatement and the 2003, 2002 and 2001 restatement amounts, see Item 8, Financial Statements and Supplementary Data, Note 1. See the notes to the table below for the impact of this restatement on 2000 and 1999. The following historical selected financial data excludes 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 Item 8, Financial Statements and Supplementary Data included in this Annual Report on Form 10-K. 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,				
	2003	2002 (Restated)[1]	2001 (Restated)[1]	2000 (Restated)[1][2]	1999 (Restated)[1][2]
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 6,711	$ 6,917	$10,214	$ 6,181	$ 5,246
Depreciation, depletion and amortization	1,207	1,180	1,380	1,170	973
Ceiling test charges[3]	76	128	2,143	—	121
Operating income (loss)[3]	275	(263)	291	1,250	913
Income taxes (benefit)	(584)	(649)	(70)	150	185
Income (loss) from continuing operations available to common stockholders[3]	(616)	(1,334)	(388)	471	441
Basic earnings (loss) per common share from continuing operations	$ (1.03)	$ (2.38)	$ (0.77)	$ 0.95	$ 0.90
Diluted earnings (loss) per common share from continuing operations	$ (1.03)	$ (2.38)	$ (0.77)	$ 0.93	$ 0.89
Cash dividends declared per common share[4]	$ 0.16	$ 0.87	$ 0.85	$ 0.82	$ 0.80
Basic average common shares outstanding	597	560	505	494	490
Diluted average common shares outstanding	597	560	505	506	497
Financial Position Data:					
Total assets[5]	$37,084	$42,065	$44,565	$44,038	$29,613
Long-term financing obligations[6]	20,275	16,106	12,840	11,206	8,529
Securities of subsidiaries[6]	447	3,420	4,013	3,707	2,444
Stockholders' equity	4,474	5,872	6,666	6,145	5,552

(1) In February 2004, we completed an assessment of our December 31, 2003 proved natural gas and oil reserve estimates. The assessment indicated a downward revision to our proved reserve estimates of 1.8 Tcfe was needed. Upon completion of an investigation into the factors that caused this revision, we determined that a material portion of the revision should be reflected in all of the historical periods included in this Annual Report on Form 10-K. As a result, we restated our historical financial statements for all periods to reflect the impacts of the revised reserve estimates on the financial statement amounts. In August 2004, we also determined that we had not properly applied generally accepted accounting principles related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. After an investigation into this matter, we determined that a further restatement of our financial statements would be required. The cumulative impact of the restatements on total stockholders' equity as of September 30, 2003 (the most recent balance sheet filed) was a reduction of approximately \$2.4 billion. Of this amount, \$1.7 billion related to our restatement for reserves and \$0.7 billion related to the restatement for certain hedges. The cumulative impact includes a reduction to beginning stockholders' equity as of January 1, 2001 of approximately \$2.0 billion, of which \$1.3 billion relates to our restatement for reserves and \$0.7 billion relates to the restatement for certain hedges. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of our restatement processes as well as

the financial impacts of the restatements on 2001, 2002 and 2003. The financial impacts on 1999 and 2000 of the restatements were as follows:

	2000		1999	
	Reported	Restated	Reported	Restated
	(In millions)			
Income from continuing operations available to common stockholders	$ 1,113	$ 471	$ 226	$ 441
Basic earnings per common share from continuing operations	2.25	0.95	0.46	0.90
Diluted earnings per common share from continuing operations	2.19	0.93	0.46	0.89
Total assets	46,903	44,038	32,090	29,613
Stockholders' equity	8,119	6,145	6,884	5,552

The restated stockholders' equity at December 31, 1999 includes an increase in 1999 income of $215 million, net of tax, due to a reduced ceiling test charge, lower depletion expense and the recognition of income that was previously deferred on hedges of our natural gas production. It also includes a reduction to beginning retained earnings of $1.5 billion for charges that would have occurred in periods prior to January 1, 1999 as a result of our revised reserve levels. As discussed in Item 8, Financial Statements and Supplementary Data, Note 1, we revised our reserve estimates for the periods from December 31, 2000 to September 30, 2003 using a reserve reconstruction approach. For each quarter from December 31, 1998 through the third quarter of 2000, we estimated reserves using an approach that involved the use of a "reserve over production ratio" based on the reconstructed December 31, 2000 reserve estimates. The reserve over production ratio provided the estimated life of reserves based on production levels. We applied that ratio to the actual historical period production levels to calculate estimated historical reserves for each period. In determining the reserve over production ratio to use for each period, historical prices at the end of each quarter were considered, since at different pricing levels, more or less reserves are economical to produce, which also impacts capital cost, operating cost and revenue assumptions in determining cash flows that will be derived from reserves. These overall quarterly reserve levels were then used to recalculate the associated net future cash flows for each quarter during those periods. Ceiling test charges and depreciation, depletion and amortization rates were then determined based on these restated estimated reserve levels and related net future cash flows. Finally, we assessed the reasonableness of our initial adjustment as of December 31, 1998 based on historical prices and our historical capitalized costs prior to that time. Based on that assessment, we believe the amount recorded as a retained earnings adjustment on January 1, 1999 reasonably reflects the financial statement impact of our restated reserve levels that would have occurred prior to that time. We believe the approach used to reconstruct our historical reserves estimates was reasonable in light of the information available to us and the circumstances surrounding our restatement. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of the methodologies used to restate our natural gas and oil reserves and the reasons for the differences in the methods used in computing our restated reserves.

(2) The impacts of the historical restatements for the years ended December 31, 2000 and 1999 have not been audited.

(3) In 2003, we 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. We also incurred losses in 2003 of $1.2 billion and in 2002 of $0.9 billion 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 addition, we incurred ceiling test charges (restated) of $76 million, $128 million and $2,143 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. In 1999, we incurred $557 million of merger related and asset impairment charges primarily related to our merger with Sonat Inc. and incurred $121 million of ceiling test charges (restated). For further discussions of events affecting comparability of our results in 2003, 2002 and 2001, see Item 8, Financial Statements and Supplementary Data, Notes 5 through 9.

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

(5) The increase in total assets during 2000 was a result of the consolidation of Engage Energy US, LP into Coastal Merchant Energy and the growth of our Merchant Energy segment in 2000.

(6) 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 Statement of Financial Accounting Standards (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 78. The historical financial information in this section has been restated, as further discussed in Item 8, Financial Statements and Supplementary Data, Note 1. The information contained in this discussion also presents our petroleum markets and our coal mining businesses as discontinued operations for all periods.

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 midstream assets and investments, a domestic and international power business, an energy marketing and trading business, a small telecommunications business and currently have for sale or have sold petroleum, coal and liquified natural gas businesses. 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. In 2002 and 2003, we spent 87 percent and 91 percent, respectively, of our capital investment dollars in our pipeline, midstream and production businesses.

We have liquidated or divested our interests in many of our non-core assets. Coupled with declines in value of some of our business ventures, these sales have resulted in sales prices that are well below the carrying values of these businesses and assets, resulting in significant recorded losses.

The year ended December 31, 2003 was a year of significant change in our business strategy and our financial condition. In 2003:

- We completed the sale of a number of assets and investments including production properties, 50 percent of the general partner interest in GulfTerra, a significant portion of our worldwide petroleum markets operations, a portion of our domestic power generation operations and our merchant LNG business. Total proceeds from these sales were approximately $3.3 billion;
- We completed a number of financial transactions that allowed us to maintain our access to needed capital to meet our cash requirements, simplify our capital structure, and eliminate a significant amount of off-balance sheet obligations and preferred securities;
- We implemented a cost-reduction program that identified $445 million of cost reductions in our business over 2003 and 2004 and initiated a program targeting an additional $150 million of savings by 2006;
- We completed the Western Energy Settlement which became effective in June 2004, resolving a substantial uncertainty arising from the California energy crisis in 2001; and
- We announced our Long-Range Plan that, among other things, defines our core businesses, establishes a timeline for debt reduction, sets a timetable for exiting non-core businesses and assets and sets financial goals for the company.

Many of the changes we experienced in 2003 resulted in significant losses and declining operating cash flows produced by our businesses. Furthermore, in February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. The results of this process indicated that a significant downward revision to those reserve estimates was needed. In August 2004, we also determined that we had not properly applied generally accepted accounting principles related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. After investigations into these issues, we determined that a restatement of our historical financial information was required. Accordingly, we restated our historical financial statements to reflect the financial impact of these revised proved reserve estimates and to revise our historical accounting for these derivatives. See Item 8, Financial Statements and Supplementary Data, Note 1, for a discussion of these restatements.

The events described above increased the risk involved in owning our securities. Despite the reductions in our credit ratings to well below investment grade, we believe that the Long-Range Plan that we have outlined will allow us to manage these increased risks in an acceptable manner and allow us to again become a strong natural gas company in North America. In the following sections of our Management's Discussion and Analysis, we address these events, our outlook and our Long-Range Plan in greater detail.

Capital Structure

During 2003, we took steps intended to simplify our financial and capital structure, refinance shorter term obligations and reduce guarantees and other "off-balance sheet" obligations, replacing them with direct financial obligations. These actions included entering into a new $3 billion revolving credit facility, acquiring and consolidating a number of entities with existing debt, refinancing shorter-term obligations with longer-term borrowings and redeeming and eliminating preferred interests in our subsidiaries as follows (in millions):

Short-term financing obligations, including current maturities	$ 2,075
Notes payable to affiliates	390
Long-term financing obligations	16,106
Securities of subsidiaries	3,420
Total debt and securities of subsidiaries as of December 31, 2002	21,991
Principal amounts borrowed[1]	4,250
Repayments of principal[1]	(3,982)
Other changes in debt:	
Acquisition of Chaparral and Gemstone[2]	2,578
Operating leases and refinanced securities of subsidiaries	1,018
Reclassifications of preferred interests as long-term financing obligations[3]	625
Sales of entities[4]	(710)
Exchange of equity security units[5]	(303)
Elimination of affiliated obligations	(326)
Redemptions and eliminations of securities of subsidiaries[6]	(2,973)
Other	11
Total debt and securities of subsidiaries as of December 31, 2003	$22,179[7]

(1) Includes $500 million of borrowings and $1,150 million of repayments under our $3 billion revolving credit facility.

(2) Approximately $1.6 billion of this amount relates to non-recourse project financing or contract debt and includes $75 million related to Macae which was consolidated as a consequence of our acquisition of Gemstone in April 2003.

(3) Relates to our adoption of SFAS No. 150. See Item 8, Financial Statements and Supplementary Data, Notes 2, 20 and 21.

(4) Includes $571 million in debt obligations related to the sale of East Coast Power and $139 million related to the sale of Mohawk River Funding I.

(5) See Item 8, Financial Statements and Supplementary Data, Note 24.

(6) Redemptions and eliminations represent preferred interests of consolidated subsidiaries that were either repaid or refinanced as debt.

(7) Does not include $370 million of long-term debt, which was retired in March 2004, related to our Aruba refinery that is classified as discontinued operations and $174 million of debt related to power assets that are classified as held for sale.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Item 8, Financial Statements and Supplementary Data, Note 20.

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 changes in commodity prices or demands for our commodities or services due to weather patterns, 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 overall economic conditions of the industries served by these assets, 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 shelf registration statement as further discussed in Item 8, Financial Statements and Supplementary Data, Note 20. For a further discussion of risks that can impact our liquidity, see our risk factors beginning on page 78. The following is a summary of our cash flow activities between January 1, 2004 and June 30, 2004.

	Six Months Ended June 30, 2004
	(in millions)
Operating Activities	
Net operating cash flow[1]	$ 301
Investing Activities	
Capital expenditures	(837)
Net proceeds from the sale of assets	504
Net change in restricted cash[1]	445
Investing activities of discontinued operations[2]	809
Other	100
Net cash provided by investing activities	$ 1,021
Financing Activities	
Reduction in debt (including discontinued operations)[2]	$(1,347)
Issuance of common stock	73
Dividends	(49)
Other	(16)
Net cash used in financing activities	(1,339)
Change in cash	$ (17)

(1) In 2004, we made payments under the Western Energy Settlement of approximately $602 million, which included $468 million held in escrow as of December 31, 2003. The $602 million payment of this liability is shown as an operating cash outflow and the decrease in restricted cash related to the release of escrowed funds is shown as a cash inflow from investing activities.

(2) Relates primarily to proceeds from the sale of our Aruba refinery.

For the first half of 2004, our discretionary and maintenance capital needs were met primarily through operating cash flows. For the next twelve months, we anticipate that our discretionary and maintenance capital needs will continue to be met primarily through operating cash flows, supplemented by continued recovery of cash provided as collateral to various counterparties and by project financings for our Cheyenne Plains project. Our estimated cash flow and cash requirements may change significantly, and our analysis is intended to provide a better understanding our liquidity outlook.

The following tables reflect our available liquidity as of June 30, 2004 and our estimated sources and uses of funds for the period from July 2004 through June 2005 (in billions):

Sources as of June 30, 2004	
Available cash	$1.0
Available capacity under our $3 billion revolving credit facility[(1)]	1.2
Net available liquidity	$2.2

Estimated cash sources	
Announced asset sales[(2)]	$1.8
Other asset sales	0.3
Anticipated cash sources	$2.1
Estimated cash needs	
Debt maturities	$1.5
Revolving credit facility maturity[(3)]	0.6
Dividends	0.1
Anticipated cash needs	$2.2

(1) Upon the close of the Enterprise transaction, which includes the sale of the Series A and Series C units in GulfTerra that collateralize our revolver, our borrowing capacity under our revolver will decrease by approximately $0.5 billion.

(2) Includes approximately $1.0 billion expected to be received upon completion of the Enterprise transaction and $0.8 billion to be received upon completion of our remaining announced power plant and other asset sales.

(3) Does not reflect $1.1 billion of letters of credit issued pursuant to the $3 billion revolving credit facility. We are in the process of refinancing this facility which matures on June 30, 2005.

Our net available liquidity above includes our $3 billion revolving credit facility that matures on June 30, 2005. The facility is collateralized by our equity interests in TGP, EPNG, ANR, CIG, Southern Gas Storage Company, ANR Storage Company and our Series A common units and Series C units in GulfTerra. We are in the process of negotiating the refinancing of this facility and currently expect to be successful in obtaining this refinancing. In the event we are unable to refinance our existing $3 billion revolving credit facility by June 30, 2005, we would be obligated to repay the outstanding amounts, and make alternative arrangements for the letters of credit issued pursuant to this credit facility. As of June 30, 2004, we had borrowed $600 million and issued approximately $1.1 billion of letters of credit under this credit facility.

Although we expect to successfully refinance all or a portion of our existing $3 billion revolving credit facility, if we were unsuccessful, we believe we could adjust our planned capital expenditures and increase our planned asset sales to meet any shortfall in liquidity, and at the same time provide for the operations of the company. Further, if we were required to repay our obligations under the $3 billion revolving credit facility, many of the assets that currently collateralize this facility, including our equity interests in TGP, EPNG, ANR, CIG, Southern Gas Storage Company, ANR Storage Company and some of our Series A common units in GulfTerra, would become available to support new financing transactions. Although we cannot guarantee the outcome of future events, we believe that this available collateral would be adequate to provide financing sufficient to meet our liquidity needs.

In February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. As a result of this review, we announced that we were significantly reducing our proved natural gas and oil reserve estimates. In August 2004, we also determined that we had not properly accounted for certain derivatives, primarily those related to hedges of our anticipated natural gas production. After investigations into these matters, we concluded that a restatement of our historical financial statements for both of these matters was required.

We believe that the material restatements of our financial statements as discussed in Item 8, Financial Statements and Supplementary Data, Note 1 would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions, specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our $3 billion revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension of time with various lenders until November 30, 2004 to file our first and second quarter 2004 Forms 10-Q, which we expect to meet. If we are unable to file these Forms 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our $3 billion revolving credit facility and various other transactions could be accelerated. As part of obtaining these waivers, we also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default, and limitations on our ability as well as the ability of our subsidiaries to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our $3 billion revolving credit facility could constitute an event of default under some of our other debt agreements. In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP Company (El Paso CGP) and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with these covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived its financial filing requirements through December 31, 2004. The filing of the first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the events of non-compliance resulting from the failure to file financial statements on these subsidiaries. In addition, neither we nor any of our subsidiaries have received a notice of the default caused by our failure, or the failure of our subsidiaries to file financial statements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

Furthermore, the material restatement of our financial statements for the period ended December 31, 2001 could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004. Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

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 it or it provides cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to us via our cash management program due to its expected cash needs. In addition, our ownership interests in a number of our subsidiaries and investments serve as collateral under our revolving credit facility and our other borrowings. If the lenders under the credit facility or those other borrowings were to exercise their rights to this collateral, we could be required to liquidate these investments.

If, as a result of the events described above, we were subject to voluntary or involuntary bankruptcy proceedings, our creditors could attempt to make claims against our subsidiaries, including claims to substantively consolidate those subsidiaries. We believe that claims to substantively consolidate our subsidiaries would be without merit. However, there is no assurance that our creditors would not advance such a claim in a bankruptcy proceeding. If our creditors were able to substantively consolidate our subsidiaries in a bankruptcy proceeding, it could have a material adverse effect on our financial condition and our liquidity.

Despite the events described above, we believe we will be able to meet our liquidity and cash needs for the remainder of 2004 and through June 2005 through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our $3 billion revolving credit facility, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, preferred and/or equity securities. 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 78.

Overview of Cash Flow Activities for 2003

For the years ended December 31, 2003 and 2002, our cash flows are summarized as follows:

	2003	2002 Restated[1]
	(In millions)	
Cash flows from continuing operating activities		
Net loss before discontinued operations	$ (625)	$(1,388)
Non-cash income adjustments	1,929	2,536
Changes in assets and liabilities	1,071	(441)
Cash flows from continuing operating activities	2,375	707
Cash flows from continuing investing activities	(1,616)	(1,092)
Cash flows from continuing financing activities	(921)	828
Discontinued operations		
Cash flows from operating activities	(46)	(271)
Cash flows from investing activities	427	(163)
Cash flows from financing activities	(381)	444
Increase in cash and cash equivalents related to discontinued operations	—	10
Change in cash	(162)	453
Less increase in cash and cash equivalents related to discontinued operations	—	10
Change in cash and cash equivalents from continuing operations	$ (162)	$ 443

(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.

We generated cash from several sources, including our principal continuing operations as well as through our discontinued operations, sales of assets and issuances of long-term debt. We used a major portion of that cash to fund our capital expenditures, purchase additional investments in subsidiaries, retire long-term debt and make payments on amounts outstanding under the revolving credit facilities and redeem preferred interests in several of our subsidiaries held by minority interest owners. Overall, our cash sources and uses during 2003 are summarized as follows (in billions):

Cash inflows	
Cash flows from continuing operating activities	$ 2.4
Net proceeds from the sale of assets and investments	2.5
Net proceeds from the issuance of long-term debt	3.6
Borrowings under revolving credit facility	0.5
Proceeds from the issuance of common stock	0.1
Net discontinued operations activity	0.4
Total cash inflows	9.5
Cash outflows	
Additions to property, plant and equipment	2.5
Net cash paid to acquire Chaparral and Gemstone	1.1
Net payments of restricted cash	0.5
Payments to redeem preferred interests of consolidated subsidiaries	1.3
Payments to retire long-term debt	2.8
Payments on revolving credit facilities	1.2
Dividends paid to common stockholders	0.2
Other	0.1
Total cash outflows	9.7
Net decrease in cash	$(0.2)

Cash From Continuing Operating Activities

Overall, cash generated from continuing operating activities was $2.4 billion during 2003 versus $0.7 billion in 2002. The $1.7 billion year-over-year increase in operating cash flow was due primarily to the timing of cash receipts and payments related to our energy marketing and trading operations. During 2002, increases in natural gas prices and our credit rating downgrades caused us to use approximately $0.9 billion of operating cash flow to meet margin calls on our trading positions. In late 2002, we began actively liquidating the positions in our trading portfolio, in part to recover this cash and as part of the reduction of our involvement in energy trading activities. In 2003, we generated operating cash flow of approximately $0.5 billion primarily from the settlement of positions in our trading portfolio. Since the beginning of 2003, we have recovered $0.1 billion of cash posted for collateral and margin call requirements through the overall reduction in transactions requiring collateral. We have also recovered cash totalling $0.6 billion from our margin calls in 2003 by substituting letters of credit under our $3 billion revolving credit facilities for actual cash on deposit. As a result, our overall margin activity in 2003 was a source of cash of approximately $0.7 billion.

Our cash margin positions are significantly impacted by our credit quality and the credit quality of our counterparties, commodity prices and the availability of letter of credit or other non-cash collateral. Following our credit rating downgrades, credit extended to us by our counterparties was lowered requiring us to post additional margins. Many of our counterparties also posted letters of credit with us requiring us to return their margin deposits. In addition, the impact on our operating cash flows from changes in commodity prices depends on whether the prices of our derivative instruments are above or below market prices at the time. When these prices are below market, as they were in 2002 and 2003, we are required to make margin deposits. However, these margin deposits will be recovered when we sell the underlying commodities and settle the positions or when natural gas prices decrease. At December 31, 2003, we held $0.2 billion of cash and $0.3 billion of letters of credit as collateral from third parties related to our price risk management activities and have posted as collateral $0.2 billion of cash and $0.9 billion letters of credit to third parties related to those activities.

Partially offsetting this overall increase in operating cash flow was a year-over-year $0.4 billion increase in interest payments on our long-term financing obligations, which resulted from the issuance and consolidation of debt in 2003.

Cash From Continuing Investing Activities

Net cash used in our continuing investing activities was $1.6 billion for the year ended December 31, 2003. Our continuing investing activities consisted primarily of capital expenditures and equity investments of $3.6 billion and additions to restricted cash of $0.5 billion, which were offset by net proceeds from sales of assets and investments of $2.5 billion. Our 2003 capital expenditures and net additions to equity investments included the following (in billions):

Production exploration, development and acquisition expenditures[1]	$1.6
Pipeline expansion, maintenance and integrity projects	0.8
Investments in and net advances to unconsolidated affiliates[2]	1.1
Other (primarily power projects)	0.1
Total capital expenditures and net additions to equity investments	$3.6

[1] Amounts include $0.2 billion of capital expenditures paid in 2003 related to projects started and costs accrued in prior years.

[2] Amount is primarily related to purchases of third party investment interests in Chaparral and Gemstone (see Item 8, Financial Statements and Supplementary Data, Note 3).

As indicated above, we currently expect to reduce our total capital expenditures in our Production segment from approximately $1.4 billion in 2003 to approximately $850 million in 2004. In October 2003, we entered into agreements with two separate third parties whereby they agreed to contribute capital for the drilling and completion of two specific packages of wells in exchange for a net profits interest in each well. In 2003, we received funds of approximately $130 million from these third parties under these agreements which supplemented our overall capital program. Additional wells will be drilled under these agreements in 2004, and while one party has elected to cease further investment in one of the specific packages of wells, additional funds will be received in 2004 under these agreements to supplement our 2004 capital program. See Item 8, Financial Statements and Supplementary Data, Note 30, for a further discussion of these agreements.

Cash received from our continuing investing activities includes $2.5 billion from the sale of assets and investments. Our asset sales proceeds primarily relate to sales of natural gas and oil properties in western Canada, New Mexico, Texas, Louisiana, Oklahoma and the Gulf of Mexico for $0.7 billion, the sale of an equity investment in CE Generation for $0.2 billion, the sale of East Coast Power for $0.4 billion, the sale of other pipelines, power and processing assets for $0.6 billion, and the sale of our 50 percent interest in the general partner of GulfTerra and other interests in GulfTerra for $0.6 billion. By segment, sales completed in 2003 and 2002 and those announced to date or completed in 2004 are as follows:

Segment	Completed Sales 2002	Completed Sales 2003	Announced to Date or Completed in 2004
		(In millions)	
Pipelines	$ 303	$ 145	$ 55
Production	1,297	734	410
Field Services	1,513	753	1,020
Merchant Energy	90	853	876
Corporate and Other	—	64	16
Total[(1)]	$3,203	$2,549	$2,377

(1) Excludes proceeds from sales of discontinued operations of $128 million in 2002, $747 million in 2003 and $905 million in 2004.

We will continue to divest our non-core assets based on the strategic direction outlined in our Long-Range Plan (see Item 1, Business for a further discussion of our Long-Range Plan, and Item 8, Financial Statements and Supplementary Data, Notes 4 and 12, for a further discussion of these divestitures and asset divestitures of our discontinued operations).

Cash From Continuing Financing Activities

Net cash used in our continuing financing activities was $0.9 billion for the year ended December 31, 2003. Cash provided from our financing activities included the net proceeds from the issuance of long-term debt of $3.6 billion, $0.4 billion of cash contributed by our discontinued operations and cash generated from the issuance of common stock of $0.1 billion. Cash used in our financing activities included net repayments of $0.7 billion on revolving credit facilities and $2.8 billion of payments made to retire third party long-term debt. We also paid $1.3 billion to fully redeem our Trinity River, Clydesdale and Coastal Securities preferred securities transactions and paid dividends to common stockholders of $0.2 billion. See Item 8, Financial Statements and Supplementary Data, Note 20, for a detail of our financing activities.

Cash Flows of Discontinued Operations

During 2003, our discontinued operations generated $0.4 billion of cash through sales of inventories at our refineries and through asset sales which raised a combined $0.6 billion, offset by capital expenditures of $0.2 billion. These net cash inflows were distributed to our continuing operations.

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 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 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. 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. As of December 31, 2003, we had approximately $277 million of both financial and performance guarantees not otherwise reflected in our financial statements.

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. In these cases, we evaluate at the time the guaranty 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, 2003, we had accrued $78 million related to these arrangements.

Other Arrangements

During 2003, we completed the consolidation and/or repayment of our remaining off-balance sheet obligations including Chaparral, Gemstone, and residual value guarantees related to two operating leases for our Lakeside Technology Center telecommunications facility and our Aruba refinery.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2003, for each of the years presented (all amounts are undiscounted):

	2004	2005	2006	2007	2008	Thereafter	Total
				(In millions)			
Long-term financing obligations:[1]							
Principal	$1,409	$1,585	$1,769	$ 981	$ 776	$15,313	$21,833
Interest	1,519	1,392	1,310	1,211	1,131	12,975	19,538
Western Energy Settlement[2]	633	95	49	45	45	698	1,565
Other contractual liabilities[3]	85	88	106	81	23	37	420
Operating leases[4]	72	69	66	52	44	185	488
Other contractual commitments and purchase obligations:[5]							
Tolling, transportation and storage[6]	222	217	181	162	158	860	1,800
Commodity purchases[7]	49	48	57	47	38	122	361
Other[8]	354	40	14	6	14	1	429
Total contractual obligations	$4,343	$3,534	$3,552	$2,585	$2,229	$30,191	$46,434

(1) See Item 8, Financial Statements and Supplementary Data, Note 20.

(2) See Item 8, Financial Statements and Supplementary Data, Note 6. As of December 31, 2003, we held deposits of $468 million in an escrow account to fund a portion this obligation. In June 2004, we paid approximately $602 million related to the obligation.

(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 $65 million in 2004 and $229 million for the four year period ended December 31, 2008, because these expected contributions are not contractually required.

(4) See Item 8, Financial Statements and Supplementary Data, Note 22.

(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 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.

The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2003:

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	$ 27	$ 40	$ —	$ —	$ —	$ 67
Liabilities	(27)	(51)	(10)	(10)	—	(98)
Total derivatives designated as hedges	—	(11)	(10)	(10)	—	(31)
Assets from power contract restructuring derivatives(1)	227	454	407	695	142	1,925
Other commodity-based derivatives						
Exchange-traded positions(2)						
Assets	117	20	42	—	—	179
Liabilities	(105)	(17)	—	—	—	(122)
Non-exchange traded positions						
Assets	356	268	125	155	36	940
Liabilities(1)	(623)	(431)	(182)	(209)	(40)	(1,485)
Total other commodity-based derivatives	(255)	(160)	(15)	(54)	(4)	(488)
Total commodity-based derivatives	$ (28)	$ 283	$ 382	$ 631	$138	$ 1,406

(1) Includes $189 million of intercompany derivatives that eliminate in consolidation, and have no impact on our consolidated assets and liabilities from price risk management activities. During 2004, we have sold power contract derivatives representing $942 million of the total assets from power contract restructuring derivatives as of December 31, 2003.

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

Below is a reconciliation of our commodity-based derivatives for the years ended December 31, 2003 and 2002. These amounts reflect the restatement of derivatives historically accounted for as hedges that have been determined to not qualify for hedge accounting. In August 2004, we determined we had incorrectly accounted for certain of our historical hedges, primarily associated with our natural gas production. See Item 8, Financial Statements and Supplementary Data, Note 1 for a discussion of this restatement.

	Derivatives Designated as Hedges (Restated)	Derivatives from Power Contract Restructuring Activities	Other Commodity-Based Derivatives (Restated)	Total Commodity-Based Derivatives (Restated)
		(In millions)		
Fair value of contracts outstanding at December 31, 2001	$ 153	$ —	$ 1,605	$ 1,758
Cumulative effect of accounting change for EITF Issue No. 02-3	—	—	(343)	(343)
Inventory-related reclassifications as a result of EITF Issue No. 02-3	—	—	(254)	(254)
Fair value of contract settlements during the period	(64)	(45)	(413)	(522)
Initially recorded value of new contracts	—	1,004	84	1,088
Change in fair value of contracts	(110)	9	(1,214)	(1,315)
Other	—	—	10	10
Net change in contracts outstanding during the period	(174)	968	(2,130)	(1,336)
Fair value of contracts outstanding at December 31, 2002	(21)	968	(525)	422
Fair value of contract settlements during the period	15	(405)	471	81
Change in fair value of contracts	(25)	140	(346)	(231)
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

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 initially recorded value of new contracts includes the fair value of origination transactions at the inception of the transaction. In 2002, the initially recorded value of new contracts includes a $59 million gain related to the completion of our Snøhvit LNG supply contract in our other commodity-based derivatives and a $898 million gain related to our Eagle Point power contract restructuring transaction.

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 or, if not settled, until the end of the period.

During 2003, in conjunction with our acquisition of Chaparral, we consolidated derivative contracts that had a fair value of approximately $1.2 billion on the date acquired. 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.

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, resolving substantial contingences and returning to our core natural gas businesses. Accordingly, our operating results during this three year period 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.

In February 2004, we completed the December 31, 2003 reserve estimation process for our proved natural gas and oil reserve estimates. The results of this process indicated that a 1.8 Tcfe downward revision in our proved reserves was needed. After an investigation into the factors that caused this revision, we determined that a material portion of these reserve revisions should be reflected in the historical periods in this Annual Report on Form 10-K. In August 2004, we also determined that we had not properly applied the accounting related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. Following an investigation into this matter, we concluded that our historical financial statements should be further restated. Accordingly, our historical financial results for 1999 through 2002 and for the first three quarters of 2003 were restated for these matters. See Item 8, Financial Statements and Supplementary Data, Note 1, for a further discussion of these restatements.

As of December 31, 2003, our operating business segments were Pipelines, Production, Field Services and Merchant Energy. These segments provide a variety of energy products and services. They are managed separately and each requires different technology, operational and marketing strategies. Under our Long-Range Plan announced in December 2003, our businesses will be divided into two primary business lines: regulated and unregulated. Our regulated business will include our existing Pipelines segment, while our unregulated business will include our existing Production, Field Services and Merchant Energy 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 without regard to 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:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Regulated Business			
Pipelines	$ 1,234	$ 816	$ 1,032
Unregulated Businesses			
Production	962	703	(1,068)
Field Services	133	289	196
Merchant Energy	(1,001)	(2,018)	2,157
Segment EBIT	1,328	(210)	2,317
Corporate and other	(689)	(321)	(1,429)
Consolidated EBIT	$ 639	$ (531)	$ 888
Interest and debt expense	(1,787)	(1,293)	(1,129)
Distributions on preferred interests of consolidated subsidiaries	(52)	(159)	(217)
Income taxes	584	649	70
Loss from continuing operations	(616)	(1,334)	(388)
Discontinued operations, net of income taxes	(1,303)	(365)	(85)
Extraordinary items, net of income taxes	—	—	26
Cumulative effect of accounting changes, net of income taxes	(9)	(54)	—
Net loss	$(1,928)	$(1,753)	$ (447)

Our earnings in each period were impacted both favorably and unfavorably by a number of factors affecting our businesses that are enumerated in the table below. The discussion that follows summarizes these factors and their impact on our operating segments and our corporate and other operations. For a more detailed discussion of these factors and other items impacting our financial performance, see the individual segment and other results included in Item 8, Financial Statements and Supplementary Data, Notes 5 through 10, and 28.

	Operating Segments				
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other
			(In millions)		
2003					
Asset and investment impairments, net of gain(loss) on sale[(1)]	$ 9	$ (94)	$ 9	$(635)	$ (412)
Ceiling test charges	—	(76)	—	—	—
Restructuring charges	(2)	(6)	(4)	(70)	(42)
Western Energy Settlement[(2)]	(140)	—	—	(26)	(4)
Total	$(133)	$ (176)	$ 5	$(731)	$ (458)
2002					
Asset and investment impairments, net of gain(loss) on sale[(1)]	$(137)	$ (3)	$ 129	$(686)	$ (168)
Ceiling test charges	—	(128)	—	—	—
Restructuring charges	(1)	—	(1)	(24)	(51)
Western Energy Settlement	(412)	—	—	(487)	—
Net gain on power contract restructurings	—	—	—	578	—
Total	$(550)	$ (131)	$ 128	$(619)	$ (219)
2001					
Coastal merger and related charges[(3)]	$(309)	$ (58)	$ (54)	$ (17)	$(1,237)
Asset and investment impairments, net of gain(loss) on sale[(1)]	(25)	(16)	21	(94)	(75)
Ceiling test charges	—	(2,143)	—	—	—
Net gain on power contract restructurings	—	—	—	31	—
Total	$(334)	$(2,217)	$ (33)	$ (80)	$(1,312)

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

(2) Includes $51 million of accretion expense and $15 million of other charges included in operation and maintenance expense associated with the Western Energy Settlement.

(3) Includes $182 million of charges related to changes in accounting estimates in 2001 associated with additional environmental remediation liabilities, accrued legal obligations and usability of spare parts inventories.

As indicated in the tables above, our EBIT during the past three years has been impacted by a number of significant developments and events in our business and industry. In addition to the items described above, two of our operating segments have experienced significant earnings volatility during this period. Much of this volatility occurred in our Merchant Energy segment. Beginning in 2002, Merchant Energy began a process of exiting its trading business. At the same time, the overall energy trading industry declined following the financial collapse of Enron in late 2001. The combination of these actions and events resulted in substantial losses in Merchant Energy in 2002 and 2003 compared with 2001. We expect that this segment will continue to experience losses in 2004 as it continues the liquidation of its trading business.

Our Production segment also experienced earnings volatility from 2001 to 2003 and in 2003 benefited from a favorable pricing environment that allowed for improved results. However, during that three-year period, our Production segment sold a significant number of natural gas and oil properties which, coupled with generally disappointing drilling results and mechanical failures on certain wells, produced a steady decline in production volumes during that timeframe. The favorable pricing environment will continue to provide benefits to the segment during 2004, although its future results will largely be impacted by its ability to grow its existing reserve base through a successful drilling program and/or acquisitions.

Finally, during 2001, 2002 and 2003, we incurred approximately $1.8 billion (including $1.4 billion during 2003) in pretax losses in exiting our petroleum markets, coal and chemicals 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, interest and debt expense, distributions on preferred interests of consolidated subsidiaries, income taxes and the results of our discontinued operations.

Individual Segment Results

The results for 2002 and 2001, as well as for the nine months ended September 30, 2003 of our Pipelines, Production and Merchant Energy segments presented and discussed below have been restated for adjustments to our natural gas reserve estimates and for the manner in which we accounted for many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. See Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatements and the manner in which our segments were affected. In addition the Merchant Energy segment has been restated to reflect the reclassification of our historical coal mining and petroleum markets businesses as discontinued operations.

Regulated Businesses — Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage and related services, primarily in the U.S. Our interstate natural gas transportation systems face varying degrees of competition from other pipelines, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil. In addition, 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 has impacted the volatility of our revenues, and 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 markets in power plants.

We are regulated by the FERC, which regulates the rates we can charge our customers. These rates are a function of the costs 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, they can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the credit-worthiness of our customers. 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. In addition, the FERC has issued various orders related to the allocation of capacity on the EPNG system, one of our pipeline systems. These orders impacted our 2003 Pipeline segment revenues and will continue to impact its future results. In addition, we expect lower annual revenues of approximately $22 million due to the expiration of certain other risk sharing provisions on the EPNG system.

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	2003	2002 (Restated)	2001 (Restated)
	(In millions, except volume amounts)		
Operating revenues[1]	$ 2,647	$ 2,610	$ 2,742
Operating expenses[1]	(1,584)	(1,822)	(1,862)
Operating income	1,063	788	880
Other income	171	28	152
EBIT	$ 1,234	$ 816	$ 1,032
Throughput volumes (BBtu/d)[2]			
TGP	4,710	4,596	4,405
EPNG and MPC	4,066	4,065	4,536
ANR	4,232	4,130	4,531
CIG and WIC	2,743	2,768	2,466
SNG	2,101	2,151	2,027
Equity investments (our ownership share)	2,463	2,496	2,226
Total throughput	20,315	20,206	20,191

(1) Within our revenues and operating expenses are amounts recorded under a number of natural gas purchase and sale agreements. These contracts are based on market prices and impact our revenues and operating expenses with little impact on operating income or EBIT. For the years ended December 31, 2003, 2002 and 2001, revenues on these contracts were $70 million, $56 million and $91 million, and operating expenses were $68 million, $53 million and $90 million.

(2) Throughput volumes excludes volumes related to our equity investments in the Alliance Pipeline and Portland Natural Gas Transmission systems which were sold. Throughput volumes exclude intrasegment activities. Prior period volumes have been restated to reflect current year presentation which includes billable transportation throughput volume for storage injection and withdrawal.

Our segment results have been restated in 2002 and 2001 to reflect adjustments for non-qualifying cash flow hedges of production owned by CIG. For a further discussion of the restatement, see Item 8, Financial Statements and Supplementary Data, Note 1.

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

For the year ended December 31, 2003, our EBIT was $418 million higher than in 2002. Reduced operating expenses of $238 million, higher non-operating income of $143 million and improved revenues of $37 million in 2003 contributed to our improved EBIT performance.

Our 2003 operating expense reductions resulted primarily from the impact of the Western Energy Settlement reached in 2003. 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 would pay 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. Year over year, the difference in recorded charges on the Western Energy Settlement resulted in a positive operating expense impact of $272 million.

The $143 million increase in other income resulted primarily from impairment charges in 2002 related to our equity investment in EPIC Energy Australia Trust (EPIC). In 2002, we recorded impairments of our Australian investment of $153 million 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. Partially offsetting these impairment charges were lower equity earnings of $20 million from our investment in the Alliance Pipeline, which we sold in the first quarter of 2003.

Our 2003 EBIT was also favorably impacted by our re-application of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* by our CIG and WIC systems, resulting in an $18 million one-time increase in other income. This income resulted 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 this 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 will result in depreciation expense increases in the future of approximately $9 million annually. Based on our estimates, we anticipate that the overall annual EBIT impact as a result of our re-application of SFAS No. 71 will be an annual reduction of EBIT of approximately $10 million.

The $37 million increase in our revenues was the result of a number of revenue items, the more significant of which are discussed below. In 2003, we experienced higher revenues of $57 million due to higher volumes and prices on natural gas retained on our regulated systems in excess of amounts we used in our pipeline operations. In addition, completed system expansions and new transportation contracts increased revenues by $41 million, which, when considering the operating expense impact of these expansions, increased EBIT by $37 million. Offsetting these revenue increases was the impact of expiring capacity contracts which EPNG was prohibited from remarketing due to the FERC orders and other capacity that EPNG was required to make available to its former full requirements (FR) customers related to its Line 2000 Power-up project. The impact of these orders was a decrease in revenues of $35 million. With the completion of Phases I and II of its Line 2000 Power-up project in February and April of 2004, EPNG's requirement to dedicate capacity to its FR customers was terminated. Also contributing to lower revenues was CIG's sale of its Panhandle field and other production properties in July 2002, which reduced revenues by $50 million and, when considering related operating expense reductions, resulted in an EBIT decline of $29 million.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Our EBIT for 2002 decreased $216 million from 2001. This decrease primarily resulted from a $153 million impairment charge recorded in other income on our investment in Australia and a $99 million increase in 2002 in operating expenses. These operating expenses included a $412 million charge in 2002 associated with our Western Energy Settlement and $313 million of merger related and asset impairment charges in 2001 related to our merger with Coastal. Also impacting the EBIT decrease were $49 million of lower revenues from capacity sold under short-term contracts and lower throughput from reduced electric demand and milder weather in our market areas, a $59 million decrease in revenues from lower natural gas prices which impacts the income we recognize from natural gas recovered under our tariffs in excess of the amounts used in our pipeline operations, and a $49 million reduction in revenues and a $27 million decrease in EBIT as a result of CIG's sale of its Panhandle field in July 2002. Partially offsetting these EBIT reductions were $27 million of lower general, administrative and operating costs as a result of cost efficiencies achieved following the Coastal merger, $49 million of other operating cost reductions due to lower electrical prices, natural gas imbalance pricing changes and lower allocated overhead, environmental and legal costs. Further offsetting these EBIT reductions were the favorable impact of system expansions completed in 2001 and 2002 as well as a full year of operations at our Elba Island LNG facility, which increased revenues by $83 million, operating expenses by $33 million and EBIT by $50 million.

Unregulated Businesses — Production Segment

Our Production segment results have been restated for revisions to our natural gas and oil reserve estimates and for our accounting for many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. 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 and sell the products at attractive prices. Consistent with our Long-Range Plan announced in December 2003, our long-term strategy includes developing our production opportunities primarily in the U.S. and Brazil, while prudently divesting of production properties outside of these regions. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia. Our operations in Canada included activities in Nova Scotia where, in the first quarter of 2004, we drilled an exploratory well that was not commercially viable and recorded a $24 million ceiling test charge. Also in 2004, we acquired the remaining 50 percent interest in our investment in UnoPaso to increase our production operations in Brazil.

In June 2004, we announced a back-to-basics plan for our production business. This plan emphasizes strict capital discipline designed to improve capital efficiency through the use of standardized risk analysis, a heightened focus on cost control, and revised controls for booking proved natural gas and oil reserves. This back-to-basics approach is expected to stabilize production by improving the production mix across our operating areas and generate more predictable returns.

Reserves and Costs

In February 2004, we completed our estimates of our proved natural gas and oil reserves as of December 31, 2003. These estimates were prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates of our proved reserves for 90 percent and 10 percent of our properties. The total estimate of proved reserves prepared by these engineers is within five percent of our internally prepared estimates.

The proved reserve estimate as of December 31, 2003 indicated a 1.8 Tcfe downward revision of our proved natural gas and oil reserves was needed. The downward revisions related primarily to our Coal Seam, Texas onshore and offshore Gulf of Mexico regions. Due to the significance of the reserve revision, the Audit Committee of the Board of Directors engaged a law firm to conduct an independent investigation into the reasons for the revisions. The investigation concluded that a material portion of these revisions related to prior periods, and as a result we have restated our historical reserve estimates and our historical financial information derived from these estimates. The reserve restatement involved utilizing the reserve estimate prepared as of December 31, 2003 and then reconstructing historical reserve data using actual historical production data and re-engineered sales of proved reserves. Following this reserve reconstruction and the recalculation of the discounted future net cash flows, ceiling test calculations, depletion rates, and gains and losses on asset sales were recomputed for each period restated. See Item 8, Financial Statements and Supplementary Data, Notes 1, 9 and 30 for a discussion of our ceiling test calculation and the restatement of our natural gas and oil reserves. The restatement will result in a lower depletion rate and reduced exposure to ceiling test charges in the future than would have been the case absent the restatement.

Since December 31, 2001, we have sold approximately 1.3 Tcfe of proved reserves in multiple sales transactions with various third parties. The sale of these reserves, combined with the normal production declines, mechanical failures on certain producing wells and disappointing drilling results, have resulted in our total equivalent production levels declining each quarter since the first quarter of 2002. For 2003, our total equivalent production has declined approximately 165 Bcfe or 28 percent as compared to 2002. In addition, since our depletion rate is determined under the full cost method of accounting, we expect a higher depletion rate as a result of higher finding and development costs experienced this year, coupled with a significantly lower reserve base. After taking into consideration the restatement of our natural gas and oil reserves for prior periods and the impacts on our restatement of production and other hedges discussed above, our unit of production depletion rate was approximately $1.58 per Mcfe and $1.64 per Mcfe for the first and second quarters of 2004. We expect this rate to be approximately $1.74 per Mcfe for the third quarter of 2004. See

Item 8, Financial Statements and Supplementary Data, Note 30, for a discussion of our natural gas and oil reserves. For the first eight months of 2004, daily production has averaged approximately 855 MMcfe/d; however, for the month of August 2004, daily production averaged approximately 810 MMcfe/d. Our future trends in production and our depreciation, depletion and amortization rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and future sales activities relating to our proved reserves.

Production Hedging

We have historically hedged a portion of our anticipated natural gas production by entering into affiliated hedge transactions with our Merchant Energy segment, which would then enter into identical transactions with third parties to complete the hedge. During August 2004, we determined that we had not properly applied the accounting rules related to many of the historical hedges of our anticipated natural gas production. Specifically, we determined that many of the hedges put in place by Merchant Energy did not qualify as hedges for consolidated reporting purposes, as, in many cases, Merchant Energy had entered into an offsetting trading transaction. Consequently, we restated our accounting for these hedges and have not reflected these transactions as hedges in our segment results or the information presented below.

We primarily conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production to stabilize cash flows and reduce the risk of downward commodity price movements on our sales. 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. During 2003, we did not add additional hedges on our future production. Below are the hedging positions on our anticipated natural gas production as of December 31, 2003:

	Quarters Ended									
	March 31		June 30		September 30		December 31		Total	
	Volume (BBtu)	Hedged Price	Volume (BBtu)	Hedged Price	Volume (BBtu)	Hedged Price	Volume (BBtu)	Hedged Price	Volume (BBtu)	Hedged Price
2004	1,142	$2.32	1,142	$2.32	1,155	$2.97	1,154	$2.97	4,593	$2.64
2005	1,130	$2.97	1,142	$2.97	1,155	$3.09	1,154	$3.09	4,581	$3.03
2006	1,130	$3.09	1,142	$3.09	1,155	$3.22	1,154	$3.22	4,581	$3.15
2007 and beyond									25,200	$3.60

In May 2004, we entered into the following additional hedges on our future natural gas production:

	Volume (BBtu)	Hedged Price
June 2004 – December 2004	1,070	$6.33
2005	1,825	$5.78
2006	1,825	$5.28
January 2007 – May 2007	755	$5.23
	5,475	

In August 2004, we entered into the following hedges on our future oil production in Brazil:

	Volume (MBbls)	Hedged Price
August 2004 – December 2004	161	$35.15
2005	383	$35.15
2006	383	$35.15
2007	192	$35.15
	1,119	

Operating Results

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

Production Segment Results	2003	2002 (Restated) [1]	2001 (Restated) [1]
	(In millions, except volumes and prices)		
Operating revenues:			
Natural gas	$ 1,906	$ 1,622	$ 2,139
Oil, condensate and liquids	314	373	326
Other	9	8	21
Total operating revenues	2,229	2,003	2,486
Transportation and net product costs	(96)	(113)	(97)
Total operating margin	2,133	1,890	2,389
Depreciation, depletion and amortization	(606)	(622)	(797)
Production costs[2]	(239)	(304)	(336)
Ceiling test and other charges[3]	(176)	(131)	(2,217)
General and administrative expenses	(162)	(127)	(95)
Taxes, other than production and income taxes	(6)	(8)	(13)
Total operating expenses[4]	(1,189)	(1,192)	(3,458)
Operating income (loss)	944	698	(1,069)
Other income	18	5	1
EBIT	$ 962	$ 703	$ (1,068)
Volumes, prices and cost per unit:			
Natural gas			
Volumes (MMcf)	354,298	486,923	564,740
Average realized prices including hedges ($/Mcf)[5]	$ 5.38	$ 3.33	$ 3.79
Average realized prices excluding hedges ($/Mcf)[5]	$ 5.48	$ 3.16	$ 4.23
Average transportation costs ($/Mcf)	$ 0.21	$ 0.18	$ 0.12
Oil, condensate and liquids			
Volumes (MBbls)	12,087	17,514	14,382
Average realized prices including hedges ($/Bbl)[5]	$ 26.02	$ 21.30	$ 22.66
Average realized prices excluding hedges ($/Bbl)[5]	$ 26.69	$ 21.39	$ 22.87
Average transportation cost ($/Bbl)	$ 1.05	$ 0.93	$ 0.56
Production cost ($/Mcfe)			
Average lease operating cost	$ 0.42	$ 0.43	$ 0.38
Average production taxes	0.14	0.08	0.14
Total production cost	$ 0.56	$ 0.51	$ 0.52
Average general and administrative cost ($/Mcfe)	$ 0.38	$ 0.21	$ 0.15
Unit of production depletion cost ($/Mcfe)	$ 1.32	$ 1.02	$ 1.20

(1) Amounts restated include operating revenues, depreciation, depletion, and amortization and ceiling test and other charges as well as related subtotals and totals. Additionally, average realized prices including hedges and unit of production depletion costs have been restated.

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

(3) Includes ceiling test charges, restructuring and merger-related costs, asset impairments, gain (loss) on long-lived assets and changes in accounting estimates.

(4) Transportation costs are included in operating expenses on our consolidated statements of income.

(5) Prices are stated before transportation costs.

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

For the year ended December 31, 2003, EBIT was $259 million higher than in 2002. The increase was primarily due to higher revenues resulting from higher realized natural gas prices, partially offset by lower production volumes as a result of asset sales, normal production declines and disappointing drilling results.

Operating Revenues. The following table describes the variance in revenue between 2003 and 2002 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges on our revenues.

Production Revenue Variance Analysis	Variance Prices	Variance Volumes	Variance Hedges	Variance Total
	(In millions)			
Natural gas	$822	$(419)	$(119)	$ 284
Oil, condensate and liquids	64	(116)	(7)	(59)
Other	—	—	—	1
Operating revenue variance	$886	$(535)	$(126)	$ 226

Our 2003 operating revenues increased $226 million as compared to 2002 primarily due to higher market prices for natural gas and oil offset by lower production volumes and an unfavorable impact from our hedging program. The decline in our natural gas volumes was due to the sale of properties in New Mexico, Oklahoma, Texas, Utah, offshore Gulf of Mexico and western Canada, normal production declines, mechanical failures in several of our producing wells and disappointing drilling results. Our production declines and mechanical failures were primarily in our Texas onshore and offshore Gulf of Mexico regions. Our 2003 oil, condensate and liquids volume declines were also primarily due to asset sales, and production declines and mechanical failures in certain producing wells in our offshore Gulf of Mexico region.

Average realized natural gas prices in 2003, excluding hedges, were $2.32 per Mcf higher than in 2002, an increase of 73 percent. However, partially offsetting the revenue increase were $36 million of hedging losses in 2003 as compared to $83 million of hedging gains in 2002 relating to our natural gas hedge positions. These hedging losses and gains represent the difference between our hedge price and the market price at the time the hedge positions were settled. We expect to continue to incur hedge losses in 2004 based on current market prices for natural gas relative to the prices at which our natural gas production is hedged.

Operating Expenses. Total operating expenses were $3 million lower in 2003 as compared to 2002 primarily due to a lower depreciation, depletion and amortization expenses as a result of asset sales and lower production costs, offset by higher ceiling test and other charges and general and administrative costs.

Total depreciation, depletion, and amortization expense decreased by $16 million in 2003 as compared to 2002 primarily due to lower production volumes partially offset by higher unit of production depletion rates. Lower production volumes in 2003 due to the asset sales, normal production declines and mechanical failures discussed above reduced our depreciation, depletion and amortization expenses by $168 million. Partially offsetting lower production volumes were higher depletion rates that contributed an increase of $130 million in our depreciation, depletion, and amortization expense. The higher depletion rate was due to higher finding and development costs in 2003 as a result of disappointing drilling results and a lower reserve base due to asset sales. Also offsetting the overall decrease in 2003 was $23 million incurred in 2003 for the accretion of our liability for asset retirement obligations.

Production costs decreased by $65 million in 2003 as compared to 2002 due to the asset sales discussed above. However, our production cost per equivalent unit in 2003 increased by 10 percent or $0.05 per Mcfe primarily as a result of higher production taxes in 2003 due to higher natural gas and oil prices and higher tax credits taken in 2002 on high cost natural gas wells.

Ceiling test and other charges increased by $45 million in 2003, compared to 2002. In 2003, we incurred $76 million in non-cash full cost ceiling test charges for our Canadian full cost pool and other international properties, primarily in Brazil and Australia, and a $75 million impairment of the goodwill associated with our Canadian operations. Also in 2003 we recorded $18 million in asset impairments net of gains on non-full cost pool asset sales, and $6 million in restructuring costs. In 2002, we recorded non-cash full cost ceiling test charges of $128 million related to our Canadian full cost pool and other international properties, primarily in Brazil, Indonesia, Turkey and Australia.

General and administrative expenses were $35 million higher than in 2002, or an increase of $0.17 per Mcfe. The increase was primarily due to higher corporate overhead allocations and lower capitalized costs. Also contributing to the per unit increase were lower production volumes due to asset sales discussed above. Our total general and administrative expenses have decreased primarily due to staff reductions in the first quarter of 2004. Additionally, El Paso announced plans to reduce its corporate expenses as part of its Long-Range Plan, which is expected to reduce our corporate overhead allocations.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

For the year ended December 31, 2002, EBIT was $1.8 billion higher than in 2001. The increase was primarily due to lower operating expenses in 2002 from lower ceiling test and other charges, partially offset by the impacts of lower natural gas prices and lower natural gas volumes due to asset sales.

Operating Revenues. The following table describes the variance in revenue between 2002 and 2001 due to: (i) changes in average realized market prices excluding hedges, (ii) changes in production volumes, and (iii) the effects of hedges on our revenues.

	Variance			
Production Revenue Variance Analysis	**Prices**	**Volumes**	**Hedges**	**Total**
	(In millions)			
Natural gas	$(519)	$(328)	$330	$(517)
Oil, condensate and liquids	(26)	72	1	47
Other	—	—	—	(13)
Operating revenue variance	$(545)	$(256)	$331	$(483)

Our 2002 operating revenues decreased by $483 million as compared to 2001 primarily due to lower natural gas prices and lower production volumes. The decline in our natural gas volumes was primarily due to the sale of properties in Colorado, Utah, and Texas.

Average realized natural gas prices in 2002, excluding hedges, were $1.07 per Mcf lower than in 2001, a decrease of 25 percent. Partially offsetting these reductions were $83 million of hedging gains in 2002 versus $247 million of hedging losses in 2001 relating to our natural gas hedge positions. These hedge losses and gains represent the difference between our hedge price and the market price at the time the hedge positions were settled.

Operating Expenses. Total operating expenses were $2.3 billion lower in 2002 as compared to 2001 primarily due to lower non-cash full cost ceiling test and other charges and depreciation, depletion and amortization expense.

Ceiling test and other charges for the year ended December 31, 2002, were $2.1 billion lower than in 2001. In 2002, we incurred $128 million in non-cash full cost ceiling test charges for our Canadian full cost pool and other international properties, primarily in Brazil, Indonesia, Turkey and Australia, as compared to charges of $2.1 billion in 2001 on our domestic and international properties, primarily in Canada, Brazil, Indonesia and Turkey. In addition, in 2001, we incurred merger-related and other costs of $73 million related to combining our production operations following the Coastal merger.

Total depreciation, depletion and amortization expense decreased in 2002 by $175 million as compared to 2001 primarily due to lower production volumes as a result of asset sales, and lower unit of production depletion rates. The lower production volumes in 2002 reduced our depreciation, depletion and amortization expense by $71 million and the lower depletion rates contributed to a decrease of $106 million.

Production costs decreased by $32 million in 2002 as compared to 2001 primarily due to lower production volumes as a result of the asset sales mentioned above. However, our production costs per equivalent unit were relatively flat in 2002 as compared to 2001. A decrease of 43 percent, or $0.06 per Mcfe, in production taxes was largely offset by an increase in lease operating costs of $0.05 per Mcfe due to higher labor and workover expenses. Lower production taxes were primarily due to lower natural gas and oil prices and tax credits taken in 2002 related to high cost natural gas wells.

General and administrative expenses increased by $32 million from 2001, or an increase of $0.06 per Mcfe primarily due to higher corporate overhead allocations and lower production volumes.

Unregulated Businesses — Field Services Segment

Our Field Services segment conducts our midstream activities which include gathering and processing of natural gas. For the majority of 2003, our assets principally consisted of our general and limited partner holdings of GulfTerra, a publicly traded master limited partnership in which our subsidiary serves as the general partner and our consolidated processing assets in south Texas and south Louisiana. For a discussion of our ownership interests in GulfTerra and our activities with the partnership, see Item 8, Financial Statements and Supplementary Data, Note 28. Prior to 2003, our Field Services segment owned gathering, processing and fractionation assets.

Investment in GulfTerra

We recognize earnings and receive cash from GulfTerra in several ways, including through a share of the partnership's cash distributions and through our ownership of limited, preferred and general partner interests. During 2003, the primary source of earnings in our Field Services segment was from our equity investment in GulfTerra. Our sale of an effective 50 percent interest in GulfTerra's general partner in December 2003 as well as the expected completion of the sale in 2004 of our remaining interest in the general partner of GulfTerra (upon which we will receive cash and a 9.9 percent interest in the general partner of GulfTerra and Enterprise) will result in lower equity earnings in 2004. We also receive management fees under an agreement to provide operational and administrative services to the partnership. These management fees have increased as a result of GulfTerra's asset acquisitions in 2002 and 2003, but will terminate at the time of the merger of GulfTerra and Enterprise. In addition, we are reimbursed for costs paid directly by us on the partnership's behalf. For the years ended December 31, 2003 and 2002 and 2001, we were reimbursed approximately $91 million, $60 million, and $33 million for expenses incurred on behalf of the partnership. During 2003, our equity investment earnings and cash distributions received from GulfTerra were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner's share of distributions	$ 70	$ 70
Proportionate share of income available to common unit holders	17	32
Series B preference units	12	—
Series C units	16	30
Gains on issuance by GulfTerra of its common units	38	—
	$153	$132

In addition to our equity investment earnings above, we realized other income and losses in the fourth quarter of 2003 related to our investment in GulfTerra as follows:

- a realized loss of $11 million on the redemption by GulfTerra of all of our Series B units for total proceeds of $156 million;
- a realized gain of $8 million related to our sale of GulfTerra common units; and
- a net realized gain of $269 million related to the sale of our effective 50 percent interest in the general partner to Enterprise for net proceeds of $421 million as discussed below.

The sale of one-half of our general partner interest to Enterprise was the first step in a series of transactions in which GulfTerra will merge with Enterprise to form one of the largest energy master limited partnerships in the U.S. The merger and related transactions, which are discussed more fully in Item 8, Financial Statements and Supplementary Data, Note 28, are subject to customary approvals and is expected to be completed in the third quarter of 2004.

From 2001 to 2003, we entered into a number of asset sales transactions with GulfTerra. In 2003, we exchanged communications assets for a release of our obligation to repurchase the Chaco cryogenic natural gas processing plant in 2021. We recognized a net gain on this transaction of $67 million. In 2002, we sold assets to GulfTerra for total proceeds of $1.5 billion, including gathering, processing and transmission assets and substantially all our assets in the San Juan Basin. Total net gains recognized on the assets sold in 2002 were approximately $210 million. In 2001, we sold assets to GulfTerra for total proceeds of $255 million, including processing and NGL transportation and fractionation assets, as well as an investment in Deepwater Holdings, an entity that owned several pipeline gathering systems in the Gulf of Mexico. The majority of these assets had been acquired by us one year earlier in a purchase transaction and accordingly had been recorded at their fair value. As a result, these sales resulted in no gains or losses. In conjunction with the 2002 sales, we agreed to reimburse GulfTerra for a portion of its future pipeline integrity costs related to these assets through 2006. At the time of these sales, we were unable to estimate the liability associated with this obligation as we and GulfTerra were in the early stages of our pipeline integrity programs. In December 2003, we amended this agreement to clarify the types and amounts of reimbursable costs, and also began reviewing GulfTerra's pipeline integrity results. This review has continued during 2004. Based on those results, and on our experience to date related to our own pipeline integrity projects, we determined that the obligation was both probable and could be estimated. As a result, we recognized a $74 million loss on this agreement in 2003.

Other Asset Sales

In addition to the sales to GulfTerra discussed above, during 2003 we sold our gathering systems located in Wyoming to Western Gas Resources, Inc. We also sold our midstream assets in the Mid-Continent and north Louisiana regions to Regency Gas Services LLC, an investment of Charlesbank Capital Partners, LLC. Our Mid-Continent assets primarily included our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. Our north Louisiana assets primarily included our Dubach processing plant and Gulf States interstate natural gas transmission system.

Gathering and Processing Operations

By the end of 2003, our remaining gathering and processing assets consisted primarily of south Texas gathering and processing assets and south Louisiana processing assets. Our south Texas processing plants will be sold to Enterprise in 2004 as part of the merger between Enterprise and GulfTerra. At that point, most of our gathering and processing business will be conducted through our ownership interests in the merged partnership.

We attempt to balance earnings in our gathering and processing business through a combination of fixed fee-based and market-based services. A majority of our gathering operations earn margins from fixed fee-based services. However, some of these operations earn margins from market-based rates. Revenues from these market-based rate services are the product of the market price, usually related to the monthly natural gas price index and the volume gathered. Our processing operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for the service provided. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, we may have more sensitivity to price changes during periods when natural gas and NGL prices are volatile.

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

Field Services Segment Results	2003	2002	2001
	(In millions, except volumes and prices)		
Gathering and processing gross margins[1]	$ 132	$ 349	$ 561
Operating expenses	(325)	(76)	(437)
Operating income (loss)	(193)	273	124
Other income	326	16	72
EBIT	$ 133	$ 289	$ 196
Volumes and Prices:			
Gathering			
Volumes (BBtu/d)	357	3,023	6,109
Prices ($/MMBtu)	$ 0.18	$ 0.17	$ 0.14
Processing			
Volumes (inlet BBtu/d)	3,206	3,920	4,360
Prices ($/MMBtu)	$ 0.10	$ 0.10	$ 0.15

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

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

For the year ended December 31, 2003, our EBIT was $156 million lower than 2002. Our asset sales in 2003 and 2002 contributed a year over year decrease in our EBIT of $119 million. We also had $191 million of additional impairments in 2003 compared to 2002. Throughout 2003, natural gas prices were higher relative to NGL prices, which further reduced EBIT at our processing plants by $11 million. Partially offsetting these declines were $71 million of year over year net gains realized on the sale of assets in 2003 and 2002, as well as higher equity earnings of $83 million from our investment in GulfTerra.

The decrease in our gathering and processing gross margins was primarily the combined result of asset sales and the impact of higher natural gas prices relative to NGL prices. Our asset sales decreased 2003 gathering margins by $154 million and our 2003 processing margins by $46 million. On our processing and gathering assets, we experienced higher natural gas prices during 2003 which reduced our margin per unit at these plants and also minimized the amount of NGLs extracted, both resulting in lower realized margins and EBIT in 2003 of $11 million.

Our higher operating expenses in 2003 were the result of a $74 million loss related to our pipeline integrity agreement with GulfTerra in 2003, impairments on our south Texas gathering and processing assets based on our planned sale of these assets to Enterprise along with an impairment on our Altonah processing facility both of which totaled $171 million in 2003, compared with $66 million of impairments in 2002 on our north Louisiana facilities resulting from the decision to sell those facilities. We also realized net gains on sales of assets of $74 million in 2003 compared with $245 million in 2002. The increase in impairments in 2003 and higher realized gains in 2002 resulted in a year over year increase in operating expenses of $276 million. Partially offsetting these increases were higher reimbursements from GulfTerra of $17 million for administrative and other services and lower operating expenses of $81 million related to asset sales.

The $310 million increase in other income was primarily due to the $269 million net gain on our sale of an effective 50 percent interest in the general partner of GulfTerra to Enterprise, as well as an increase in earnings from our investment in the partnership of $83 million in 2003. Also contributing to the year over year increase was a loss in 2002 on our investment in the Aux Sable NGL plant and our Black Forks natural gas processing plant of $50 million and a gain of $8 million on the sale of a portion of our interest in GulfTerra's common units in 2003. Partially offsetting these increases were impairments in 2003 on our investments in Dauphin Island Gathering Partners and Mobile Bay Processing Partners of $86 million and an $11 million loss on the redemption of our Series B units in GulfTerra.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

For the year ended December 31, 2002, our EBIT was $93 million higher than 2001. During 2002, lower margins of $134 million from the sales of midstream assets to GulfTerra along with a decrease in processing margins of $58 million due to lower NGL prices, were offset by lower 2002 operating costs of $361 million. In our operating expenses, we recognized a net gain in 2002 on the sales of our San Juan Basin assets, our Natural Buttes and Ouray systems and our Dragon Trail processing plant of $245 million. We also experienced lower operating costs in 2002 as a result of asset sales of $83 million and from the favorable impact on operating expenses from 2001 merger charges of $46 million incurred related to El Paso's merger with Coastal (see Item 8, Financial Statements and Supplementary Data, Note 5, for a discussion of these merger charges). Partially offsetting these lower operating costs were 2002 impairment charges of $66 million on our north Louisiana facilities.

During 2002, equity earnings from our investments were $54 million lower than 2001. The decrease was primarily due to $50 million of losses during 2002, on the sales of our investments in the Aux Sable NGL plant and our Black Forks natural gas processing plant.

Unregulated Businesses — Merchant Energy Segment

Our Merchant Energy segment consists of a Global Power division, an Energy Marketing and Trading division and a LNG division. Historically, it also had a petroleum markets division. In 2003, our Board of Directors approved the sale of these petroleum markets operations and, as a result, we reclassified that division as discontinued operations for all periods presented. The Energy Marketing and Trading division of the Merchant Energy segment has historically entered into transactions with third parties to accomplish hedges for the Production segment, for a subsidiary in our Pipelines segment and on its own behalf for capacity it held on natural gas pipelines. This division also conducted non-hedging transactions on its own behalf. In August 2004, we determined that we had not properly applied the accounting related to many of our historical hedges, primarily those associated with hedges of our anticipated natural gas production. As a result, we were required to restate our historical financial information to revise this accounting, which included the restatement of the historical financial statements of the Energy Marketing and Trading division. For a further discussion of this restatement, see Item 8, Financial Statements and Supplementary Data, Note 1. Below are the restated operating results and analysis of these results for our Merchant Energy segment for the three years ended December 31 (in millions):

Merchant Energy Segment Results	Global Power Division	Energy Marketing and Trading Division (Restated)	LNG Division	Eliminations	Total Merchant Energy Segment
			(In millions)		
2003					
Gross margin[1]	$ 886	$ (636)	$ —	$(58)	$ 192
Operating expenses	(879)	(183)	(177)	58	(1,181)
Operating income (loss)	7	(819)	(177)	—	(989)
Other income (expense)	(14)	10	(8)	—	(12)
EBIT	$ (7)	$ (809)	$(185)	$ —	$(1,001)
2002					
Gross margin[1]	$1,139	$(1,316)	$ (1)	$(35)	$ (213)
Operating expenses	(806)	(677)	(34)	35	(1,482)
Operating income (loss)	333	(1,993)	(35)	—	(1,695)
Other income (expense)	(339)	16	—	—	(323)
EBIT	$ (6)	$(1,977)	$ (35)	$ —	$(2,018)
2001					
Gross margin[1]	$ 421	$ 1,832	$ 2	$ —	$ 2,255
Operating expenses	(329)	(137)	(27)	—	(493)
Operating income (loss)	92	1,695	(25)	—	1,762
Other income (expense)	369	26	—	—	395
EBIT	$ 461	$ 1,721	$ (25)	$ —	$ 2,157

(1) Gross margin for our Global Power division 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. Gross margin for our energy marketing and trading division 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.

Global Power Division

Our Global Power division has three primary business activities: domestic power plant operations, domestic power contract restructuring activities and international power plant operations. Since December 31, 2003, we have sold a substantial portion of our domestic power plant operations and our domestic power contract restructuring activities for proceeds of approximately $537 million and the assumption by the buyer of approximately $926 million of debt. Each activity is further discussed below.

Below are the operating results of these activities within our Global Power division for the three years ended December 31. We have evaluated our operating results using EBIT due to several significant consolidations and transactions that affect year-to-year comparability and because our operations include both equity and consolidated investments.

Global Power Division Results	2003	2002	2001
		(In millions)	
Domestic Power			
Domestic power plant operations	$(383)	$ 80	$317
Domestic power contract restructuring business	150	341	31
International Power			
Brazilian power operations	177	78	114
Other international power operations	119	(246)	9
Other[1]	(70)	(259)	(10)
EBIT	$ (7)	$ (6)	$461

[1] Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance, and engineering costs and the effects of our financial services business and power turbine inventory on our operations. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations.

Domestic Power Plant Operations

Overview. Our domestic operations relate to the ownership and operation of power plant assets in the U.S. We own two types of domestic plants — contracted power operations and merchant power operations. Our contracted power operations include power plants that have dedicated power contracts with customers (generally electric utilities) for the generation and sale of power. Since the long-term sales contracts and long-term fuel contracts in these operations generally contain fixed prices, operating results in this business are fairly stable. However, some of our contracted operations have derivative fuel supply contracts that are recorded at fair value and are subject to changes in fair value, generally driven by changing prices in the fuels used to fire the plants (primarily natural gas). Operating results at these plants may vary from period to period.

Our merchant power operations include plants that operate during peak periods without dedicated power contracts. Generally, these plants operate when there is demand for their power and when the market price of power exceeds the plant's variable costs of generating power. Many of our merchant plants have contractual obligations, such as transportation capacity contracts, that represent fixed costs for the plant. Our ability to recover these fixed operating costs depends largely on electricity demand and the volume of power generated as well as the margins that can be realized.

Historically, we conducted a significant portion of our domestic power operations through Chaparral, an unconsolidated joint venture. In 2003, we acquired the remaining joint venture partner's interest in Chaparral and consolidated its operations effective January 1, 2003. As a result, our 2003 operating results include the consolidated revenues, expenses and equity earnings from each of Chaparral's power plants while our 2001 and 2002 operating results only include the equity earnings and management fees we earned from Chaparral.

EBIT Analysis. Our 2003 EBIT loss in domestic power plant operations of $383 million was primarily due to $419 million of asset impairments on our domestic power plants and our Chaparral investment. The plant impairments resulted from the anticipated sale of most of our domestic power plants in 2004 as well as operational and contractual issues at several of our domestic plants. The impairment of Chaparral was the result of declines in the investment's value that were considered to be other than temporary. See Item 8, Financial Statements and Supplementary Data, Notes 2 and 3, for more information on these impairments. In 2004, we may record additional impairments on our power plants as a result of ongoing negotiations related to sales of our domestic power plants and an ongoing operational and contractual issue at one of our domestic plants. See Note 28 for a further discussion of this matter. In 2003, we also recorded an $88 million loss primarily due to the write-off of receivables as a result of the transfer of our interest in the Milford power facility to the plant's lenders. See Item 8, Financial Statements and Supplementary Data, Note 28, for a further description of the Milford transfer. Also contributing to these losses was a $21 million operating loss at our Eagle Point power plant. Partially offsetting these losses was $105 million of operating income generated by the power plants from Chaparral that we consolidated in January 2003.

In December 2003, our Board of Directors approved the sale of substantially all of our domestic power plant operations, which we expect to complete in 2004. The majority of plants we sold in 2003 and 2004 or expect to sell in 2004 are contracted plants that generated EBIT (before realized gains and losses and impairments) in 2003 of $160 million. By comparison, our merchant plants that we sold or expect to sell in 2004 generated EBIT losses (also before realized gains and losses and impairments) in 2003 of $47 million. Our 2004 operating results will be impacted by the timing and nature of the plants sold.

For the year ended December 31, 2002, our domestic power plant operations generated EBIT of $80 million. This EBIT was primarily generated by the equity earnings and management fees we received from Chaparral of $124 million in 2002. As described above, Chaparral was consolidated in 2003. Also contributing to EBIT was $20 million of operating income generated by our Eagle Point plant before the restructuring of its power sales contract in March 2002 (see power restructuring discussion below). Following the restructuring, the Eagle Point plant's operating income decreased. Partially offsetting these increases was a $74 million impairment of our CE Generation power plant in 2002, which resulted from the anticipated sale of this plant in early 2003. This plant generated operating income of $22 million in 2002.

For the year ended December 31, 2001, our domestic power plant operations generated EBIT of $317 million. This EBIT was primarily generated by the equity earnings and management fees we received from Chaparral of $222 million in 2001. Also contributing to our 2001 EBIT was $22 million of operating income earned by our Eagle Point power plant in 2001 before the restructuring of its power sales contract in 2002. Our CE Generation power plant, which we sold in early 2003, also generated operating income of $29 million in 2001.

Domestic Power Contract Restructuring Business

Overview. In 2001 and 2002, we and Chaparral restructured several above-market, long-term power sales contracts with regulated utilities that were originally tied to older power plants built under PURPA. 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. For a further discussion of our power restructuring activities, see Item 8, Financial Statements and Supplementary Data, Note 15.

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. In 2003, our power restructuring business related solely to the management of our existing restructured power contracts. In 2001 and 2002, our results included the impact of power contract restructuring transactions we completed in those years, in addition to the results of managing these contracts. On an ongoing basis, the results of our power restructuring business will consist of the physical sales and purchases of electricity and changes in fair value of the derivative contracts. Changes in the discount rate used to calculate the fair value of our power restructuring derivatives, which are based in part on the credit ratings of our counterparties, can significantly impact our earnings. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk for a further discussion of this discount rate risk.

Our domestic restructured power contracts currently face a number of risks that may impact our operating results in the future. We have been actively divesting the entities that hold our domestic restructured power contracts. These entities hold power supply and power purchase agreements and have debt. The power agreements are derivatives carried at fair value while the debt is recorded based on its original issuance cost. The proceeds we received in past sale transactions and may receive in future transactions generally differs from the net assets of these entities, resulting in losses. Reasons for the differences can include the use of different assumptions by the buyer in determining the fair value of these instruments. We experienced this when we sold Utility Contract Funding (UCF) at a loss of approximately $100 million in 2004 and Mohawk River Funding I and IV at a loss of approximately $15 million in 2003, and based on a pending sale of Cedar Brakes I and II that has been approved by our Board of Directors, we could incur significant additional losses in the future.

We own restructured power contracts with a fair value of $1.5 billion that are with a single counterparty, Public Service Electric and Gas (PSEG). PSEG is currently rated "investment grade" by Moody's Investor's Services and Standard & Poor's. Changes in the creditworthiness of PSEG could materially impact the fair value of these contracts and our results of operations. This risk was reduced in June 2004 when we sold UCF to Bear Stearns. We also have a restructured power contract held by Mohawk River Funding III with U.S. Gen New England. U.S. Gen filed for bankruptcy in 2003, and increases or decreases in the amount recoverable from our bankruptcy claims may significantly impact our future operating results.

EBIT Analysis. For the year ended December 31, 2003, our domestic power contract restructuring business generated EBIT of $150 million. The restructured power contracts we acquired from Chaparral in 2003 increased in fair value by $75 million and our UCF and other restructured power contracts increased in fair value by $65 million. These increases resulted primarily from the accretion of the discounted value of these contracts. Partially offsetting this EBIT was $15 million of losses and impairments related to the sale of two of our power contract restructuring entities, Mohawk River Funding I and IV.

For the year ended December 31, 2002, our domestic power contract restructuring business generated EBIT of $341 million. In 2002 we restructured the power sales contracts at our Eagle Point (also known as UCF) and Mount Carmel power plants, which resulted in net gains of $501 million, net of minority interest. Partially offsetting these gains was a $90 million contract termination fee we paid in 2002 to terminate a steam contract between our Eagle Point power plant and the Eagle Point refinery (which is included in discontinued operations). Also offsetting these gains was a $80 million loss on a power supply agreement that we entered into with our energy marketing and trading division in 2002 associated with the Eagle Point power contract restructuring transaction. The $90 million and $80 million losses were eliminated from El Paso's consolidated results.

For the year ended December 31, 2001, our domestic power contract restructuring business generated EBIT of $31 million. In 2001 we restructured the power sales contract at our CDECCA power plant (also known as Mohawk River Funding IV), which resulted in a net gain of $31 million.

International Power Plant Operations

Overview. Our international operations primarily include contracted plants and pipelines located in South America, Central America, Asia, and Europe. From November 2001 to April 2003, we conducted a majority of our power plant operations in Brazil through Gemstone, an unconsolidated joint venture. In the second quarter of 2003, we acquired our joint venture partner's interest in Gemstone and began consolidating Gemstone's debt and its investments in the Macae, Porto Velho and Araucaria power plants. As a result, our consolidated operating results beginning in April 2003 include the revenues, expenses and equity earnings from Gemstone's assets. Our 2001 and 2002 operating results only include the equity earnings we earned from Gemstone. Due to deteriorating economic conditions in several South American, Central American and Asian countries, we have recorded impairments on our international power plants in 2001 and 2002. For a further discussion of these impairments, see Item 8, Financial Statements and Supplementary Data, Note 28.

As part of our Long-Range Plan, we announced our intent to dispose of a majority of our international power operations over the next several years, with the exception of our Brazilian power operations. The future operating results of our global power division will be impacted by the timing of these sales.

EBIT Analysis-Brazil. For the year ended December 31, 2003, our Brazilian power operations generated EBIT of $177 million. This EBIT was primarily generated from operating income of $156 million at our Macae power plant, which operated at its full operational capacity throughout 2003. Our Macae power plant's power sales contract expires in 2007, at which time the plant will convert into a merchant plant that can enter into new bilateral power contracts. Also contributing to EBIT was $28 million of earnings from our interest in the Porto Velho power plant, which reached full commercial operations in the third quarter of 2003.

For the year ended December 31, 2002, our Brazilian power operations generated EBIT of $78 million. This EBIT was primarily generated from our equity earnings of $109 million from Gemstone, which was created in November 2001. As described above, we consolidated Gemstone and its interests in the Macae and Porto Velho power plants in 2003. The operations of these two power plants were the primary contributors to Gemstone's equity earnings. Partially offsetting these earnings was a $19 million fee we paid related to the cancellation of a turbine purchase order.

For the year ended December 31, 2001, our Brazilian power operations generated EBIT of $114 million. This EBIT was primarily generated from $75 million of fees that we earned for engineering, construction management and other services for the Macae power project before Gemstone acquired Macae. Also contributing to this EBIT was $23 million of operating income at our Rio Negro power plant.

In 2002 and 2003, Rio Negro's power purchaser disputed and did not pay some of its billings, which significantly decreased the power plant's operating income in those years. The power purchase agreements for the Manaus and Rio Negro Plants expire in 2005 and 2006. Based on the anticipated results of negotiations for the renewal of these contracts we recorded a $135 million impairment charge in the first quarter of 2004. See Item 8, Financial Statements and Supplementary Data, Note 22 for a description of these matters.

EBIT Analysis-Other International. For the year ended December 31, 2003, our other international power operations generated EBIT of $119 million. This EBIT was primarily generated from operating income of $49 million at our 15 Asian power plants. Also contributing to this EBIT was a $28 million gain on the sale of two of our Argentinean power plants. Our remaining EBIT was primarily generated by our Central American and European power plants.

For the year ended December 31, 2002, the EBIT loss from our other international power plant operations was $246 million. This loss was primarily due to the $342 million impairment of our Argentinean power plants and the $48 million impairment of our Chinese and Indian power plants due to deteriorating economic conditions in those countries. Partially offsetting these losses was a $77 million net gain we recorded on the restructuring and termination of a power contract at our Nejapa power plant in El Salvador. Also offsetting these losses was operating income of $46 million at our Asian power plants.

For the year ended December 31, 2001, our other international power operations generated EBIT of $9 million. This EBIT was primarily generated from operating income of $52 million at our Asian power plants and $21 million of operating income earned by our Nejapa power plant before the restructuring of its power sales contract. Also contributing to this EBIT was operating income of $12 million at our Samalayuca power plant in Mexico, which we sold in 2002. Partially offsetting this income was $74 million impairment of our East Asia and Fife power plants in 2001 due to deteriorating economic conditions in the countries where those power plants are located.

Other Global Power Operations

For the year ended December 31, 2003, the EBIT loss from our other global power operations was $70 million. This loss was primarily due to a $22 million settlement charge in 2003 associated with the cancellation of purchase obligations on two power turbines and an $11 million impairment of our capitalized turbine costs. The remaining EBIT loss was primarily due to general and administrative costs in our global power division, which have remained relatively consistent in 2002 and 2003. We expect these costs to decrease in 2004 as we sell our domestic power assets, partially offset by increased severance due to the asset sales.

For the year ended December 31, 2002, the EBIT loss from our other global power operations was $259 million. This loss was primarily due to a $162 million impairment of our capitalized domestic and international turbine costs and a $44 million goodwill impairment charge on our financial services business that we recorded in 2002 due to our reduced capital expenditure plans related to future power and financial services investments. The remaining EBIT loss was primarily due to general and administrative costs in our global power division.

For the year ended December 31, 2001, the EBIT loss from our other global power operations was $10 million. This loss was primarily due to general and administrative costs in our global power division.

Energy Marketing and Trading Division

Our Energy Marketing and Trading division's operations primarily center around the management of its trading portfolio and marketing of our natural gas and oil production. As mentioned previously, the information related to this division has been restated to correct the manner in which we accounted for many of the hedges of our anticipated natural gas production and certain other derivative transactions. As a result of the deterioration of the energy trading environment in late 2001 and 2002, we announced 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.

As a part of our Long-Range Plan, we announced that our historical energy trading operations would become a marketing and trading business focused principally on the physical marketing of natural gas and oil produced in our Production segment. At this time, we do not anticipate the early liquidation of all 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 segment and our global power division. Changes to our liquidation strategy may impact the cash flows and the financial results of this division.

Our trading portfolio contains derivative and non-derivative contracts. Our derivative contracts primarily impact our gross margin through changes in their fair value each period. The fair value of our derivative contracts fluctuates monthly because of a variety of market factors that impact commodity prices, which are difficult to estimate or predict. For a discussion on our methodology of determining the fair value of our derivative contracts, see Item 8, Financial Statements and Supplementary Data, Note 15. Our non-derivative contracts primarily relate to obligations under our long-term pipeline transportation and natural gas storage contracts. In 2003, demand charges on these contracts were $177 million. The transportation contracts impact our gross margin as delivery or service under the contract occurs, and income or loss is based on the difference between the demand charge and the locational price difference for the delivery points under the contract.

During 2003, our trading business operated in a challenging environment with reduced liquidity, lower credit standing of participants and a general decline in the number of trading counterparties. Additionally, in the fourth quarter of 2002, we implemented new accounting rules (Emerging Issues Task Force (EITF) Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities*) that significantly impacted the carrying value of our portfolio. Many contracts which were accounted for as derivative contracts in 2002 are now accounted for as non-derivative contracts. All of these factors reduce the comparability of our operating results between periods.

Below are the operating results and analysis of these results for our Energy Marketing and Trading division for each of the three years ended December 31:

Energy Marketing and Trading Division Results	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Gross margin	$(636)	$(1,316)	$1,832
Operating expenses	(183)	(677)	(137)
Operating income (loss)	(819)	(1,993)	1,695
Other income	10	16	26
EBIT	$(809)	$(1,977)	$1,721

Year Ended December 31, 2003

For the year ended December 31, 2003, we had an EBIT loss of $809 million. During 2003, we experienced a $424 million decrease in the fair value of our derivatives, primarily our natural gas contracts. We sell natural gas at a fixed price in many of these contracts. With the significant increase in natural gas prices during 2003, the difference between the fixed prices in these contracts and the market prices continued to increase and, as a result, the fair value of these derivatives decreased resulting in losses. Also contributing to this loss was $47 million of gross margin losses from the early termination of our derivative and non-derivative contracts that resulted from the ongoing liquidation of our trading portfolio in 2003. We also recorded a $32 million net reduction in the carrying value of bankruptcy claims on three of our trading counterparties, NRG Power Marketing, Mirant Corporation and Enron Corporation, which is included in gross margin. Our non-derivative contracts had settlement losses of $165 million in 2003, which were primarily due to demand charges we could not recover on our transportation contracts. In 2003, price differentials at the contractual delivery points were not wide enough to recover our demand charges under these contracts. Partially offsetting these losses was a $30 million gross margin gain on the sale of several LNG contracts and a $78 million increase in the fair value of our Midwest derivative tolling agreement. This tolling contract is sensitive to changes in forecasted power prices relative to natural gas prices in the Midwest. These forecasted power prices increased significantly relative to natural gas prices at the end of 2003, which increased the fair value of this contract by $52 million in the fourth quarter of 2003. We expect the fair value of this contract will be volatile over its entire contract term, which extends through 2019. In 2003, we also recorded $26 million of accretion expense, net of adjustments, on our portion of the Western Energy Settlement, and $28 million of bad debt expense associated with a fuel supply agreement we have with the Berkshire power plant in operating expenses. See Item 8, Financial Statements and Supplementary Data, Note 28 for a further discussion of Berkshire. Our remaining 2003 operating expenses of $129 million included general and administrative expenses, which decreased from 2002 to 2003 due to decreases in employee headcount in 2003. We anticipate that these costs will continue to decline as a result of previous and future employee headcount and other cost reductions in this division through 2004.

Year Ended December 31, 2002

For the year ended December 31, 2002, we had an EBIT loss of approximately $2 billion. This loss was primarily the result of a $1.2 billion decrease in the fair value of our derivative positions, which are included in gross margin. In 2002, we experienced 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 in 2002. Additionally, in the fourth quarter of 2002, many of the participants in the trading industry, including us, publicly announced their intention to discontinue or significantly reduce trading operations, which we believe, along with other factors caused a deterioration of the market valuations of trading and marketing assets. The decrease in the fair value of our derivatives was primarily related to the reduced option value, with the remainder of the decrease resulting from volatility of forward prices and reductions in creditworthiness of our counterparties. Additionally, because of these issues, we significantly reduced our origination activities in 2002 compared to 2001. Also contributing to the loss was a decrease in gross margin of $25 million that resulted from the early termination of several of our non-derivative transportation contracts that resulted from the ongoing liquidation of our trading portfolio in 2002. Partially offsetting these losses was a $59 million gain we recorded in the second quarter of 2002 on a long-term LNG supply contract with Snøhvit, which was subsequently sold in the fourth quarter of 2002. Also contributing to this loss was a $487 million charge related to the Western Energy Settlement, which is included in operating expenses. Our remaining 2002 operating expenses of $190 million include general and administrative expenses, which increased from 2001 to 2002 due to an expansion of our trading operations in 2002 before the decision to liquidate our trading portfolio in late 2002.

Year Ended December 31, 2001

For the year ended December 31, 2001, we had EBIT of approximately $1.7 billion. This EBIT was primarily due to a $1.6 billion increase in the fair value of our derivatives in 2001 from increases in trading volumes and price volatility of our trading portfolio, net of reserves established for the bankruptcy of Enron in 2001. In addition, we sell natural gas at a fixed price in many of our natural gas derivative contracts. With the significant decrease in natural gas prices during 2001, the difference between the fixed prices in these contracts and the market prices continued to improve and, as a result, the fair value of these derivatives increased resulting in mark-to-market gains. We also originated several power, natural gas and transportation contracts in 2001 that generated gross margin of $211 million. Partially offsetting this EBIT was 2001 operating expenses of $137 million. These operating expenses include general and administrative expenses, which steadily increased before the decision to liquidate our trading portfolio in late 2002.

LNG Division

In 2001 and 2002, our LNG division included the development of LNG terminals and our Energy Bridge technology and holding the long-term charter arrangements on ships that employed this technology. In 2003, we announced our intent to exit this business because of the significant capital and credit requirements associated with this business. We have either sold or are in the process of selling all of our LNG operations.

Results of our LNG division were as follows for each of the three years ended December 31:

LNG Division Results	2003	2002	2001
		(In millions)	
Gross margin	$ —	$ (1)	$ 2
Operating expenses	(177)	(34)	(27)
Operating loss	(177)	(35)	(25)
Other income (expense)	(8)	—	—
EBIT	$(185)	$(35)	$(25)

Year Ended December 31, 2003

We reported an EBIT loss of $185 million for the year ended December 31, 2003. This loss primarily resulted from a $119 million loss on the sale of the assets and intellectual property rights related to our Energy Bridge technology, as well as the termination our obligations under the long-term ship charters related to this technology. Also contributing to this loss were $33 million of other asset impairments of our capitalized terminal development and testing facility costs. Our realized and unrealized losses were included as part of our operating expenses.

Years Ended December 31, 2002 and 2001

We reported an EBIT loss of $35 million and $25 million for the years ended December 31, 2002 and 2001 related primarily to our operating expenses. These operating expenses related to environmental and engineering costs we incurred related to the development of our terminals and testing the regasification process used by our Energy Bridge technology.

Corporate and Other Expenses, Net

Our Corporate and Other operations include general and administrative functions as well as the operations of our telecommunications and other miscellaneous businesses. During 2001, there was a significant downturn in the telecommunications market. As a result, we refocused our telecommunications strategy and reduced our capital investment in this business. We currently provide wholesale metropolitan transport services in Texas and collocation services through a facility in Chicago. In April 2004, we sold 28 percent of our interest in our Texas metro transport business to Genesis Park, L.P., a third party investment partnership, and changed the name to Alpheus Communications.

In December 2002, we decided to exit our long-haul and metro dark fiber business because of the minimal contribution and high cost of maintaining this business. Under these circumstances, we reduced the carrying value of our inventory to $5 million by recording an impairment of $153 million. The market value was determined by an independent appraiser who evaluated the dark fiber value based on market conditions existing in the fourth quarter of 2002 and recent liquidation values for dark fiber. In addition, because of the continuing decline of economic conditions in the telecommunications industry, we periodically evaluated the fair value of our Texas-based assets. During 2003, we recognized a $163 million goodwill impairment based on our evaluations of the amounts we would recover from this business.

Our collocation and cross-connect services are available through our Lakeside Technology Center, a Chicago-based telecommunications facility. The building design, which is beneficial for the needs of a telecommunications provider, has limited alternative uses. Due to the ongoing decline in the industry and the loss of a significant tenant in the building in 2002, we recorded a contingent loss totaling $113 million, of which $11 million was recognized immediately. The remaining $102 million was being recorded as a quarterly charge until the end of the lease in 2006. In 2003, upon the consolidation of the lessor, to whom we provided a full guarantee of repayment, we recognized an additional impairment of $127 million.

In May 2004, we announced we would consolidate our Houston-based operations into one location. We anticipate the consolidation will be substantially complete by the end of 2004. As a result, we have established or will establish an accrual to record a liability for our obligations under the terms of the leases in the period that the space is vacated and available for subleasing. We currently lease approximately 912,000 square feet of office space in the buildings we are vacating under various leases with lease terms expiring in 2004 through 2014. We estimate the total accrual for the relocation will be approximately $80 million to $100 million. Expenses related to the relocation will be expensed in the period that they are incurred.

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

Corporate and other net expenses for the year ended December 31, 2003, were $368 million higher than in 2002. During 2003, we recorded impairment charges of $396 million, including an impairment of goodwill of $163 million in our telecommunications business and the losses recorded on our Lakeside Technology Center, both of which are discussed above. In 2002, we recorded $153 million of valuation adjustments of our dark fiber inventory and a $15 million impairment of our right-of-way assets in our telecommunications business. In 2003, we also incurred $42 million of employee severance costs and a $37 million loss compared with a $21 million gain in 2002 on early debt extinguishments. These actions were part of our continuing efforts to reduce debt and lower our costs. We expect to incur additional employee severance costs in 2004 as these cost reduction efforts continue. In 2002, we recorded $51 million of restructuring related costs. See Item 8, Financial Statements and Supplementary Data, Note 5, for a further discussion of these charges. Finally, we recorded $112 million of net foreign currency losses in 2003 versus $90 million of net losses in 2002, primarily related to our Euro-denominated debt.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Corporate and other net expenses for the year ended December 31, 2002, were $1.1 billion lower than in 2001. In 2001, we recorded $1.2 billion in merger-related and asset impairment charges related to our merger with Coastal. We also recognized additional 2001 costs of $144 million related to increased estimates of environmental remediation costs, legal obligations and reductions in the fair value of spare parts inventories to reflect changes in usability of spare parts inventories based on an ongoing evaluation of our operating standards and plans following the Coastal merger. In 2002, we recorded a $168 million valuation adjustment of our dark fiber inventory and right-of-way assets as discussed above, $90 million of net foreign currency losses and various incremental costs related to our 2002 restructuring activities.

Interest and Debt Expense

Over the past three years, our interest and debt expense increased. During this period, we issued debt to finance the growth of our business segments and consolidated several "off-balance sheet" financing obligations in order to simplify our balance sheet. During this period, our overall debt balances increased from approximately $16 billion in 2001 to $22 billion by December 31, 2003. During this growth period, we have raised funds in both domestic and international capital markets, the majority of which was fixed rate debt. In the future, our ability to access the capital markets and issue debt securities will be a function of market conditions and our credit ratings at that time. Based on a number of rating actions since the latter part of 2002, we anticipate that we will incur higher interest rates on any future debt issuances. Furthermore, since some of our debt offerings have been in foreign markets, currency fluctuations can impact the cost of that debt. In December 2003, we announced under our Long-Term Plan that we would reduce our long-term debt. As we continue to repay our debt obligations, our interest expense will decline in 2004 and beyond. For a further discussion of changes in our debt instruments, see Item 8, Financial Statements and Supplementary Data, Note 20. Below is an analysis of our interest and debt expense for each of the three years ended December 31 (in millions):

	2003	2002	2001
Long-term debt, including current maturities	$1,628	$1,153	$ 949
Revolving credit facilities	121	16	28
Commercial paper	—	26	70
Other interest	72	130	145
Capitalized interest	(34)	(32)	(63)
Total interest and debt expense	$1,787	$1,293	$1,129

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

Interest expense on long-term debt for the year ended December 31, 2003, was $475 million higher than in 2002. The increase was due to higher average debt balances in 2003 compared with 2002. We consolidated Chaparral, Gemstone and Lakeside in 2003, which increased our debt by $2.1 billion as of December 31, 2003 and increased our interest expense by $236 million in 2003. In addition, our debt and other financing obligations increased by another $1.0 billion in 2003 associated with other debt issuances and consolidations. We also consolidated approximately $1.5 billion of debt in early 2003 that we paid off in late 2003. These two changes in debt increased our interest expense by approximately $219 million in 2003. Also contributing to the increase was $20 million due to the reclassification of $625 million of preferred securities as a result of the adoption of SFAS No. 150. Additionally, our interest expense increased in 2003 due to debt issuances and debt consolidations in 2003 at higher average interest rates than debt retired during the period.

Interest expense on revolving credit facilities for the year ended December 31, 2003, was $105 million higher than in 2002 due to the higher borrowings under these facilities in 2003. Our average revolving credit balances, which were based on daily ending balances, were approximately $1.5 billion, with an average interest rate of 3.97% during 2003.

Interest expense on commercial paper for the year ended December 31, 2003, was $26 million lower than in 2002 due to the discontinuance of commercial paper activities in the fourth quarter of 2002.

Other interest for the year ended December 31, 2003, was $58 million lower than in 2002. The decrease was primarily due to a $23 million reduction in interest expense from the retirement of other financing obligations, a $16 million reduction in affiliated interest expense on notes we had with Chaparral and Gemstone which were eliminated as a result of the consolidation of these investments in the second quarter of

2003, and a $19 million decrease due to the discontinuance of factoring activities in 2003. These decreases were partially offset by a $7 million increase as a result of the write-off of unamortized financing costs due to the retirement of the Trinity River financing arrangement in 2003.

Capitalized interest for the year ended December 31, 2003, was $2 million higher than in 2002 primarily due to higher average interest rates in 2003 than in 2002.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Interest expense on long-term debt for the year ended December 31, 2002, was $204 million higher than in 2001. The increase was due to a higher average debt balance. During 2002, we issued long-term debt of approximately $4.4 billion that had an average interest rate of 7.9%. These issuances increased interest on long-term debt by approximately $233 million. During the same year, we retired approximately $1.5 billion of long-term debt that had an average interest rate of 5.19%, resulting in a decrease to interest expense from these retirements of approximately $35 million. The remaining increase was primarily due to various debt issuances during 2001 that were outstanding for the entire year in 2002.

Interest expense on revolving credit facilities for the year December 31, 2002, was $12 million lower than in 2001 due to the lower borrowings under these facilities in 2002. Our average revolving credit balances, which were based on daily ending balances, were approximately $144 million, with an average interest rate of 3.36% during 2002.

Interest expense on commercial paper for the year ended December 31, 2002, was $44 million lower than in 2001 primarily due to lower average short-term interest rates on commercial paper activities in 2002.

Other interest for the year ended December 31, 2002, was $15 million lower than in 2001. The decrease was primarily due to an $8 million decrease in interest resulting from retirement of our other financing obligations, an $8 million decrease in interest related to a decline of receivable factoring, and an $8 million decrease in interest due to termination of a marketing sales contract during 2002. These decreases were partially offset by a $9 million increase in interest from the debt securities issued to Gemstone in November 2001.

Capitalized interest for the year ended December 31, 2002, was $31 million lower than in 2001 primarily due to the lower interest rates in 2002 than in 2001.

Distributions on Preferred Interests of Consolidated Subsidiaries

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

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2003, were $107 million lower than in 2002 due to the redemptions of the preferred stock on two of our subsidiaries, Trinity River and Coastal Securities, the consolidation of Gemstone which had a preferred interest of $300 million in one of our subsidiaries, the refinancing and redemption of our Clydesdale financing arrangement and the reclassification of our Capital Trust I and Coastal Finance I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150. As a result of this reclassification, we began recording the preferred returns on these securities as interest expense rather than as distributions of preferred interests.

As a result of our actions in 2003, our remaining preferred interests outstanding as of December 31, 2003 only consist of $300 million of preferred stock of El Paso Tennessee Pipeline Co. and a number of smaller interests in other consolidated subsidiaries.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2002, were $58 million lower than in 2001 primarily due to the redemptions of the preferred interests related to El Paso Oil & Gas Resources, El Paso Oil & Gas Associates, Coastal Limited Ventures, Capital Trust IV and the partial redemption of our Clydesdale financing arrangement. The decrease was also due to lower interest rates in 2002. Most of the preferred returns were based on variable short-term rates, which were lower on average in 2002 than in 2001. Partially offsetting these decreases were higher returns on preferred interests issued as part of our Gemstone investment completed in November 2001.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Item 8, Financial Statements and Supplementary Data, Note 21.

Income Taxes

Income tax benefits for the years ended December 31, 2003, 2002 and 2001 were $584 million, $649 million and $70 million resulting in effective tax rates of 49 percent, 33 percent and 15 percent. Of the 2003 amount, $139 million related to tax benefits recorded on abandonments and sales of certain of our foreign investments. The effective tax rate for 2003 absent these benefits would have been 37 percent. Included in the 2001 tax benefit was a tax charge of $115 million related to non-deductible merger charges and changes in our estimate of additional tax liabilities. Taxes on the majority of these estimated additional liabilities were paid in 2001. The effective tax rate for 2001 absent these charges would have been 40 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent in all years were primarily a result of the following factors:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends;
- non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;
- foreign income taxed at different rates;
- abandonments and sales of foreign investments;
- valuation allowances;
- deferred credit on loss carryovers;
- non-deductible dividends on the preferred stock of a subsidiary;
- non-conventional fuel tax credits;
- goodwill impairment; and
- depreciation, depletion and amortization.

For a reconciliation of the statutory rate to our effective tax rate, as well as matters that could impact our future tax expense, see Item 8, Financial Statements and Supplementary Data, Note 11.

Included in our deferred tax assets (excluding valuation allowances) as of December 31, 2003 was $400 million related to the Western Energy Settlement. Proposed tax legislation has been introduced in the U.S. Senate which would disallow deductions for certain settlements made to or on behalf of governmental entities. If enacted, this tax legislation could impact the deductibility of the expenses related to the Western Energy Settlement and could result in a write-off of some or all of the associated deferred tax assets. In such event, our tax expense would increase. For a discussion of valuation allowances based on our ability to utilize state tax benefits from deduction of the charge we took related to the Western Energy Settlement, see Item 8, Financial Statements and Supplementary Data, Note 11.

Discontinued Operations

In 2002 and 2003, we made the decision to eliminate our involvement in several businesses and to sell the related assets and liabilities, and, as a result, we reported the following operations as discontinued operations as of December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002, and 2001.

Petroleum Markets Operations

During 2003, our Board of Directors authorized the sale of substantially all of our petroleum markets operations. Based on our intent to dispose of these operations, we adjusted these assets to their estimated fair value and recognized pre-tax charges during 2003 totaling approximately $1.5 billion, which included $1.1 billion related to our Aruba refinery and $264 million related to the impairment of our Eagle Point refinery. In 2003, we completed the sales of $664 million of these assets and completed an additional $905 million in early 2004. We completed the sale of substantially all of our remaining petroleum markets assets in 2004.

Coal Mining Operations

In late 2002 and the first quarter of 2003, we sold our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our Board of Directors, we recorded impairment charges of $185 million in our loss from discontinued operations during 2002. We have now fully exited our coal operations.

For each of the three years ended December 31, the after-tax income (loss) related to our discontinued operations was as follows (in millions):

	2003	2002	2001
Petroleum markets	$(1,304)	$(241)	$(80)
Coal mining	1	(124)	(5)
Total discontinued operations	$(1,303)	$(365)	$(85)

For the year ended December 31, 2003, we reported a loss from our discontinued operations of $1.3 billion. This was primarily due to impairments of long-lived assets of $1.5 billion, including $1.1 billion related to our Aruba refinery and $264 million related to our Eagle Point refinery. In addition, our Aruba refinery continued to generate operating losses of approximately $82 million. These losses resulted from lower throughput at Aruba due primarily to operational difficulties following a fire at the facility in April 2001 and scheduled turnaround maintenance activities. Our losses were partially offset by operating income at our Eagle Point refinery of approximately $42 million. This income resulted from higher margins at Eagle Point due to a widening difference between the price of the crude oil inputs used by the refinery and the prices we sold the refined products produced. This loss was also partially offset by $90 million of gains recorded on the sale of our Florida terminalling and transportation assets, asphalt facilities and chemical facilities in 2003 and $65 million of business interruption and property damage insurance recoveries related to the Aruba facility fire in 2001.

For the year ended December 31, 2002, we reported a loss from discontinued operations of $365 million. This was primarily due to operating losses of approximately $129 million at our Aruba refinery, resulting from operational difficulties following the fire at the facility. Also contributing to this loss was a $185 million impairment of our coal mining operations and a $91 million impairment of our MTBE chemical processing plant. Our losses were partially offset by operating income at our Eagle Point refinery of approximately $97 million, resulting from higher throughput at Eagle Point during 2002 due to a widening difference between the price of the crude oil input used by the refinery and the prices at which we sold the products produced. This loss was also partially offset by $46 million of insurance recoveries in 2002 related to the assets destroyed in the Aruba fire.

For the year ended December 31, 2001, we reported a loss from discontinued operations of $85 million. This loss included $262 million of merger-related costs, asset impairments and other charges associated with our merger with Coastal in 2001. See Item 8, Financial Statements and Supplementary Data, Notes 5 and 7 for a discussion of these merger-related costs and asset impairments. Also contributing to the loss was an operating loss of $87 million at the Eagle Point refinery as a result of lower margins and throughput. Partially offsetting these losses was $97 million of insurance recoveries related to the fire at the Aruba refinery, operating income of $126 million from our refined product and crude oil marketing activities and $23 million of other income which includes equity earnings and income from the lease of our Corpus Christi refinery to Valero.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 22, 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. 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. 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.

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. As of December 31, 2003, of our total proved reserves, 34 percent were undeveloped and 12 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. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields increases the likelihood of significant changes in these estimates. If all other factors are held constant, an increase in estimated proved reserves decreases our unit of production depletion rate. Higher reserves can also reduce the likelihood of ceiling test impairments. For further discussions of our reserves as well as the restatement of our historical financial statements as a result of downward revisions to our reserve estimates, see Part I, Item 1, Business, under Production segment and Item 8, Financial Statements and Supplementary Data, Notes 1 and 30.

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 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 equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. 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. As a result of determining that we had not properly applied the accounting rules for hedges of our natural gas production, we recorded additional ceiling test charges in 2001. See a further discussion of the restatement for the manner in which we historically accounted for natural gas hedges in Item 8, Financial Statements and Supplementary Data, Note 1.

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. We attempt to realize more determinable cash flows through the use of hedges, but a decline in commodity prices can impact the results of our ceiling test and may result in writedowns.

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 $880 million, $444 million and $75 million during the years ended December 31, 2003, 2002 and 2001. We recorded impairments of our discontinued operations of $1.5 billion, $290 million and $103 million during the years ended December 31, 2003, 2002 and 2001. Future changes in the economic and business environment can impact our original and ongoing 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, 2003, we had accrued approximately $412 million for environmental matters. Our reserve estimates range from approximately $412 million to approximately $632 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 ($94 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($318 million to $538 million) and the lower end of the range has been accrued.

Accounting for Pension and Other Postretirement Benefits. Our accruals related to our pension and other postretirement benefits are based on actuarial calculations. In performing these calculations, our actuaries must use 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 cost of health care when benefits are provided under our plans and other factors.

Actual results may differ from the assumptions included in these actuarial calculations, and as a result our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future, with either a negative or positive effect on the costs we recognize and the accruals we make. 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, 2003 (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	$ (2)	$(193)	$—	$(45)
Expected return on plan assets	(26)	—	(1)	—
Rate of compensation increase	1	1	—	—
Health care cost trends	—	—	1	21
One percent decrease in:				
Discount rates	$ 17	$ 232	$—	$ 48
Expected return on plan assets[1]	26	—	1	—
Rate of compensation increase	(1)	(1)	—	—
Health care cost trends	—	—	(1)	(19)

(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, 2003.

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. Due to losses in our pension plan assets during 2002, the fair value of plan assets used to determine the 2003 net benefit expense (income) was less than the market-related value of plan assets. 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 income would have been $108 million lower for the year ended December 31, 2003.

We have not recorded an additional pension liability for our primary pension plan because the fair value of plan assets exceeded the accumulated benefit obligation in that plan by approximately $202 million and $362 million as of September 30, 2003 and December 31, 2003. If the accumulated benefit obligation exceeded plan assets under this primary pension plan as of September 30, 2003, 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 the primary pension 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 Item 8, Financial Statements and Supplementary Data, Note 2 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 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 $22 billion as of December 31, 2003 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 (with a negative outlook and under review for a possible downgrade) and CCC+ by Standard & Poor's (with a negative outlook). 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 expected debt maturities as of December 31, 2003 for 2004, 2005 and 2006 are $1,409 million, $1,585 million and $1,769 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 Item 8, Financial Statements and Supplementary Data, Note 20, 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 or by competing asset sale programs by our competitors, (2) our ability to recover 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, trading and LNG 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 recorded 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. 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 revolving credit facility, and could accelerate our long-term debt and other financing obligations and that of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

As discussed in Item 8, Financial Statements and Supplementary Data, Note 1, we have restated our historical financial statements to reflect a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges primarily associated with our anticipated natural gas production.

We believe that the material restatements of our financial statements as discussed in Item 8, Financial Statements and Supplementary Data, Note 1 would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions; specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our $3 billion revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension with various lenders until November 30, 2004 to file our first and second quarter 2004 Forms 10-Q, which we expect to meet. If we are unable to file these Forms 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our $3 billion revolving credit facility and various other transactions could be accelerated. As part of obtaining these waivers, we also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default and limitations on our ability as well as that of our subsidiaries, to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our $3 billion revolving credit facility could constitute an event of default under some of our other debt agreements. In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived the financial filing requirements through December 31, 2004. The filing of our first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the event of non-compliance resulting from our failure to file financial statements on these subsidiaries. In addition, neither we nor any of our subsidiaries have received notice of the default caused by our failure to file our financial statements or the financial statements of our subsidiaries also impacted by the restatement. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

Furthermore, material restatements of our financial statements for the period ended December 31, 2001 could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004. Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

Our ability to access capital markets under our existing shelf registration statement may be limited as a result of the restatement of our historical financial results.

In March 2004, we announced that a downward revision of our natural gas and oil reserves would result in a restatement of our historical financial statements. In August 2004, we announced that we would be required to further restate our historical financial statements for 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 annual report on this Form 10-K was not filed in a timely manner which, for a period of 12 months from the date of this filing, will restrict our ability to access approximately $1 billion of capacity under our shelf registration statement without filing additional disclosure information with the SEC, which may be subject to a full review. 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.

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 May 2004, we completed an independent investigation of the reason for or cause of the significant revisions to our natural gas and oil reserves. Following this investigation, we announced that we would reduce our proved natural gas and oil reserve estimates as of December 31, 2003 by approximately 1.8 Tcfe and, as a result, restate our historical financial statements. In August 2004, we announced that we would be required to further restate our historical financial statements for 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, and conducted an additional investigation into the reasons for this restatement. As a result of our 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.

If we are unable to certify the effectiveness of our internal controls over financial reporting, we could suffer a loss of public confidence in our internal controls, which could have a negative impact on our financial performance and the market value of our common stock.

Item 308 of Regulation S-K, which was promulgated pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, requires us, as of December 31, 2004, 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 individually opine on the effectiveness of our internal controls over financial reporting. In connection with our ongoing efforts to assess the effectiveness of the design and operation of our internal controls, we have identified several deficiencies that collectively constitute a material weakness in our internal controls. We have taken or are taking significant steps to remediate these deficiencies. For more information regarding our evaluation of our internal controls, the identified deficiencies therein and our remediation efforts related thereto, see Item 9A, Controls and Procedures. If we timely complete our assessment of our internal controls, but we do not adequately address known material weaknesses or we discover other material weaknesses, this will be disclosed in management's assessment of our internal controls in our periodic filings. If our auditor either disagrees with our assessment or otherwise concludes that our internal controls are not effective, this will be disclosed in the auditor's report on internal controls in our periodic filings. Furthermore, if we or our auditors are unable to timely complete an assessment of our internal controls or our auditors' review of our assessment efforts, we would be deficient in our reporting obligations under the Securities Exchange Act of 1934, which may restrict our access to the capital markets and would result in non-compliance with the filing obligations in a significant portion of our financing documents, which could result in an event of default under one or more of those documents. Under any of these circumstances, we could be subjected to additional regulatory scrutiny and suffer a loss of public confidence in our internal controls, which could have a negative impact on our financial performance and the market value of our common stock.

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. 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 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
- the possible introduction of future environmental laws and regulations.

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 Item 8, Financial Statements and Supplementary Data, Note 22.

Costs of other litigation matters could exceed our estimates.

We are involved in various lawsuits in which we or our subsidiaries have been sued. 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, see Part I, Item 8, Financial Statements and Supplementary Data, Note 22.

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, in part, depends 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:

- future weather conditions, including those that favor alternative energy sources such as hydroelectric power;
- price competition;
- drilling activity and supply availability of natural gas;
- expiration and/or turn back of significant contracts;
- service area competition;
- changes in regulation and action of regulatory bodies;

- credit risk of our customer base;
- 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 associated with a pipeline subsidiary; 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. For example, Southern California Gas Company, EPNG's largest customer, requested, and in September 2004 received, the approval of the California Public Utilities Commission to give notice to terminate certain of its transportation agreements with us by February 25, 2005, with the intent of negotiating to reduce its capacity holdings on that pipeline system as part of an effort to diversify its capacity holdings. For a further discussion of these matters, see Part I, Item I, Business — Regulated Businesses — Pipelines Segment, Markets and Competition.

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 and earnings.

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. 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. 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 or changes in basis differentials could adversely affect the financial results of our exploration and production business.

Our future financial condition, revenues, results of operations, cash flows, future rate of growth and the carrying value of our natural gas and oil properties 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;
- 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 83 percent of our proved reserves at December 31, 2003 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, including exploratory programs that recently have not been successful;
- 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 as evidenced by our lack of success in recent exploratory programs. New wells drilled by us may be unproductive, 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 also due to wells that are productive but do 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.

The reserve data included in this report represents estimates. 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, 2003, approximately 34 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 undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of producing reserves.

The success of our power generation activities, in part, depends 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 U.S. 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 unhedged positions or hedging procedures do not work as planned, fluctuating commodity prices could cause our sales, 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 Item 8, Financial Statements and Supplementary Data, Note 14.

Our foreign operations and investments involve special risks.

Our activities in areas outside the U.S., including a material concentration and investment exposure in our international power, pipeline and production projects of approximately $1.6 billion located in Brazil and approximately $0.3 billion in 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.

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 Merchant Energy segment; and
  - Electricity and natural gas prices change, affecting the value of our natural gas contracts, power contracts and tolling contracts held in our Merchant Energy segment.
- 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.

Each segment manages 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. Discussions of our accounting policies for derivative instruments are included in Item 8, Financial Statements and Supplementary Data, Notes 2 and 15.

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.

Merchant Energy

Our Merchant Energy 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 Merchant Energy'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 $34 million as of December 31, 2003 and 2002. Our highest, lowest and average of the month end values for Value-at-Risk during 2003 was $48 million, $23 million and $37 million. Actual losses in fair value may exceed those measured by Value-at-Risk. The amounts for 2002 have been restated to reflect a change in our accounting for hedges of our anticipated natural gas production and certain other derivatives. In August 2004, we determined that these hedges did not qualify as cash flow hedges at a consolidated reporting level and, as a result, were required to be recorded as mark-to-market contracts that are subject to the same commodity price risk as our other trading contracts. Our Value-at-Risk was restated to reflect the derivatives that no longer qualified for hedge accounting.

After the restatement, our Merchant Energy segment's primary exposure to commodity price risk relates to its natural gas positions and its derivative tolling contract in the Midwest. These positions have been sensitive to the price changes in natural gas and power that occurred in 2003. This has caused significant fluctuations in our earnings and our Value-at-Risk from period to period.

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, 2003 and 2002. This information has also been restated to reflect only derivative commodity instruments that qualify for accounting purposes as hedges of anticipated natural gas production. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
			(In millions)		
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2003	$(45)	$(60)	$(15)	$(30)	$15
December 31, 2002 (Restated)	$(33)	$(48)	$(15)	$(18)	$15

The derivatives described above do not hedge all of our commodity price risk related to our forecasted sales of our natural gas production and as a result, we are subject to commodity price risks on our remaining forecasted natural gas production. In addition, we entered into new hedges in 2004 for 5.5 TBtu of our anticipated natural gas production at an average price of $5.64 per MMBtu and 1.1 MMBbls of our anticipated crude oil production at an average price of $35.15 per Bbl.

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 overall 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, 2003 and 2002, 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, 2003								December 31, 2002	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2004	2005	2006	2007	2008	Thereafter	Total	Value	Amounts	Value
					(Dollars in millions)					
Liabilities:										
Short-term debt — fixed rate	$ 56						$ 56	$ 55	$ —	$ —
Average interest rate	9.4%									
Long-term debt and other obligations, including current portion — fixed rate	$1,347	$580	$1,335	$ 923	$ 763	$15,156	$20,104	$19,141	$15,901	$11,488
Average interest rate	8.3%	8.2%	6.9%	7.7%	7.5%	7.5%				
Long-term debt and other obligations, including current portion-variable rate	$ 47	$996	$ 423	$ 47	$ 4	$ 55	$ 1,572	$ 1,572	$ 780	$ 780
Average interest rate	9.7%	9.7%	4.4%	10.4%	15.5%	5.4%				

Derivatives from Power Contract Restructuring Activities

Derivatives associated with our power contract restructuring business in the global power division of our Merchant Energy 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. Had we reflected the actual U.S. Treasury yields as of December 31, 2003 in our valuation, the value of our third party non-trading derivatives would have been higher by approximately $125 million. 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. As of December 31, 2003, a ten percent increase or decrease in the discount rate used to value third party positions would result in an increase (decrease) in the fair value of these derivative contracts of $(56) million and $59 million. As a result of the sale of UCF in 2004, and our pending sale of Cedar Brakes I and II in 2004, our sensitivity to interest rate changes in these derivatives will decrease.

Foreign Currency Exchange Rate Risk

Debt

Our exposure to foreign currency exchange rates relate primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2003, we have Euro-denominated debt with a principal amount of €1,050 million of which €550 million matures in 2006, and €500 matures in 2009. As of December 31, 2003 and 2002 we had entered into hedge transactions to effectively convert €625 million and €275 million of debt into $645 million and $255 million. In 2004, we entered into cross currency hedge transactions that convert €100 million fixed rate debt into $121 million floating rate debt. The remaining principal at December 31, 2003 and 2002 of €425 million and €775 million was subject to foreign currency exchange risk. For a sensitivity analysis, a hypothetical ten percent increase or decrease in the Euro/USD exchange rate of 1.2595, with all other variables held constant, at December 31, 2003, would increase or decrease the carrying value of our unhedged Euro-denominated debt by approximately $54 million.

Power Contracts

Several of our international power plants in Asia, Central 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

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,		
	2003	2002 (Restated)	2001 (Restated)
Operating revenues			
Pipelines	$ 2,647	$ 2,610	$ 2,742
Production	2,229	2,003	2,486
Field Services	1,529	2,029	2,553
Merchant Energy	390	409	2,366
Corporate and eliminations	(84)	(134)	67
	6,711	6,917	10,214
Operating expenses			
Cost of products and services	1,787	2,423	2,450
Operation and maintenance	2,017	2,110	2,064
Merger-related costs	—	—	1,493
Depreciation, depletion and amortization	1,207	1,180	1,380
Ceiling test charges	76	128	2,143
Loss on long-lived assets	949	185	77
Western Energy Settlement	104	899	—
Taxes, other than income taxes	296	255	316
	6,436	7,180	9,923
Operating income (loss)	275	(263)	291
Earnings (losses) from unconsolidated affiliates	363	(226)	437
Other income	203	197	288
Other expenses	(202)	(239)	(128)
Interest and debt expense	(1,787)	(1,293)	(1,129)
Distributions on preferred interests of consolidated subsidiaries	(52)	(159)	(217)
Loss before income taxes	(1,200)	(1,983)	(458)
Income taxes	(584)	(649)	(70)
Loss from continuing operations	(616)	(1,334)	(388)
Discontinued operations, net of income taxes	(1,303)	(365)	(85)
Extraordinary items, net of income taxes	—	—	26
Cumulative effect of accounting changes, net of income taxes	(9)	(54)	—
Net loss	$(1,928)	$(1,753)	$ (447)
Basic and diluted loss per common share			
Loss from continuing operations	$ (1.03)	$ (2.38)	$ (0.77)
Discontinued operations, net of income taxes	(2.18)	(0.65)	(0.17)
Extraordinary items, net of income taxes	—	—	0.05
Cumulative effect of accounting changes, net of income taxes	(0.02)	(0.10)	—
Net loss	$ (3.23)	$ (3.13)	$ (0.89)
Basic and diluted average common shares outstanding	597	560	505

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2003	December 31, 2002 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,429	$ 1,591
Accounts and notes receivable		
Customer, net of allowance of $273 in 2003 and $176 in 2002	2,057	4,202
Affiliates	189	774
Other	246	337
Inventory	184	252
Assets from price risk management activities	706	874
Margin and other deposits held by others	203	1,003
Assets of discontinued operations	1,369	2,154
Assets held for sale	1,139	31
Restricted cash	590	124
Deferred income taxes	592	245
Other	218	193
Total current assets	8,922	11,780
Property, plant and equipment, at cost		
Pipelines	18,563	18,049
Natural gas and oil properties, at full cost	15,763	14,956
Power facilities	1,660	959
Gathering and processing systems	334	1,102
Other	998	750
	37,318	35,816
Less accumulated depreciation, depletion and amortization	18,724	17,924
Total property, plant and equipment, net	18,594	17,892
Other assets		
Investments in unconsolidated affiliates	3,551	4,891
Assets from price risk management activities	2,338	1,757
Goodwill and other intangible assets, net	1,088	1,368
Assets of discontinued operations	—	1,911
Other	2,591	2,466
	9,568	12,393
Total assets	$37,084	$42,065

See accompanying notes.

EL PASO CORPORATION

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

	December 31, 2003	December 31, 2002 (Restated)
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 1,553	$ 3,581
Affiliates	26	29
Other	476	742
Short-term financing obligations, including current maturities	1,457	2,075
Notes payable to affiliates	—	189
Liabilities from price risk management activities	734	1,017
Western Energy Settlement	633	100
Liabilities of discontinued operations	658	1,373
Liabilities related to assets held for sale	236	—
Accrued interest	391	326
Other	910	900
Total current liabilities	7,074	10,332
Debt		
Long-term financing obligations, less current maturities	20,275	16,106
Notes payable to affiliates	—	201
	20,275	16,307
Other		
Liabilities from price risk management activities	781	1,170
Deferred income taxes	1,571	2,094
Western Energy Settlement	415	799
Liabilities of discontinued operations	—	87
Other	2,047	1,984
	4,814	6,134
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	300	3,255
Minority interests of consolidated subsidiaries	147	165
	447	3,420
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 639,299,156 shares in 2003 and 605,298,466 shares in 2002	1,917	1,816
Additional paid-in capital	4,576	4,444
Retained earnings (accumulated deficit)	(1,785)	143
Accumulated other comprehensive income (loss)	11	(235)
Treasury stock (at cost); 7,097,326 shares in 2003 and 5,730,042 shares in 2002	(222)	(201)
Unamortized compensation	(23)	(95)
Total stockholders' equity	4,474	5,872
Total liabilities and stockholders' equity	$37,084	$42,065

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2003	2002 (Restated) [1]	2001 (Restated) [1]
Cash flows from operating activities			
Net loss	$(1,928)	$(1,753)	$ (447)
Less loss from discontinued operations, net of income taxes	(1,303)	(365)	(85)
Net loss before discontinued operations	(625)	(1,388)	(362)
Adjustments to reconcile net loss to net cash from operating activities			
Depreciation, depletion and amortization	1,207	1,180	1,380
Western Energy Settlement	94	899	—
Ceiling test charges	76	128	2,143
Deferred income tax expense (benefit)	(719)	(693)	1
Non-cash portion of merger-related costs and changes in estimates	—	—	1,066
Loss on long-lived assets	874	185	77
Losses (earnings) from unconsolidated affiliates, adjusted for cash distributions	(18)	533	(38)
Other non-cash income items	415	304	142
Asset and liability changes			
Accounts and notes receivable	2,548	(626)	1,274
Inventory	74	248	30
Change in non-hedging price risk management activities, net	85	1,074	(711)
Accounts payable	(2,127)	(128)	(1,044)
Broker and other margins on deposit with others	623	(257)	88
Broker and other margins on deposit with us	32	(647)	210
Other asset and liability changes			
Assets	(280)	14	(441)
Liabilities	116	(119)	114
Cash provided by continuing operations	2,375	707	3,929
Cash provided by (used in) discontinued operations	(46)	(271)	191
Net cash provided by operating activities	2,329	436	4,120
Cash flows from investing activities			
Additions to property, plant and equipment	(2,452)	(3,430)	(3,868)
Purchases of interests in equity investments	(38)	(299)	(956)
Cash paid for acquisitions, net of cash acquired	(1,078)	45	(299)
Net proceeds from the sale of assets and investments	2,529	2,826	905
Net change in restricted cash	(534)	(260)	3
Net change in notes receivable from affiliates	(43)	4	(608)
Other	—	22	12
Cash used in continuing operations	(1,616)	(1,092)	(4,811)
Cash provided by (used in) discontinued operations	427	(163)	(212)
Net cash used in investing activities	(1,189)	(1,255)	(5,023)

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

See accompanying notes.

EL PASO CORPORATION

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

	Year Ended December 31,		
	2003	2002 (Restated)[1]	2001 (Restated)[1]
Cash flows from financing activities			
Net short-term borrowings (repayments)	$ 76	$ 60	$ (786)
Net long-term borrowings (repayments)	(18)	2,008	1,163
Payments to minority interest holders and preferred interest holders	(1,277)	(861)	—
Issuances of common stock	120	1,053	915
Dividends paid	(203)	(470)	(387)
Proceeds from issuance of minority interests	—	33	281
Contributions from (distributions to) discontinued operations	381	(995)	99
Cash provided by (used in) continuing operations	(921)	828	1,285
Cash provided by (used in) discontinued operations	(381)	444	15
Net cash provided by (used in) financing activities	(1,302)	1,272	1,300
Change in cash and cash equivalents	(162)	453	397
Less increase (decrease) in cash and cash equivalents related to discontinued operations	—	10	(6)
Change in cash and cash equivalents from continuing operations	(162)	443	403
Cash and cash equivalents			
Beginning of period	1,591	1,148	745
End of period	$ 1,429	$ 1,591	$ 1,148

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

See accompanying notes.

EL PASO CORPORATION

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

	For the Years Ended December 31,					
	2003		2002 (Restated)		2001 (Restated)	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	605	$ 1,816	538	$ 1,615	514	$1,541
Equity offering	—	—	52	155	20	61
Exchange of equity security units	15	45	—	—	—	—
Conversion of Coastal options	—	—	—	—	4	13
Conversion of FELINE PRIDES℠	—	—	12	37	—	—
Western Energy equity offerings	18	53	—	—	—	—
Other, net	1	3	3	9	—	—
Balance at end of year	639	1,917	605	1,816	538	1,615
Additional paid-in capital:						
Balance at beginning of year		4,444		3,130		1,925
Compensation related issuances		8		57		188
Conversion of Coastal options		—		—		265
Tax effects of equity plans		(26)		15		31
Equity offering				846		802
Exchange of equity security units		189		—		—
Conversion of FELINE PRIDES℠		—		423		—
Western Energy equity offerings		67		—		—
Dividends ($0.16 per share)		(96)		—		—
Other		(10)		(27)		(81)
Balance at end of year		4,576		4,444		3,130
Retained earnings:						
Balance at beginning of year		143		2,387		3,269
Net loss		(1,928)		(1,753)		(447)
Dividends ($0.87 and $0.85 per share)		—		(491)		(435)
Balance at end of year		(1,785)		143		2,387
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(235)		(18)		(65)
Other comprehensive income (loss)		246		(217)		47
Balance at end of year		11		(235)		(18)
Treasury stock, at cost:						
Balance at beginning of year	(6)	(201)	(8)	(261)	(14)	(400)
Compensation-related issuances		—	3	79	1	11
Other	(1)	(21)	(1)	(19)	5	128
Balance at end of year	(7)	(222)	(6)	(201)	(8)	(261)
Unamortized compensation:						
Balance at beginning of year		(95)		(187)		(125)
Issuance of restricted stock		(1)		(36)		(144)
Amortization of restricted stock		64		73		67
Forfeitures of restricted stock		15		15		4
Other		(6)		40		11
Balance at end of year		(23)		(95)		(187)
Total stockholders' equity	632	$ 4,474	599	$ 5,872	530	$6,666

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2003	2002 (Restated)	2001 (Restated)
Net loss	$(1,928)	$(1,753)	$ (447)
Foreign currency translation adjustments	159	(20)	(30)
Minimum pension liability accrual (net of income tax of $7 in 2003 and $20 in 2002)	11	(35)	—
Net gains (losses) from cash flow hedging activities:			
Cumulative effect of transition adjustment (net of income tax of $332)	—	—	(647)
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $50 in 2003, $53 in 2002 and $210 in 2001)	101	(90)	324
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $11 in 2003, $40 in 2002 and $181 in 2001)	(25)	(73)	401
Other	—	1	(1)
Other comprehensive income (loss)	246	(217)	47
Comprehensive loss	$(1,682)	$(1,970)	$ (400)

See accompanying notes.

1. Restatement of Historical Financial Statements and Liquidity

During 2004, we identified several issues that resulted in a restatement of the amounts we had previously reported in our historical financial statements for the periods from 1999 to 2002 and for the first nine months of 2003. These restatements related to revisions to our historical estimates of proved natural gas reserves and for the manner in which we accounted for certain derivatives, primarily those related to hedges of our natural gas production. Each of these restatements is discussed below.

Restatement of Historical Financial Statements

Reserve Revisions. In February 2004, we completed the December 31, 2003 reserve estimation process for the proved natural gas and oil reserves in our Production segment. At the same time, our independent reserve engineers completed their estimates of our proved reserves. Overall, our internally prepared reserve estimates were within 5 percent of the total of the estimates of our independent reserve engineers. The proved reserve estimates as of December 31, 2003 indicated a 1.8 Tcfe or approximate 41 percent downward revision in our proved natural gas and oil reserves was needed. Given the size of this revision, the Audit Committee of our Board of Directors initiated an independent investigation to be conducted by an outside law firm to determine the factors that contributed to this significant downward revision. The scope of the investigation included (1) assessing the reasons for the downward revisions, (2) evaluating the internal controls associated with the booking of reserves, (3) suggesting any recommendations with regard to improvements in internal controls and processes and (4) recommending any remedial actions that may be required. The investigation included the completion of more than 200 interviews and the review of more than 100,000 documents. Based on the investigation results, we concluded that a material portion of the negative reserve revisions should have been reflected in periods prior to 2003 and would require a revision of the historical reserve estimates included in our supplemental natural gas and oil operations data. Quantities of proven natural gas and oil reserves are used in determining financial statement amounts, including ceiling test charges, depletion expense and gains and losses on property sales. The revision of our historical reserve estimates required the restatement of the financial statement information derived from these estimates. The investigation found that certain personnel used aggressive, and at times, unsupportable methods to book proved reserves. In some instances, certain personnel provided historical proved reserve estimates that they knew or should have known were incorrect at the time they were reported. The investigation also found that we did not, in some cases, maintain adequate documentation and records to support historically booked reserves. Based on the results of the investigation, we (a) reviewed alternatives with respect to the method or methods to be used to restate our reserve amounts in prior periods and (b) assessed and implemented remedial actions related to our management structure, internal control environment and internal control processes.

Accounting for Certain Derivatives. In August 2004, we evaluated the manner in which we historically accounted for hedges of our anticipated natural gas production and certain other hedging transactions related primarily to pipeline capacity held on pipelines and hedges of anticipated production owned by one of our pipeline subsidiaries. We entered into a significant number of hedge transactions from 1999 until 2002. In these hedge transactions, certain of our subsidiaries would enter into affiliated derivative positions with our Merchant Energy segment (usually fixed for floating swaps). Our Merchant Energy segment would then enter into an identical transaction with a third party to complete an accounting hedge for consolidated reporting purposes (the "hedge transaction"). To accomplish its own portfolio management objectives, the Merchant Energy segment would, in many cases, then enter into an offsetting transaction with that same third party. Most of the transactions with third parties to create the hedge and complete the offsetting transactions were implemented under Master ISDA swap agreements. A total of 457 hedging transactions took place during this timeframe, and 110, or approximately 24 percent involved the use of an offsetting transaction. However, approximately 79 percent of the volumes hedged during that period involved the use of an offsetting transaction. In applying the accounting treatment for these transactions in prior periods, we originally concluded that the hedge and offsetting transaction had economic substance separate and apart from each other. This conclusion was based upon several factors including (i) all of the hedges and the offsetting transactions were entered into at market prices, (ii) that our Merchant Energy segment had a valid business purpose for entering into the offsetting transaction (i.e. to permit the Company to manage the overall price risk exposure of the trading portfolio on a more efficient basis), and (iii) the view that there was credit risk associated with the separate enforcement of the hedges and offsetting transactions. In reaching the conclusion to restate our historical accounting related to these hedging transactions, we determined that we had not properly applied generally accepted accounting principles, or GAAP. First, we reviewed the factors that supported our original accounting determinations, which took into consideration the underlying business purpose for entering into the offsetting transactions, the pricing of the transactions, and the economic substance of the offsetting transactions. Upon our review of these factors, when considered in aggregate, we determined that the hedge and the offsetting transaction did not meet the requirements to be treated as separate transactions under GAAP. Principally, we determined that our business purpose for the offsetting transaction was not alone sufficient to satisfy the standards for separate accounting treatment from the hedge transaction. GAAP requires that the objective of the two transactions is not one that may be accomplished in a single transaction. Our production and other hedge objectives could have been accomplished through a single, though less efficient, transaction. In addition, we considered two additional factors in reaching this conclusion. First, we found that some of the offsetting transactions were not entered into within a range of the then current market prices. Second, we determined that there was not, as a general matter, sufficient credit risk associated with the separate enforcement of these transactions to support our original conclusion that the transactions had economic substance. Based on these conclusions, we determined that a restatement of our historical financial statements was required. Following our determination that a restatement was needed, we conducted an investigation into (a) the reasons for the restatement and (b) remedial actions, if any, that should be taken.

Restatement Methodologies

Reserve Revisions. Because of concerns over our historical documentation supporting reserves and the aggressive, and sometimes unsupportable methods that were used by personnel in booking proved reserves, the methodology we adopted to restate our reserves for the years ended December 31, 2001 and 2002 and the nine months ended September 30, 2003, was a reserve reconstruction approach. Under this method, we utilized the estimated proved reserves as of December 31, 2003 that were derived from our review completed in February 2004, and then determined historical reserves by adjusting these reserves for actual historical production data and other known data to determine the reconstructed estimates of reserves at each period end. The basic assumption underlying our methodology was that the December 31, 2003 reserve report represented the most recent, reliable and available information and was our best estimate of proved reserves. That report, therefore, became the basis of our historical reserve reconstruction. We then created a reconstruction process by adding actual production volumes in prior periods, on a well by well basis, with adjustments for assets sold (the more significant sales were re-evaluated by one of our independent reserve engineers since the proved reserves that were sold were not in the December 31, 2003 reserve report and needed to be re-evaluated given the findings in the investigation) and other known information during the period such as cost and capital spending during the restatement period.

We applied the approach described above back to December 31, 2000. However, for periods prior to December 31, 2000, which were necessary to determine the impact of the reserve restatement on beginning stockholders' equity as of January 1, 2001, we did not have access to the necessary detailed electronic records to apply this methodology. This was due, in part, to some of the documentation issues identified in the investigation, and numerous changes to our personnel immediately following our past mergers, which impacted our ability to locate that historical documentation. As a result, we used our December 31, 2000 reserve levels determined by the reconstruction approach described above as the foundation for estimating reserves and related future cash flows (for ceiling test purposes) for periods prior to December 31, 2000. This estimation approach involved the use of a "reserve over production ratio" based on the reconstructed December 31, 2000 reserve estimates. The reserve over production ratio provided the estimated life of reserves based on production levels. We applied that ratio to the actual historical period production levels to calculate estimated historical reserves for each period. In determining the reserve over production ratio to use for each period, historical prices were considered since at different pricing levels, varying levels of reserves are economical to produce, which also impacted capital cost, operating cost and revenue assumptions in determining cash flows that would be derived from reserves.

Overall, our restatement approach allowed us to recalculate reasonable proved reserve estimates at the end of each quarter over the last five years. Once we determined the historical reserve levels, we then calculated our estimated future net cash flows at the end of each quarter. These revised quarterly proved reserves and the resulting discounted net cash flows were then used to perform the ceiling test, calculate our depreciation, depletion and amortization rate, income taxes and evaluate gain or loss recognition on asset sales for each quarter. Finally, we assessed the adequacy of our overall approach based on historical prices and historically capitalized costs leading up to the earliest period in which our restatement was performed. Based on that assessment, we believe the amount recorded as a retained earnings adjustment on January 1, 1999 reasonably reflects the financial statement impact of our restated reserve levels that would have occurred prior to that time.

We believe the approach used to restate our historical reserves is a reasonable approach and is appropriate in these circumstances. It is based on a current, thoroughly reviewed and well documented reserve study and reflects actual historical data. However, it does have some limitations. First, the restated reserve levels and reported earnings do not incorporate normal positive or negative revisions in reserves that could have resulted for reasons such as mechanical failures, changes in estimates or the impact of actual drilling results on proved undeveloped reserves. These are normally occurring changes to reserves estimates that, because of the methodology we used, will not be reflected during the year they actually occurred. Rather, they will be part of our beginning retained earnings adjustments. Overall, we believe their effects on our reported results would be similar. Second, because we had to use a variation of the methodology for the years 1999 and 2000, to determine the impact on our retained earnings at January 1, 2001, the restated reserves for these periods may not be comparable to the reserve amounts that would have resulted from an actual reconstruction and none of the periods would be identical to a completely re-engineered approach. Overall, however, we believe our approach, given the results of the investigation and documentation issues discussed above, provides a reasonable approach to revising our historical reserve data that presents our related historical financial results in accordance with generally accepted accounting principles.

We also considered other restatement methodologies such as re-engineering specific production and reserve areas to determine, in hindsight, where previous estimates should have been adjusted in specific periods. We rejected this approach for several reasons. First, this method would not have produced, in our view, a more accurate result than the method we adopted, particularly given our concerns with respect to the timing of when the reserves were originally recorded. Second, it was very difficult to make reasonable assessments of how specific reserves should have been booked at a particular time without being influenced by subsequent data, especially in light of the assumptions that had already been made in the reserve estimation process. Third, the investigation identified that (a) a large number of personnel were responsible for making reserve estimates and that there was not a consistent or centralized approach used in the reserve estimation process, including the assumptions used in the process or the documentation generated in support of these assumptions and (b) there was a lack of controls over inputs into the reserve data base. As a result of such factors, the integrity of the data could not be reasonably relied upon for a detailed re-engineering of reserves. Finally, the findings of the independent investigation identified that there was inadequate detailed historical, technical documentation to support the booking of certain reported reserves. Consequently, without such detailed documentation, it would be extremely difficult, and in some cases impossible, to determine with precision the appropriate time that specific reserves should have been removed from the proved reserves category.

Our reserve restatement methodology resulted in the following revisions to our proved natural gas and oil reserves (Bcfe) (Unaudited):

	As of December 31,					
	2002		2001		2000	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
U.S.						
Onshore	2,562	1,523	4,537	2,298	4,377	2,138
Offshore	912	534	1,053	567	1,247	647
Coal Seam	1,439	791	746	378	520	299
Total U.S.	4,913	2,848	6,336	3,243	6,144	3,084
International						
Canada	167	110	252	113	190	33
Brazil	100	—	87	—	120	—
Other	52	5	—	—	—	—
Total International	319	115	339	113	310	33
Natural Gas Systems	—	—	183	183	175	175
Total Worldwide	5,232	2,963	6,858	3,539	6,629	3,292

The restatement of our proved reserves also impacted previously reported items in our supplemental information on our natural gas and oil activities, including the classification of costs incurred in natural gas and oil activities between exploration or development cost. For a further discussion of our natural gas and oil reserves, see Note 30, Supplemental Natural Gas and Oil Operations.

Production and Certain Other Hedges. As stated above, we entered a series of derivative transactions related to a substantial portion of our anticipated natural gas production and certain other derivative transactions. These transactions included: (i) our Production and Pipeline segment affiliated hedges with our Merchant Energy segment; (ii) Merchant Energy's identical transaction with a third party (the hedge transaction); and (iii) Merchant Energy's offsetting transaction with the same third party (the offsetting transaction). Our historical accounting for derivative transactions (i) and (ii) above was to defer their income statement impacts until settlement of the underlying transactions. The impacts of Merchant Energy's offsetting transactions (positive or negative) were reflected in our income statement on a mark-to-market basis. Over the period from 1999 to September 30, 2003, we recognized a total of approximately $499 million, before taxes, of mark-to-market income related to the offsetting transactions while deferring a similar loss in accumulated other comprehensive income on the hedges. To restate our historical results, we reversed amounts deferred in accumulated other comprehensive income related to the hedges and reflected them on a mark-to-market basis in our income statement for each period. On a consolidated level, the effect of reversing these amounts out of accumulated other comprehensive income and into the income statement in each period did not have a material impact in that reported period's consolidated stockholders' equity. However, it did affect reported income or loss in each period. In addition, the loss of hedge accounting in historical periods affected our ceiling test calculations in those periods, resulting in additional losses. For a further discussion of the impacts of this restatement, see discussion below.

On our business segments, we evaluated whether the affected segments should reflect the affiliated transaction between Production and Merchant Energy in their individual segment results or whether we should conclude that since these derivatives did not qualify as hedges at a consolidated reporting level, they should not be reported as hedges at the individual segment level. We concluded that had we known the original transactions would not have qualified as hedges for consolidated reporting purposes, we would not have entered into the original transactions. Accordingly, for presenting our individual segment results, we reversed the impacts of the transactions that did not qualify as hedges for consolidated purposes. See Note 26 for a presentation of restated historical segment results.

Financial Impact of Restatement

The total cumulative impact of the restatements that affected our stockholders' equity as of September 30, 2003 was a reduction of approximately $2.4 billion, which includes a reduction in beginning stockholders' equity as of January 1, 2001 of approximately $2.0 billion.

The overall financial increase/(decrease) on stockholders' equity of these restatements as of each year end was as follows (in billions):

	Reserves	Hedging	Total
December 31, 2000[(1)]	$(1.3)	$(0.7)	$(2.0)
December 31, 2001	(0.4)	(0.3)	(0.7)
December 31, 2002	—	0.2	0.2
September 30, 2003	—	0.1	0.1
Total	$(1.7)	$(0.7)	(2.4)

(1) The adjustments as of December 31, 2000 represent our opening retained earnings adjustment on January 1, 2001. As to the reserve restatement, this amount represents the impact of reserve revisions in 2000 and prior years, while the adjustment for hedges relates primarily to mark to market losses during 2000.

As to the individual financial statement line items, our historical financial statements for the years ended December 31, 2002 and 2001, for each of the quarters in those years and for each quarter and the first nine months of 2003 reflect the effects of the restatement on (i) the calculation of our historical depletion expense and its effect on our cumulative effect of accounting changes for our asset retirement obligations, (ii) the amount of our quarterly full cost ceiling test charges on amounts capitalized in our natural gas and oil full cost pools, (iii) the amounts of gains or losses recorded on long-lived assets sold, (iv) the amount of mark-to-market income recognized as revenues in each period, and (v) the impact of income taxes. We did not amend our annual report on Form 10-K for the years ended December 31, 2002 and 2001, or our quarterly reports on Form 10-Q for any periods prior to December 31, 2003, and the financial statements and related financial information contained in those reports should no longer be relied upon. A summary of the effects of the restatements on reported amounts for the years ended December 31, 2002 and 2001, and for the quarterly periods during the three year periods ended December 31, 2003 is presented below. The quarterly period information for 2001 is being provided for supplemental purposes only. Also, the information in the quarterly data below represents only those income statement and balance sheet line items affected by the restatement. For additional supplemental quarterly information, see Note 29, Supplemental Selected Quarterly Financial Information (Unaudited).

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Income Statement:				
Operating revenues	$ 7,598	$ 6,917	$ 8,939	$10,214
Depreciation, depletion and amortization	1,332	1,180	1,261	1,380
Ceiling test charges[(1)]	269	128	135	2,143
Operating income (loss)	255	(263)	1,143	291
Income taxes (benefit)	(507)	(649)	242	(70)
Net income (loss)	(1,467)	(1,753)	93	(447)
Basic and diluted earnings (loss) per common share from continuing operations	(1.87)	(2.38)	0.30	(0.77)

	Year Ended December 31, 2002		Year Ended December 31, 2001	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Balance Sheet:				
Property, plant and equipment, net	$21,764	$17,892	$22,479	$18,266
Stockholders' equity[2]	8,377	5,872	9,356	6,666
Accumulated other comprehensive income (loss)[3]	(529)	(235)	157	(18)

(1) Ceiling test charges for each period were calculated based on a comparison of the overall capitalized costs to the estimated future cash flows from reserves using our restated reserve levels at then current prices and adjusting these cash flows for the impact of qualifying hedges. These calculations were performed quarterly for each period restated.

(2) The impact on stockholders' equity for the year ended December 31, 2001 includes the restatement impacts on operating revenues, depreciation, depletion and amortization, ceiling test charges and accumulated other comprehensive income (loss) during that year, as well as the adjustment to opening retained earnings for the effects of the restatement on years prior to 2001.

(3) The cumulative effect of transition adjustment recorded to accumulated other comprehensive income (loss) associated with the adoption of SFAS No. 133 on January 1, 2001 was originally reported as $1,280 million and is reported in these restated financial statements as $647 million.

	Quarters Ended (Unaudited)					
	March 31, 2003		June 30, 2003		September 30, 2003	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)					
Operating revenues	$1,925	$1,844	$1,679	$1,574	$1,539	$1,724
Depreciation, depletion and amortization[1]	360	319	361	311	328	290
Ceiling test charges	—	1	—	20	2	47
Operating income (loss)[1]	318	268	(211)	(294)	272	447
Income taxes (benefit)	(105)	(105)	(373)	(409)	15	21
Cumulative effect of accounting changes, net of income taxes	(22)	(9)	—	—	—	—
Net income (loss)[1]	(394)	(431)	(1,188)	(1,236)	(146)	24
Basic and diluted earnings (loss) per common share from continuing operations[1]	(0.25)	(0.33)	(0.45)	(0.53)	(0.16)	0.12

(1) Our "as reported" depreciation, depletion and amortization, operating income (loss), income taxes (benefit), net loss and basic and diluted loss per common share from continuing operations differ from those amounts originally included in our March 31, 2003 Form 10-Q by $(1) million, $257 million, $(28) million and $0.38 per share due to reclassifications of our petroleum markets business as discontinued operations and other minor reclassifications, which had no impact on previously reported net income or stockholders' equity.

	Quarters Ended (Unaudited)							
	March 31, 2002		June 30, 2002		September 30, 2002		December 31, 2002	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)							
Operating revenues	$2,916	$2,478	$1,821	$1,750	$1,696	$1,615	$ 1,165	$ 1,074
Depreciation, depletion and amortization	350	297	334	281	316	295	332	307
Ceiling test charges	33	27	234	98	—	—	2	3
Operating income (loss)	985	515	296	414	310	250	(1,336)	(1,442)
Income taxes (benefit)	78	(26)	26	48	16	(7)	(627)	(664)
Net income (loss)	383	107	(45)	51	(69)	(106)	(1,736)	(1,805)
Basic and diluted earnings (loss) per common share from continuing operations	0.32	(0.20)	0.11	0.29	0.04	(0.02)	(2.19)	(2.31)

	Quarters Ended (Unaudited)							
	March 31, 2001		June 30, 2001		September 30, 2001		December 31, 2001	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
	(In millions)							
Operating revenues	$2,517	$2,702	$2,347	$3,182	$2,071	$2,536	$2,004	$1,794
Depreciation, depletion and amortization	306	335	306	345	324	408	325	292
Ceiling test charges	—	115	—	66	135	1,952	—	10
Operating income (loss)	(190)	(150)	125	856	498	(938)	710	523
Income taxes (benefit)	(27)	(19)	(51)	214	88	(451)	232	186
Net income (loss)	(400)	(367)	(93)	371	211	(685)	375	234
Basic earnings (loss) per common share from continuing operations	(0.74)	(0.68)	(0.16)	0.76	0.49	(1.29)	0.71	0.43
Diluted earnings (loss) per common share from continuing operations	(0.74)	(0.68)	(0.16)	0.73	0.47	(1.29)	0.70	0.43

The restatement of our historical reserve estimates, our historical financial information derived from those estimates and the restatement associated with our production hedges and certain other derivative transactions resulted in a delay in the filing of our annual financial statements for the year ended December 31, 2003, and resulted or will result in a delay in the filing of our Forms 10-Q for the quarterly periods ended March 31, 2004, June 30, 2004 and September 30, 2004. Furthermore, these restatements, and ongoing reviews and investigations by the SEC, the U.S. Attorney and other regulators into these restatements, could further limit or delay our ability to quickly access the capital markets in the near term. Finally, two of our wholly owned subsidiaries, El Paso CGP Company and El Paso Production Holding Company, were also impacted by the restatement for reserve revisions and their historical results were also restated and El Paso Production Holding Company was restated for certain of the derivative transactions.

The restatement will result in a lower depletion rate and reduced exposure to ceiling test charges in the future than would have been the case absent the restatement. In addition, the restatement did not have any impact on our consolidated cash flows.

Liquidity

Business Update

The year ended December 31, 2003 was a year of significant change in our business strategy and our financial condition. In late 2002, we designed a plan to realign our businesses and to take advantage of our core competencies, to significantly reduce our outstanding liabilities and to improve our liquidity. While our credit ratings continued to be below investment grade throughout 2003, we made significant progress in the areas outlined in that plan by:

- completing or announcing sales of assets and investments of approximately $6.6 billion in 2003 and into 2004 (see Note 4);
- completing financing transactions of approximately $3.8 billion as of December 31, 2003 (see Note 20);
- retiring or refinancing approximately $7.0 billion of maturing debt, other obligations and preferred securities ($5.8 billion as of December 31, 2003), including:
  - retiring long-term debt of $3.7 billion ($2.8 billion as of December 31, 2003) (see Note 20);
  - repaying $900 million of outstanding amounts under our $3 billion revolving credit facility (net repayments of $650 million as of December 31, 2003) (see Note 20);
  - redeeming $980 million of obligations under our Trinity River financing arrangement with proceeds from a $1.2 billion term loan, and then refinancing that term loan to eliminate its 2004 and 2005 amortization requirements (see Note 21);

- eliminating a $1 billion financial obligation through the purchase and consolidation of the third-party equity interests in our Gemstone and Chaparral power investments (see Note 3);
- redeeming preferred interests in Coastal Securities Company Limited for $100 million (see Note 21);
- exchanging common stock and cash for 53 percent of our outstanding equity security units which reduced our outstanding debt balances by approximately $303 million (see Note 24); and

• finalizing the Western Energy Settlement, which substantially resolved our principal exposure relating to the western energy crisis and raising funds to satisfy a significant portion of our obligations under this settlement (see Notes 6 and 22).

In mid-2003, we began to work on a Long-Range Plan, which we publicly presented on December 15, 2003. This plan, among other things, defined our core businesses, established a timeline for further debt reductions and sales of non-core businesses and assets and set financial goals for the future.

Liquidity Update

As discussed above, we restated our historical financial statements to reflect a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges primarily associated with our anticipated natural gas production.

We believe that a material restatement of our financial statements would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions; specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our $3 billion revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension with various lenders until November 30, 2004 to file our first and second quarter 2004 Forms 10-Q, which we expect to meet. If we are unable to file these Forms 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our $3 billion revolving credit facility and various other transactions could be accelerated. As part of obtaining these waivers, we also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default and limitations on our ability as well as that of our subsidiaries, to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our $3 billion revolving credit facility could constitute an event of default under some of our other debt agreements. In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

We have a $3 billion revolving credit facility that matures on June 30, 2005. The facility is collateralized by our equity interests in TGP, EPNG, ANR, CIG, Southern Gas Storage Company, ANR Storage Company and our Series A common units and Series C units in Gulf Terra. We are in the process of negotiating the refinancing of this facility and currently expect to be successful in obtaining this refinancing. Our cash sources as of June 30, 2004 include our available capacity under our revolving credit facility. In the event we are unable to refinance our existing $3 billion revolving credit facility by June 30, 2005, we would be obligated to repay the outstanding amounts, and make alternative arrangements for the letters of credit issued pursuant to this credit facility. As of June 30, 2004, we had borrowed $600 million and had approximately $1.1 billion of letters of credit issued under this credit facility.

Although we expect to successfully refinance all or a portion of our existing $3 billion revolving credit facility, if we were unsuccessful, we believe we could adjust our planned capital expenditures and increase our planned asset sales to meet any shortfall in liquidity and at the same time provide for the operations of El Paso. Further, if we were required to repay our obligations under the $3 billion revolving credit facility, some of the assets that currently collateralize this facility, including our equity interests in TGP, EPNG, ANR, CIG, Southern Gas Storage Company, ANR Storage Company and some of our Series A common units in GulfTerra, would become available to support new financing transactions. Although we cannot guarantee the outcome of future events, we believe that this available collateral would be adequate to provide financing sufficient to meet our liquidity needs.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indenture. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived the financial filing requirements through December 31, 2004. The filing of our first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the events of non-compliance resulting from our failure to file financial statements on these subsidiaries. In addition, neither we nor any of our subsidiaries have received a notice of the default caused by our failure to file our financial statements or the financial statements of our subsidiaries also impacted by the restatement. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

Furthermore, a material restatement of our financial statements for the period ended December 31, 2001 could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004. Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

Our subsidiaries are a significant potential source of liquidity to us, and they participate in our overall 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 it or it provides cash to us. If we were to incur an event of default under our credit facilities, we would be unable to obtain cash from our pipeline subsidiaries, which are the primary source of cash under this program. Currently, one of our subsidiaries, CIG, is not advancing funds to us via our cash management program due to its expected cash needs. In addition, our ownership in a number of our subsidiaries and investments serve as collateral under our revolving credit facility and our other borrowings. If the lenders under the credit facility or those other borrowings were to exercise their rights to this collateral, we could be required to liquidate these investments.

If, as a result of the events described above, we were subject to voluntary or involuntary bankruptcy proceedings, our creditors could attempt to make claims against our subsidiaries, including claims to substantively consolidate those subsidiaries. We believe that claims to substantively consolidate our subsidiaries would be without merit. However, there is no assurance that our creditors would not advance such a claim in a bankruptcy proceeding. If our creditors were able to substantively consolidate our subsidiaries in a bankruptcy proceeding, it could have a material adverse effect on our financial condition and our liquidity.

Despite the events described above, we believe we will be able to meet our liquidity and cash needs for the remainder of 2004 and through June 2005 through a combination of sources, including cash on hand, cash generated from our operations, borrowings under our $3 billion revolving credit facility, proceeds from asset sales, reduction of discretionary capital expenditures and the possible issuance of long-term debt, and common or preferred equity securities. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans.

2. Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our results for all periods presented reflect our 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 income or stockholders' equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity. Discussed in *New Accounting Pronouncements Issued But Not Yet Adopted* is a standard that, once effective, will impact our consolidation principles.

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 and MPC follow the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. ANR, CIG and WIC 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. In the fourth quarter of 2003, CIG and WIC began re-applying the provisions of SFAS No. 71 (see Note 17 for a further discussion).

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, 2003, we had $590 million of restricted cash in current assets and $349 million in other non-current assets and as of December 31, 2002, we had $124 million of restricted cash in current assets and $212 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 6.

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. 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[1]	Composite	1-57
Non-SFAS No. 71	Straight-line	1-64
Unregulated systems		
Transmission and storage facilities	Straight-line	59
Power facilities	Straight-line	5-33
Gathering and processing systems	Straight-line	3-40
Transportation equipment	Straight-line	3-30
Buildings and improvements	Straight-line	3-40
Office and miscellaneous equipment	Straight-line	2-10

(1) For our regulated interstate systems that apply SFAS No. 71, 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 accounted for under SFAS No. 71, 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. When we retire regulated property, plant and equipment not accounted for under SFAS No. 71 and non-regulated properties, we reduce property, plant and equipment for its original cost, less accumulated depreciation and salvage value, with any remaining gain or loss recorded in income.

We capitalize a carrying cost on funds invested in our construction of long-lived assets. This carrying cost consists of (i) an interest cost on the investment financed by debt, which applies to both regulated and non-regulated transmission businesses and (ii) a return on the investment financed by equity, 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, 2003, 2002 and 2001, were $34 million, $32 million and $63 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, 2003, 2002 and 2001 were $19 million, $8 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 Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* to account for asset impairments. Under this standard, we evaluate an asset for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of the asset's carrying value based on its ability to generate future cash flows on an undiscounted basis. When 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 the estimated sales price, less costs to sell. Our fair value estimates are continually updated and are generally based on market data obtained through the sales process and 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 productive and nonproductive 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 all 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 the adoption of 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 equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as 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, we recognize goodwill separately from other intangible assets. In addition, goodwill and intangibles that have indefinite lives are not amortized. Also, goodwill and indefinite lived intangible assets are periodically tested for impairment, at least annually, and whenever an event occurs that indicates that an impairment may have occurred. We adopted these standards on January 1, 2002 and stopped amortizing goodwill, and reported a pretax and after-tax gain of $154 million as a cumulative effect of accounting change in 2002 for the elimination of negative goodwill.

The net carrying amounts of our goodwill as of December 31, 2003 and 2002, and the changes in the net carrying amounts of goodwill for the years ended December 31, 2003 and 2002 for each of our segments are as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other	Total
			(In millions)			
Balances as of January 1, 2002	$413	$ 61	$474	$ 89	$ 168	$1,205
Impairments of goodwill	—	—	—	(44)	—	(44)
Other changes	—	1	9	—	(5)	5
Balances as of December 31, 2002	413	62	483	45	163	1,166
Additions to goodwill	—	—	—	22	—	22
Impairments of goodwill	—	(75)	—	(22)	(163)	(260)
Dispositions of goodwill	—	—	—	(42)	—	(42)
Other changes	—	13	(3)	—	—	10
Balances as of December 31, 2003	$413	$ —	$480	$ 3	$ —	$ 896

In May 2003, our Merchant Energy segment recorded $22 million of goodwill in connection with the acquisition of Chaparral. In December 2003, our Board of Directors approved the sale of a significant number of Chaparral's power plants, and based on the bids received we determined that the goodwill recorded on Chaparral was not recoverable and we fully impaired the related $22 million of goodwill. In this segment, we also disposed of $42 million of goodwill related to the sale of our financial services businesses. During 2002, Merchant Energy impaired $44 million of goodwill associated with its financial services businesses. This impairment resulted from the combined effects of weak industry conditions and our decision not to invest further capital in those businesses.

We also impaired $163 million of goodwill in 2003 related to our telecommunications business in our corporate activities due to weak industry conditions. Our Production segment also impaired $75 million of goodwill in 2003 which resulted from its decision to reduce its involvement in its Canadian production operations.

Our other intangible assets consist of customer lists, our general partnership interest in GulfTerra and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life excluding our excess investment in our general partnership interest in GulfTerra which has been determined to have an indefinite life. The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of December 31:

	2003	2002
	(In millions)	
Intangible assets subject to amortization	$ 29	$ 49
Accumulated amortization	(18)	(28)
Intangible assets subject to amortization, net	11	21
Intangible assets not subject to amortization	181	181
Total intangible assets, net	$192	$202

Amortization expense of our intangible assets subject to amortization was $9 million for each of the years ended December 31, 2003 and 2002. For the year ended December 31, 2001, amortization of all intangible assets, including goodwill, was $55 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense is approximately $1 million for each of the next five years. These amounts may vary as a result of future acquisitions, dispositions and any recorded impairments.

The following table presents our loss before extraordinary items and the cumulative effect of accounting changes, net income and basic and diluted earnings per common share for the year ended December 31, 2001, as if goodwill and other indefinite-lived intangibles had not been amortized during that year compared to results as actually reported:

	December 31,	
	2001 (Restated)	2001 Pro forma (Restated)
	(In millions, except per common share amounts)	
Loss before extraordinary items and cumulative effect of accounting changes	$ (473)	$ (473)
Amortization of goodwill and indefinite-lived intangibles	—	35
Adjusted loss before extraordinary items and cumulative effect of accounting changes	$ (473)	$ (438)
Net loss	$ (447)	$ (447)
Amortization of goodwill and indefinite-lived intangibles	—	35
Adjusted net loss	$ (447)	$ (412)
Basic and diluted loss per common share:		
Loss before extraordinary items and cumulative effect of accounting changes	$(0.94)	$(0.94)
Amortization of goodwill and indefinite-lived intangibles	—	0.07
Adjusted loss before extraordinary items and cumulative effect of accounting changes per share	$(0.94)	$(0.87)
Basic and diluted loss per common share:		
Net loss	$(0.89)	$(0.89)
Amortization of goodwill and indefinite-lived intangibles	—	0.07
Adjusted net loss per share	$(0.89)	$(0.82)

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.

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 physical sales of natural gas, oil and natural gas liquids produced. 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.

Merchant Energy revenues. Our Merchant Energy segment derives revenues from physical sales of natural gas and power and the management of its 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. On January 1, 2001, we adopted SFAS No. 133 and recorded a cumulative-effect adjustment of $647 million (restated — see Note 1), net of income taxes, in accumulated other comprehensive income (loss) to recognize the fair value of all derivatives designated as hedging instruments on that date. The majority of the initial cumulative-effect adjustment related to cash flow hedges on anticipated sales of natural gas. During the year ended December 31, 2001, $602 million (restated — see Note 1), net of income taxes, of this initial adjustment was reclassified to earnings as a result of completed sales and purchases during that year. See Note 15 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 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 adjustment to our natural gas inventories and exchanges and $225 million which was the 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 fuel 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). Net presentation of these historical trading activities began on July 1, 2002 with our adoption of EITF Issue No. 02-3 and all periods reflect this presentation. Prior to its adoption, we reflected these activities on a gross basis (physically settled revenues separate from physically settled expenses). Upon its adoption, revenues and costs for the year ended December 31, 2001 were revised as follows (in millions):

Gross operating revenues	$ 38,100
Costs reclassified	(27,886)
Net operating revenues reported in the income statement	$ 10,214

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 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 report current income taxes based on our 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 2003, 2002 and 2001. 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 in other expense. For the years ended December 31, 2003, 2002 and 2001, we recorded net foreign currency losses of $100 million, $91 million and $10 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 included as a separate component of accumulated other comprehensive income (loss) in stockholders' equity. The cumulative currency translation gain (loss) recorded in accumulated other comprehensive income (loss) was $44 million and $(115) million at December 31, 2003 and 2002. 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, 2003, and 2002, were approximately 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 option grants using SFAS No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the income (loss) and per share impacts of stock-based compensation 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,		
	2003	2002 (Restated)	2001 (Restated)
	(In millions, except per common share amounts)		
Net loss, as reported	$(1,928)	$(1,753)	$ (447)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	38	47	43
Deduct: Total stock-based employee compensation determined under fair value-based method for all awards, net of taxes	(88)	(169)	(178)
Pro forma net loss	$(1,978)	$(1,875)	$ (582)
Loss per share:			
Basic and diluted, as reported	$ (3.23)	$ (3.13)	$(0.89)
Basic and diluted, pro forma	$ (3.31)	$ (3.35)	$(1.15)

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. This liability is recorded at its estimated fair value, 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. We also recorded property, plant and equipment of $208 million and asset retirement obligations of $222 million as of January 1, 2003. These amounts have been restated to reflect the impact of our reserve revisions on the timing of the settlement of our asset retirement obligations, as described in Note 1. 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 ten years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells. The net asset retirement liability as of January 1, 2003 and December 31, 2003, 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, 2003, were as follows (in millions):

Net asset retirement liability at January 1, 2003	$222
Liabilities settled in 2003	(50)
Accretion expense in 2003	23
Liabilities incurred in 2003	12
Changes in estimate	13
Net asset retirement liability at December 31, 2003	$220

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, 2001, our aggregate current and non-current retirement liabilities on that date would have been approximately $180 million and our income from continuing operations and net income for the years ended December 31, 2002 and 2001, would have been lower by $13 million in each year. Basic and diluted earnings per share for the years ended December 31, 2002 and 2001, 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. For the year ended December 31, 2003, total dividends were $40 million, of which $20 million were recorded in interest expense and $20 million were recorded as distributions on preferred interests in our income statement.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2003, there were several accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of a significant standard that will impact us.

Consolidation of Variable Interest Entities. In January 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 and/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 and/or returns, including fees paid by the entity. In December 2003, the FASB issued FIN No. 46-R, which amended FIN No. 46 to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities. In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures or other entities that meet the characteristics of businesses.

On January 1, 2004, we adopted this standard. Upon adoption, we deconsolidated a previously consolidated entity, EMA Power Limited, a company that owns a power generation facility in Hungary, and consolidated Blue Lake Gas Storage Company, an equity investment that owns the Blue Lake natural gas storage facility, and several other minor entities. The overall impact of these consolidations and deconsolidation is described in the following table:

	Increase/(Decrease) (in millions)
Restricted cash	$ 34
Accounts and notes receivable from affiliates	(54)
Investments in unconsolidated affiliates	(9)
Property, plant, and equipment, net	37
Other current and non-current assets	(10)
Long-term financing obligations	15
Other current and non-current liabilities	(4)
Minority interest of consolidated subsidiaries	(13)

3. 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 2003, we recorded an impairment of our investment in Chaparral of $207 million before income taxes as further discussed in Note 28.

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 2 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

During the second quarter of 2003, we amended several financing and other agreements in connection with our new $3 billion revolving credit agreement (see Note 20). These amendments were completed to (i) simplify our capital structure by eliminating several "off-balance sheet" obligations and replace them with direct obligations, and (ii) strengthen the overall collateral package available to our financial lenders. These amendments are discussed below:

Lakeside. 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 new $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. 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.

Aruba. We amended an operating lease at our Aruba facility to provide a full guarantee to the parties who 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 new 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, increasing our total property, plant and equipment by $370 million (prior to an impairment charge we recorded on these assets of $50 million) and increasing our long-term debt by $370 million. As a result of our intent to exit substantially all of our petroleum markets operations, these leased assets and associated debt were reclassified as discontinued operations. The sale of the Aruba refinery closed in March 2004 and the $370 million obligation was repaid with proceeds from the sale.

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 20 and 21).

4. Divestitures

During 2002, 2003 and 2004, we completed or announced the sale of a number of assets and investments in each of our business segments as follows:

Segment	Proceeds[1] (In millions)	Significant Assets and Investments
Announced to date or completed in 2004		
Pipelines	$ 55	• Australian pipelines[2]
		• Equity interest in gathering systems
Production	410	• Natural gas and oil properties in Canada[2]
		• International exploration and production assets[2]
Field Services	1,020	• Effective ownership of 50 percent of general partnership interest in GulfTerra, common units and all Series C units
		• South Texas processing plants
Merchant Energy	876	• 25 domestic power plants under contract for sale[3]
		• Equity interest in the Bastrop Company power investment[2]
		• 5 other domestic power plants[2]
		• Utility Contract Funding (UCF)[2][4]
Corporate and Other	16	• Aircraft[2]
Total continuing	2,377	
Discontinued	905	• Aruba and Eagle Point refineries and other petroleum assets[2]
Total	$3,282	

(1) Amounts on sales that have been announced or are under contract for sale are estimates, subject to customary regulatory approvals, final sale negotiations and other conditions.
(2) These sales were completed in 2004.
(3) The sales of 17 of these plants were completed in 2004.
(4) We sold our ownership interests in UCF in 2004 for $21 million in cash to an affiliate of Bear Stearns, which also assumed $815 million of UCF debt. We incurred a loss of approximately $100 million on this sale in 2004.

Segment	Proceeds (In millions)	Significant Assets and Investments
Completed in 2003		
Pipelines	$ 145	• Equity interest in Alliance Pipeline System and related assets
		• Horsham pipeline in Australia
		• Equity interest in Portland Natural Gas Transmission System
Production	734	• Natural gas and oil properties located in western Canada, Texas, Louisiana, New Mexico, Oklahoma and the Gulf of Mexico
Field Services	753	• Gathering systems located in Wyoming
		• Midstream assets in the north Louisiana and Mid-Continent regions
		• Common and Series B preference units in GulfTerra
		• 50 percent of general partnership interest in GulfTerra

Segment	Proceeds (In millions)	Significant Assets and Investments
Merchant Energy	853	• Equity interest in the CE Generation, L.L.C. power investment • Enerplus Global Energy Management Company and its financial operations • EnCap funds management business and certain related investments • CAPSA/CAPEX and Costañera investments in Argentina • East Coast Power, L.L.C.
Corporate and Other	64	• Aircraft
Total continuing[(1)]	2,549	
Discontinued[(2)]	747	• Corpus Christi refinery, Florida petroleum terminals and other coal and petroleum assets
Total	$3,296	

(1) Includes $20 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with the assets sold.

(2) Includes $84 million of proceeds related to the sale of our asphalt facilities, which includes $39 million of cash, $27 million of accounts and notes receivable, and the release of $18 million of previously outstanding liabilities. In December 2003, we recorded a valuation allowance of $17 million on these receivables, reducing them to their net realizable value. We continue to evaluate the financial condition of the purchaser in order to determine whether an additional valuation allowance on the receivables is necessary.

Segment	Proceeds (In millions)	Significant Assets and Investments
Completed in 2002		
Pipelines	$ 303	• Natural gas and oil properties located in Texas, Kansas and Oklahoma and their related contracts • 12.3 percent equity interest in Alliance Pipeline and related assets • Typhoon natural gas pipeline
Production	1,297	• Natural gas and oil properties located in Texas, Colorado, Utah and western Canada
Field Services	1,513	• Texas and New Mexico midstream assets • Dragon Trail gas processing plant • San Juan Basin gathering, treating and processing assets • Gathering facilities located in Utah
Merchant Energy	90	• 40 percent equity interest in the Samalayuca Power II power project in Mexico
Total continuing[(1)]	3,203	
Discontinued	128	• Coal reserves and properties and petroleum assets
Total	$3,331	

(1) Includes the receipt of $350 million of Series C units, a non-voting class of the limited partnership interest in GulfTerra, from the sale of assets in our Field Services segment and $27 million of costs incurred in preparing assets for disposal, returns of invested capital and cash transferred with the assets sold.

During the years ended December 31, 2003, 2002 and 2001, our asset impairments and net realized gain and loss on long-lived assets were $949 million, $185 million and $77 million, and our impairments and net realized loss on sales of investments were $176 million, $624 million and $46 million. These gains, losses and asset impairments are discussed in Notes 7 and 28.

For the year ended December 31, 2001, we sold our Midwestern Gas Transmission system, our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems, and our investments in the Empire State and Iroquois pipeline systems. Net proceeds from these sales were approximately $279 million, and we recognized extraordinary net gains of approximately $26 million, net of income taxes of approximately $27 million. These gains were treated as extraordinary since they resulted from a Federal Trade Commission (FTC) order in connection with our merger in 2001 with Coastal.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets being disposed of that have received appropriate approvals by our management and/or Board of Directors and that have met other criteria as held for sale or, if appropriate, discontinued operations. As of December 31, 2003 and 2002, we had $903 million and $31 million of net assets and liabilities held for sale reflected in our balance sheet. Of the net assets and liabilities held for sale as of December 31, 2003, $710 million was related to the announced sales of our domestic power plants and $193 million was related to the announced sale of our south Texas processing plants and the remaining domestic power assets that were approved by our Board of Directors for sale in 2003. Our assets held for sale at December 31, 2002 related to $31 million of gathering assets in our Field Services segment all of which were sold during 2003. The following table details the items that have been reflected as current assets and liabilities held for sale in our balance sheets as of December 31:

	2003	2002
	(In millions)	
Assets Held for Sale		
Current assets	$ 44	$—
Assets from price risk management activities, current	2	—
Investments in unconsolidated affiliates	480	—
Property, plant and equipment, net	477	31
Assets from price risk management activities, non-current	11	—
Intangible assets, net	11	—
Other assets	114	—
Total assets	$1,139	$31
Liabilities related to Assets Held for Sale		
Current liabilities	$ 54	$—
Long-term debt, less current maturities	169	—
Other liabilities	13	—
Total liabilities	$ 236	$—

We continue to evaluate assets we may sell or otherwise divest of in the future. As specific assets are identified for divestiture, we will be required to record them at the lower of fair value, less selling costs, or historical cost. This will require us to assess them for possible impairment. These impairment charges, if any, will generally be based on their estimated fair value as determined by market data obtained through the divestiture process or by assessing the probability-weighted cash flows of the asset. For a discussion of impairment charges incurred on our long-lived assets, see Note 7; for impairments on discontinued operations, see Note 12; and for impairments on our investments in unconsolidated affiliates, see Note 28.

5. Restructuring and Merger-Related Costs

Restructuring Costs. As part of our balance sheet and liquidity enhancement actions taken in 2002 and 2003, 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 in 2003 and 2002 were as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other	Total
			(In millions)			
2003						
Employee severance, retention and transition costs	$ 2	$ 6	$ 4	$22	$ 42	$ 76
Contract termination and other costs	—	—	—	48	—	48
	$ 2	$ 6	$ 4	$70	$ 42	$124
2002						
Employee severance, retention and transition costs	$ 1	$—	$ 1	$24	$ 11	$ 37
Transaction costs	—	—	—	—	40	40
	$ 1	$—	$ 1	$24	$ 51	$ 77

The 2003 restructuring costs were incurred as part of our ongoing liquidity enhancement and cost reduction efforts. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. During 2003, we eliminated approximately 900 full-time positions from our continuing businesses and approximately 1,800 positions related to businesses we discontinued. Of the $76 million employee severance costs in our continuing businesses, $54 million were paid as of December 31, 2003. In addition, substantially all of the costs related to our discontinued operations, which totaled $12 million, were paid as of December 31, 2003. As of June 30, 2004, we incurred an additional $33 million of employee severance costs as part of our ongoing liquidity enhancement and cost reduction efforts. Our contract termination and other costs included charges of approximately $44 million related to amounts paid for cancelling or restructuring our obligations to charter a fifth ship to transport LNG from supply areas to domestic and international market centers.

During 2002, we completed an employee restructuring across all of our operating segments which resulted in a reduction of approximately 900 full-time positions through terminations. As a result of these actions, we incurred $37 million of employee severance and termination costs, which have been paid. We also incurred and paid fees of $40 million to eliminate stock price and credit rating triggers related to our Chaparral and Gemstone investments.

Merger-Related Costs. During 2001, we incurred merger-related costs in connection with our Coastal merger as follows:

	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other	Total
			(In millions)			
Employee severance, retention and transition costs	$ 83	$ 7	$ 5	$ 2	$ 725	$ 822
Transaction costs	—	—	—	—	70	70
Business and operational integration costs	178	17	—	—	188	383
Other	30	23	41	15	109	218
	$291	$47	$46	$17	$1,092	$1,493

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. As a result of these actions, employee severance, retention and transition costs for 2001 were approximately $822 million, which included $214 million of pension and post-retirement benefits which will be paid over the applicable benefit periods of the terminated and retired employees and a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares. All other costs were expensed and paid as incurred.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our mergers. All of these costs were expensed and paid as incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments. Total charges in 2001 were $383 million, which primarily included: (i) $153 million related to a charge from a mark-to-market loss on an energy-related contract for transportation capacity on the Alliance Pipeline, (ii) $15 million of incremental fees under software and seismic license agreements which were recorded in our Production segment, (iii) $222 million of estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado. The lease-related costs were accrued at the time we completed our relocations and closed these offices and will be paid over the term of the applicable non-cancelable lease agreements. All other costs were expensed and paid as incurred.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of our merger with Coastal and other miscellaneous charges. As part of the FTC order related to our merger with Coastal, GulfTerra was required to sell its interests in seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from the sales of these assets were approximately $135 million and resulted in a loss to the partnership of approximately $25 million. As consideration for these sales, we committed to pay GulfTerra a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by GulfTerra. We expensed this commitment.

6. Western Energy Settlement

In June 2003, we entered into two definitive agreements (referred to as the Western Energy Settlement) with a number of public and private claimants, including the states of California, Washington, Oregon and Nevada, to resolve the principal litigation, claims and regulatory proceedings against us and our subsidiaries relating to the sale or delivery of natural gas and electricity from September 1996 to the date of the settlement. These agreements modified an agreement in principle entered into on March 20, 2003. Subject to court and regulatory approvals, which have now been received, the settlement includes payments of cash, proceeds from the issuance of common stock and the reduction in prices under a power supply contract. Below is an analysis of our obligations on a discounted basis under the definitive settlement agreements as of December 31, 2003:

Obligations	Current	Long-Term (In millions)	Total
Cash payments of $45 million per year for 20 years	$ 22	$370	$ 392
Price reduction on power supply contract	71	45	116
Proceeds from issuance of common stock	195	—	195
Cash payments	345	—	345
Total	$633	$415	$1,048

Upon the initial agreement in principle, we recorded an initial pretax charge and discounted obligation of $899 million ($1,690 million undiscounted) in December 2002. Upon entering the definitive agreements and during the remainder of 2003, we recorded an increase in this obligation and a pretax charge of $104 million. The adjustment was primarily a result of changes in the timing of settlement payments and changes in the value of the common stock to be issued in connection with the definitive settlement agreements. During 2003, we also recorded $66 million of additional charges, including $51 million of accretion expense on the discounted Western Energy Settlement obligation and other charges of $15 million, all of which were included as part of operation and maintenance expense in our income statement. As of December 31, 2003, $10 million of the total obligation had been satisfied. For issues regarding the potential tax deductibility of our Western Energy Settlement charges, see Note 11.

We established an escrow account for amounts funded by us until final approval of the settlement agreements was received. As of December 31, 2003, total amounts in this account were $468 million, which were reflected as restricted cash in our balance sheet and as an investing activity in our statement of cash flows. We funded $322 million of this account with a majority of the net proceeds from the issuance of senior notes in July 2003 by EPNG, our subsidiary, and through the issuance of a total of 17.6 million shares of our common stock for $121 million in 2003. In 2004, we made additional deposits into the escrow account, including proceeds from the issuance of the remaining 8.8 million shares under our stock obligation for approximately $74 million. As noted below, upon final approval of the settlement in June 2004, the amounts in escrow were released and will be reflected as an addition to our cash flows from investing activities.

The settlement became effective in June 2004, upon which approximately $602 million was released to the California claimants, which included $568 million of previously escrowed funds and a $12 million prepayment of a portion of our 20 year obligation. Upon release of these amounts, we reduced our liability which will be reflected as a reduction in our cash flow from operations in the second quarter of 2004. As of June 30, 2004, our remaining obligation consisted of $75 million under a power supply contract over its remaining term and our remaining 20-year cash payment obligation for approximately $876 million. In connection with the settlement, we provided collateral in the form of natural gas and oil properties to secure our remaining 20 year payment obligation of approximately $44 million per year. The initial collateral requirement was approximately $592 million and will be reduced as payments are made under the 20-year obligation. For further information on the Western Energy Settlement, see Note 22.

7. 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 loss on long-lived assets were as follows:

	2003	2002	2001
		(In millions)	
Net realized (gain) loss	$ 69	$(259)	$ 2
Asset impairments			
Merchant Energy			
LNG assets	33	—	—
Power assets	180	162	—
Other	—	44	21
Field Services			
South Texas processing assets	167	—	—
North Louisiana gathering facility	—	66	—
Other	4	—	—
Production			
Canadian assets	14	4	—
Australian and Indonesian assets	—	—	16
Goodwill impairment	75	—	—
Other	10	—	—
Pipelines			
Other	—	—	22
Corporate			
Telecommunications assets	396	168	12
Other	1	—	4
Total asset impairments	880	444	75
Loss on long-lived assets	$949	$ 185	$ 77

Net Realized (Gain) Loss

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 (see Note 28, Investments in and Advances to Unconsolidated Affiliates), 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 and a $10 million loss on the sale of Mohawk River Funding I in our Merchant Energy 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 4 for a further discussion of these divestitures. Our 2001 net realized losses related to miscellaneous asset sales across all our segments.

Asset Impairments

Our impairment charges for the years ended December 31, 2003, 2002 and 2001, were recorded primarily based on our intent to dispose of, or reduce our involvement in, a number of assets as part of our liquidity enhancement efforts. 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 probability-weighted scenarios 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. Our Production charges include the writedown of $75 million of goodwill in 2003. Our ability to recover this amount was impaired based on our decision to reduce our involvement in our Canadian production operations. Our Field Services charges include 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 28) and a $66 million impairment that resulted from our decision to sell our north Louisiana gathering facilities in 2002. Our 2003 and 2002 Merchant Energy charges were primarily a result of our plan to reduce our involvement in the LNG business and our planned sale of domestic power assets (including our turbines classified in long-term assets).

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 12 and 28. For additional discussion on goodwill and other intangibles, see Note 2.

8. Accounting Changes

Changes in Accounting Principle

During the years ended December 31, 2003 and 2002, we recorded the following cumulative effect of accounting changes due to the adoption of new accounting pronouncements (in millions):

	Before-tax	After-tax
2003		
SFAS No. 143 (restated — See Note 1)	$ (13)	$ (9)
2002		
EITF Issue No. 02-3	$(343)	$(222)
SFAS No. 141 and 142	154	154
DIG Issue No. C-16	23	14
Total	$(166)	$ (54)

For a discussion of each of the accounting principles we adopted during 2003 and 2002, see Note 2.

Changes in Accounting Estimate

During 2001, we incurred approximately $316 million in costs related to changes in accounting estimates, which consist of $232 million in additional environmental remediation liabilities, $47 million of additional accrued legal obligations and a $37 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. Of the overall pre-tax amount, approximately $182 million of these costs were included in our continuing operation and maintenance costs and $134 million were related to our discontinued petroleum markets and coal businesses included as part of discontinued operations. Our changes in estimates reduced our overall net income by approximately $215 million, of which $124 million was related to continuing operations and $91 million was related to discontinued operations.

The change in our estimated environmental remediation liabilities was due to a number of events, including the sale of a majority of our retail gas stations, the closure of our Gulf Coast Chemical and Midwest refining operations, the lease of our Corpus Christi refinery to Valero, and conforming Coastal's methods of environmental identification, assessment and remediation strategies and processes to our historical practices following our merger with Coastal.

9. Ceiling Test Charges

See Note 1 for a discussion of the restatement of our historical reserves and Note 30 for a discussion of our natural gas and oil reserves and reserve revisions.

During the years ended December 31, 2003, 2002 and 2001, we incurred ceiling test charges in the following full cost pools:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.	$—	$ —	$1,844
Canada	61	91	225
Brazil	5	3	50
Indonesia	—	1	5
Turkey	2	24	18
Australia and other international countries	8	9	1
Total	$76	$128	$2,143

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of qualifying cash flow hedges was considered in determining our ceiling test charges, and will be factored into future ceiling test calculations. The charges for our international cost pools would not have materially changed had the impact of our hedges not been included in calculating our ceiling test charges since we do not significantly hedge our international production activities. Our 2001 U.S. charge was incurred during the third quarter of that year. Had the impact of qualifying cash flow hedges been excluded, our domestic charge would have increased by $330 million.

10. 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:

	2003	2002	2001
		(In millions)	
Other Income			
Interest income	$ 83	$ 84	$104
Allowance for funds used during construction	19	7	8
Development, management and administrative services fees on power projects from affiliates	18	21	105
Re-application of SFAS No. 71 (CIG and WIC)	18	—	—
Net foreign currency gain	12	—	—
Favorable resolution of non-operating contingent obligations	9	38	6
Gain on early extinguishment of debt	—	21	—
Gain on sale of cost basis investment	7	—	—
Other	37	26	65
Total	$203	$197	$288
Other Expenses			
Net foreign currency losses[1]	$112	$ 91	$ 10
Loss on early extinguishment of debt	37	—	—
Loss on exchange of equity security units	12	—	—
Mustang redemption charges	11	—	—
Impairment of cost basis investment[2]	5	56	66
Minority interest in consolidated subsidiaries	1	58	2
Other	24	34	50
Total	$202	$239	$128

(1) Amounts in 2003 and 2002 were primarily related to net foreign currency losses on our Euro-denominated debt.

(2) We impaired our investment in our Costañera power plant in 2002 and various telecommunication investments in 2001.

11. Income Taxes

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

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
U.S.	$(1,331)	$(2,270)	$(194)
Foreign	131	287	(264)
	$(1,200)	$(1,983)	$(458)

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:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Current			
Federal	$ 36	$ (15)	$ (88)
State	57	27	(10)
Foreign	42	32	27
	135	44	(71)
Deferred			
Federal	(652)	(655)	146
State	(57)	(11)	(24)
Foreign	(10)	(27)	(121)
	(719)	(693)	1
Total income tax benefit	$(584)	$(649)	$ (70)

Our income tax benefit, 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:

	2003	2002 (Restated)	2001 (Restated)
	(In millions, except rates)		
Income tax benefit at the statutory federal rate of 35%	$(420)	$(694)	$(160)
Increase (decrease)			
Abandonments and sales of foreign investments	(139)	—	—
Valuation allowances	(57)	44	19
Foreign income taxed at different rates	6	13	(3)
(Earnings) losses from unconsolidated affiliates where we anticipate receiving dividends	(13)	2	(20)
Non-deductible dividends on preferred stock of a subsidiary	10	10	12
Deferred credit on loss carryovers	(10)	—	(7)
State income tax, net of federal income tax effect	3	2	(22)
Non-conventional fuel tax credit	—	(11)	(6)
Non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities	—	(3)	115
Depreciation, depletion and amortization	—	1	23
Goodwill impairment	29	—	—
Other	7	(13)	(21)
Income tax benefit	$(584)	$(649)	$ (70)
Effective tax rate	49%	33%	15%

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

	2003	2002 (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$2,147	$3,154
Investments in unconsolidated affiliates	777	810
Employee benefits and deferred compensation	126	95
Regulatory and other assets	190	244
Total deferred tax liability	3,240	4,303

	2003	2002 (Restated)
	(In millions)	
Deferred tax assets		
Net operating loss and tax credit carryovers		
U.S. federal	814	925
State	146	109
Foreign	18	22
Western Energy Settlement	400	341
Environmental liability	206	201
Price risk management activities	136	308
Debt	105	59
Inventory	91	100
Deferred federal tax on deferred state income tax liability	75	67
Allowance for doubtful accounts	75	28
Other	273	397
Valuation allowance	(9)	(72)
Total deferred tax asset	2,330	2,485
Net deferred tax liability	$ 910	$1,818

Upon review of the classification of our deferred tax assets, we determined that deferred tax assets associated with our current liability for commodity-based derivatives that had historically been classified in long-term deferred income taxes should have been classified as a current asset in our consolidated balance sheet. Accordingly, we revised our consolidated balance sheets to reflect this change in classification. These revisions had no impact on our consolidated statements of income, cash flows, comprehensive income or changes in stockholders' equity. See Note 1 for a further discussion of the restatement.

Included in our deferred tax assets are amounts related to the Western Energy Settlement. Proposed tax legislation has been introduced in the U.S. Senate which would disallow deductions for certain settlements made to or on behalf of governmental entities. If enacted, this tax legislation could impact the deductibility of the expenses related to the Western Energy Settlement and could result in a write-off of some or all of the associated deferred tax assets. In such event, our tax expense would increase.

Also included in our deferred tax assets as of December 31, 2003 are amounts related to abandonments and sales of certain of our foreign investments, that have occurred in 2003, or are anticipated to occur in 2004.

At December 31, 2003, the portion of the cumulative undistributed earnings of our foreign subsidiaries and foreign corporate joint ventures on which we have not recorded U.S. income taxes was approximately $835 million. Since these earnings have been or are intended to be indefinitely reinvested in foreign operations, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustment recorded in accumulated other comprehensive income (loss).

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, increased taxes payable by $26 million in 2003 and reduced taxes payable by $15 million in 2002 and $31 million in 2001. These tax effects are included in additional paid-in capital in our balance sheets.

As of December 31, 2003, we have alternative minimum tax credits of $279 million that carryover indefinitely and $2 million of general business credit carryovers for which the carryover periods end at various times in the years 2009 through 2021. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2003:

	Carryover Period				
	2004	2005-2010	2011-2015	2016-2023	Total
			(In millions)		
U.S. federal net operating loss	$—	$ 7	$ —	$2,206	$2,213
State net operating loss	93	418	437	887	1,835

We also had $52 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, 2003, we maintained a valuation allowance of $5 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, $2 million related to U.S. federal and state net operating loss carryovers, $1 million related to foreign tax assets for ceiling test charges and $1 million related to a general business credit carryover. As of December 31, 2002, we maintained valuation allowances of $22 million related to foreign net operating loss carryovers, $34 million related to foreign deferred tax assets for ceiling test charges, $9 million related to state tax benefits from the Western Energy Settlement, $6 million related to U.S. federal and state net operating loss carryovers, and $1 million related to a general business credit carryover. The change in our valuation allowances from December 31, 2002 to December 31, 2003 is primarily related to a partial reversal of a state tax valuation allowance related to the Western Energy Settlement and a reversal of the valuation allowances on certain foreign ceiling test charges, a foreign impairment and a foreign net operating loss carryover.

12. Discontinued Operations

Petroleum Markets Operations

In June 2003, our Board of Directors authorized the sale of our petroleum markets operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. The Board's actions were in addition to previous actions approving the sales of our Eagle Point refinery, our asphalt business, our Florida terminal, tug and barge business and our lease crude operations. 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 charges during 2003 totaling $1.5 billion related to impairment of our petroleum markets assets, which included $1.1 billion related to our Aruba refinery and $264 million related to our Eagle Point refinery. These impairments were based on a comparison of the carrying value of our petroleum markets assets to their estimated fair value, less selling costs. In the first quarter of 2004, we completed the sales of our Aruba and Eagle Point refineries for $883 million and used a portion of the proceeds to repay $370 million of debt associated with these operations. The magnitude of these charges was 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 recognized $90 million of realized gains primarily on the sale of our Florida terminalling and transportation assets, asphalt facilities and chemical facilities in 2003. During 2003 and 2004 we sold substantially all of our petroleum markets assets.

Coal Mining Operations

In June 2002, our Board of Directors authorized the sale of our coal mining operations. These operations, consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following this approval, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process. Because this carrying value was higher than our estimated net sales proceeds, we recorded an impairment charge of $185 million during 2002.

In December 2002, we sold substantially all of our reserves and properties in West Virginia, Virginia and Kentucky to an affiliate of Natural Resources Partners, L.P. for $57 million in cash. In January 2003, we sold our remaining coal operations, which consisted of mining operations, businesses, properties and reserves in Kentucky, West Virginia and Virginia for $59 million which included $35 million in cash and $24 million in notes receivable. We did not record a significant gain or loss on these sales in 2002 and 2003.

Our petroleum markets operations and our coal mining operations are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of the remaining discontinued businesses are classified as current assets and liabilities as of December 31, 2003. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	Coal Mining (In millions)	Total
Operating Results			
Year Ended December 31, 2003			
Revenues[1]	$ 5,697	$ 27	$ 5,724
Costs and expenses[1]	(5,837)	(13)	(5,850)
Loss on long-lived assets	(1,404)	(9)	(1,413)
Other income (expense)	(10)	1	(9)
Interest and debt expense	(11)	—	(11)
Income (loss) before income taxes	(1,565)	6	(1,559)
Income taxes	(261)	5	(256)
Income (loss) from discontinued operations, net of income taxes	$(1,304)	$ 1	$(1,303)
Year Ended December 31, 2002			
Revenues[1]	$ 4,814	$ 309	$ 5,123
Costs and expenses[1]	(4,954)	(327)	(5,281)
Loss on long-lived assets	(97)	(184)	(281)
Other income	20	5	25
Interest and debt expense	(12)	—	(12)
Loss before income taxes	(229)	(197)	(426)
Income taxes	12	(73)	(61)
Loss from discontinued operations, net of income taxes	$ (241)	$(124)	$ (365)
Year Ended December 31, 2001			
Revenues[1]	$ 4,900	$ 277	$ 5,177
Costs and expenses[1]	(5,016)	(286)	(5,302)
Loss on long-lived assets	(106)	—	(106)
Other income	111	2	113
Interest and debt expense	(27)	—	(27)
Loss before income taxes	(138)	(7)	(145)
Income taxes	(58)	(2)	(60)
Loss from discontinued operations, net of income taxes	$ (80)	$ (5)	$ (85)

(1) These amounts include intercompany activities between our discontinued petroleum markets operations and our continuing operating segments.

	Petroleum Markets	Coal Mining	Total
		(In millions)	
Financial Position Data			
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivable	$ 262	$ —	$ 262
Inventory	385	—	385
Other current assets	131	—	131
Property, plant and equipment, net	521	—	521
Other non-current assets	70	—	70
Total assets of discontinued operations	$1,369	$ —	$1,369
Liabilities of discontinued operations			
Accounts payable	$ 172	$ —	$ 172
Other current liabilities	86	—	86
Long-term debt	374	—	374
Environmental remediation reserve	24	—	24
Other non-current liabilities	2	—	2
Total liabilities of discontinued operations	$ 658	$ —	$ 658
December 31, 2002			
Assets of discontinued operations			
Accounts and notes receivable	$1,229	$ 29	$1,258
Inventory	636	14	650
Other current assets	79	1	80
Property, plant and equipment, net	1,950	46	1,996
Other non-current assets	65	16	81
Total assets of discontinued operations	$3,959	$106	$4,065
Liabilities of discontinued operations			
Accounts payable	$1,153	$ 20	$1,173
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities of discontinued operations	$1,420	$ 40	$1,460

13. Earnings Per Share

Our basic and diluted earnings (loss) per share were the same in each period presented because we had net losses from continuing operations. We calculated basic and diluted earnings (loss) per share amounts as follows for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
	(In millions, except per common share amounts)		
Loss from continuing operations	$ (616)	$(1,334)	$ (388)
Discontinued operations, net of income taxes	(1,303)	(365)	(85)
Extraordinary items, net of income taxes	—	—	26
Cumulative effect of accounting changes, net of income taxes	(9)	(54)	—
Net loss	$(1,928)	$(1,753)	$ (447)

	2003	2002 (Restated)	2001 (Restated)
	(In millions, except per common share amounts)		
Average common shares outstanding	597	560	505
Effect of dilutive securities			
Restricted stock	—	—	—
Stock options	—	—	—
FELINE PRIDES[sm]	—	—	—
Average common shares outstanding	597	560	505
Losses per common share			
Loss from continuing operations	$ (1.03)	$ (2.38)	$(0.77)
Discontinued operations, net of income taxes	(2.18)	(0.65)	(0.17)
Extraordinary items, net of income taxes	—	—	0.05
Cumulative effect of accounting changes, net of income taxes	(0.02)	(0.10)	—
Net loss per common share	$ (3.23)	$ (3.13)	$(0.89)

For the year ended December 31, 2003 and 2002, there were less than 1 million shares related to our stock options, approximately 8.5 million shares related to our convertible debentures and approximately 7.8 million shares related to our trust preferred securities which were excluded from the determination of average common shares outstanding because we had net losses in these periods. Additionally, in 2003 approximately 8.8 million shares related to our remaining stock obligation under our Western Energy Settlement were excluded also due to net losses in 2003 (see Note 6 for further information).

14. Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31, 2003 and 2002. The 2002 amounts for commodity-based price risk management activities have been restated to reflect the impact of our hedge revisions on our price risk management activities, as described in Note 1.

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Investments	$ 12	$ 12	$ 43	$ 43
Long-term financing obligations, including current maturities	21,676	20,713	16,681	12,268
Notes payable to affiliates	—	—	390	380
Company-obligated preferred securities of subsidiaries(1)	—	—	625	278
Commodity-based price risk management derivatives (Restated)	1,406	1,406	422	422
Interest rate and foreign currency hedging derivatives	123	123	22	22

(1) These were reclassified as long-term financing obligations upon our adoption of SFAS No. 150 in 2003.

As of December 31, 2003 and 2002, 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 15 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

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 have net financial instrument asset exposure as of December 31, 2003 and 2002. The 2002 amounts have been restated to reflect the impact of our hedge revisions on our net exposure from financial instrument assets related to our price risk management activities.

	Net Financial Instrument Asset Exposure			
Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2003				
Energy marketers	$ 425	$ 43	$ 53	$ 521
Financial institutions	90	—	—	90
Natural gas and electric utilities	1,755	—	78	1,833
Other	16	1	75	92
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

Counterparty	Net Financial Instrument Asset Exposure Investment Grade[1]	Below Investment Grade[1] (In millions)	Not Rated[1]	Total
December 31, 2002 (Restated)				
Energy marketers	$ 476	$ 132	$ 8	$ 616
Natural gas and electric utilities	1,275	83	3	1,361
Other	95	—	5	100
Net financial instrument assets[2]	1,846	215	16	2,077
Collateral held by us	(156)	(98)	—	(254)
Net exposure from financial instrument assets	$1,690	$ 117	$ 16	$1,823

(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 100 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 U.S. Gen New England, Mirant and Enron (see Note 22), 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 66 percent and 49 percent of our net financial instrument asset exposure as of December 31, 2003 and 2002. PSEG was rated as investment grade by Moody's Investor's Services and Standard & Poor's, and we have not required any collateral from them as of December 31, 2003 and 2002. We also had one other customer, Duke Energy Trading and Marketing LLC, that comprised six percent of our net financial instrument asset exposure by counterparty as of December 31, 2003. Duke was also rated as investment grade as of December 31, 2003. In early 2004, Duke's rating was lowered to "below investment grade" by Moody's and Standard & Poor's, at which time Duke provided us a letter of credit. 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.

15. Price Risk Management Activities

In the table below, 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. The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2003 and 2002. The 2002 amounts for commodity-based price risk management activities have been restated to reflect the impact of our hedge revisions on our derivatives, as described in Note 1.

	2003	2002 (Restated)
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (31)	$ (21)
Derivatives from power contract restructuring activities[1]	1,925	968
Other commodity-based derivative contracts	(488)	(525)
Total commodity-based derivatives	1,406	422
Interest rate and foreign currency hedging derivatives	123	22
Net assets from price risk management activities[2]	$1,529	$ 444

(1) Includes $983 million of net assets from derivative contracts we acquired in connection with our acquisition of a controlling interest in Chaparral in 2003.

(2) Included in both current and non-current assets and liabilities 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 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, 2003 and 2002, we have converted approximately 275 million euros of our debt to $255 million. A summary of the impacts of our cash flow hedges included in accumulated other comprehensive loss, net of income taxes, as of December 31, 2003 and 2002 follows. The 2002 amounts have been restated to reflect the impact of our hedge revisions on our accumulated other comprehensive income(loss), as described in Note 1.

	Accumulated Other Comprehensive Income (Loss)		Estimated Loss Reclassification in 2004[1]	Final Termination Date
	2003	2002 (Restated)		
Commodity cash flow hedges				
Held by consolidated entities	$(73)	$(30)	$(16)	2012
Held by unconsolidated affiliates	13	(65)	(4)	2005
Undesignated[2]	—	5	—	2003
Total commodity cash flow hedges[3]	(60)	(90)	(20)	
Foreign currency cash flow hedges				
Fixed rate	58	14	(3)	2006
Undesignated[4]	(9)	(9)	(1)	2006
Total foreign currency cash flow hedges	49	5	(4)	
Total[5]	$(11)	$(85)	$(24)	

(1) Reclassifications occur upon the physical delivery of the hedged commodity and the corresponding expiration of the hedge.

[2] In May 2002, we announced the plan to reduce the volumes of natural gas hedged for our Production segment, and, as a result, we removed the hedging designation on these derivatives.

[3] During 2004, we entered into hedges for 5.5 TBtu of our future natural gas production at an average price of $5.64 per MMBtu and for 1.1 MMBbls of our Production segment's anticipated oil production at an average price of $35.15 per Bbl.

[4] In December 2002, we reduced the amount of foreign currency exchange risk that we have hedged for our Euro-denominated debt, and, as a result, we removed the hedging designation on these derivatives.

[5] Accumulated other comprehensive income (loss) also includes $44 million and $(115) million of currency translation adjustments and $(24) million and $(35) million of additional minimum pension liability as of December 31, 2003 and 2002.

For the years ended December 31, 2003, 2002 and 2001, we recognized a net loss of $2 million, a net loss of $4 million and a net gain of $2 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. We have derivatives with a fair value loss of $19 million as of December 31, 2003 that converted the interest rate on $350 million of our U.S. dollar denominated debt to a floating weighted average interest rate of LIBOR plus 4.2%. We also have derivatives with a fair value of $52 million as of December 31, 2003 that converted approximately 350 million euros of our debt to $390 million and also converted the interest rate on this debt to a floating weighted average interest rate of LIBOR plus 3.7%. We have recorded the fair value of those derivatives as a component of long-term debt and the related accrued interest. For the years ended December 31, 2002 and 2001, the financial statement impact of our fair value hedges was immaterial. In 2004, we entered into new hedges that converted the interest rate on an additional $90 million of our U.S. dollar denominated debt to a floating interest rate of LIBOR plus 4.3% and new hedges that converted another 100 million euros of debt to $121 million and converted the interest rate on this debt from a fixed rate to a floating interest rate of LIBOR plus 4.5%.

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 $6 million and $8 million at December 31, 2003 and 2002. 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, Merchant Energy's energy marketing and trading division 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. We also terminated a power contract at our consolidated Mount Carmel facility in exchange for a $50 million cash payment. As of and 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.

During 2003, no new power restructuring transactions were completed and, as a result, our consolidated financial statements for the year ended December 31, 2003 only reflect the change in value of the above restructured contracts and power supply contracts, and the related purchases and sales under these contracts. 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 June 2004, we completed the sale of UCF (which is the restructured Eagle Point power contract).

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 $488 million and $525 million as of December 31, 2003 and 2002.

16. Inventory

We have the following current inventory as of December 31:

	2003	2002
	(In millions)	
Materials and supplies and other	$151	$174
NGL and natural gas in storage	33	78
Total current inventory	$184	$252

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

	2003	2002
	(In millions)	
Dark fiber	$ 5	$ 5
Turbines[(1)]	98	222
Total non-current inventory	$103	$227

[(1)] In 2003 and 2002, we recorded an impairment charge related to these turbines (see Note 7).

17. 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. During 2003, CIG and WIC met the requirements to re-apply the provisions of SFAS No. 71. As a result of applying this standard, we recorded $18 million in regulatory assets and a pre-tax benefit of $18 million in our 2003 income statement. In addition, $2 million of other assets and $10 million of other liabilities were reclassified as regulatory assets/liabilities upon re-application of SFAS No. 71. Below are the details of our regulatory assets and liabilities, which represent our regulated interstate systems that apply the provisions of SFAS No. 71, as of December 31:

Description	2003	2002	Remaining Recovery Period
	(In millions)		(Years)
Current regulatory assets[(1)]	$ 2	$ 3	1
Non-current regulatory assets			
Grossed-up deferred taxes on capitalized funds used during construction[(1)]	77	59	14-29
Postretirement benefits[(1)]	32	26	7-9
Unamortized net loss on reacquired debt[(1)]	26	29	14-18
Under-collected state income tax	4	8	1-2
Under-collected federal income tax[(1)]	2	—	N/A
Other[(1)]	2	7	1-9
Total non-current regulatory assets	143	129	
Total regulatory assets	$145	$132	
Current regulatory liabilities			
Cashout imbalance settlement[(1)]	$ 9	$ 8	N/A
Other	2	—	N/A
	11	8	
Non-current regulatory liabilities			
Environmental liability[(1)]	87	55	N/A
Cost of removal of offshore assets	51	51	N/A
Property and plant depreciation	28	22	Various
Plant regulatory liability[(1)]	11	12	N/A
Postretirement benefits[(1)]	11	9	N/A
Excess deferred income taxes	10	14	1-7
Other	5	—	N/A
Total non-current regulatory liabilities	203	163	
Total regulatory liabilities	$214	$171	

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

18. 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:

	2003	2002
	(In millions)	
Other current assets		
Prepaid assets	$ 153	$ 110
Other	65	83
Total	$ 218	$ 193
Other non-current assets		
Pension assets (see Note 23)	$ 962	$ 866
Notes receivable from affiliates	349	466
Restricted cash (see Note 2)	349	212
Unamortized debt expenses	246	180
Regulatory assets (see Note 17)	143	129
Long-term receivables	108	50
Notes receivable	113	48
Turbine inventory (see Note 16)	98	222
Other investments	60	108
Other	163	185
Total	$2,591	$2,466
Other current liabilities		
Accrued taxes, other than income	$ 156	$ 155
Broker margin and other amounts on deposit with us	155	123
Income taxes	132	23
Environmental, legal and rate reserves (see Note 22)	96	138
Deposits	67	66
Obligations under swap agreement	49	42
Other postretirement benefits (see Note 23)	45	35
Dividends payable	23	130
Other	187	188
Total	$ 910	$ 900
Other non-current liabilities		
Environmental and legal reserves (see Note 22)	$ 450	$ 409
Other postretirement and employment benefits (see Note 23)	272	322
Obligations under swap agreement	208	255
Regulatory liabilities (see Note 17)	203	163
Asset retirement obligations (see Note 2)	195	—
Other deferred credits	157	214
Accrued lease obligations	106	124
Insurance reserves	136	104
Deferred gain on sale of assets to GulfTerra (see Note 28)	101	268
Deferred compensation	60	46
Pipeline integrity liability (see Note 28)	69	—
Other	90	79
Total	$2,047	$1,984

19. Property, Plant and Equipment

At December 31, 2003 and 2002, we had approximately $1.1 billion and $1.4 billion of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2003 and 2002, 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 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, 2003, 2002, and 2001 was approximately $74 million, $71 million and $58 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.

20. Debt, Other Financing Obligations and Other Credit Facilities

	2003	2002
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,457	$ 2,075
Notes payable to affiliates	—	390
Long-term financing obligations	20,275	16,106
Total	$21,732	$18,571

Our debt and other credit facilities consist of both short and long-term borrowings with third parties and notes with our affiliated companies. During 2003, we entered into a new $3 billion revolving credit facility, acquired and consolidated a number of entities with existing debt, refinanced shorter-term obligations with longer-term borrowings and redeemed and eliminated preferred interests in our subsidiaries. A summary of our actions is as follows (in millions):

Debt obligations as of December 31, 2002	$18,571
Principal amounts borrowed(1)	4,250
Repayment of principal(1)	(3,982)
Other changes in debt:	
Clydesdale restructuring (Note 21)	743
Gemstone and Chaparral acquisition(2)	2,578
Consolidation of debt on Lakeside Technology Center lease (Note 3)	275
Reclassifications of preferred interests as long-term financing obligations(3)	625
Sale of entities(4)	(710)
Exchange of equity security units (Note 24)	(303)
Elimination of affiliate obligations	(326)
Other	11
Total debt as of December 31, 2003	$21,732

(1) Includes $500 million of borrowings and $1,150 million of repayments under our $3 billion revolving credit facility.

(2) These amounts were consolidated as a consequence of our acquisition of Chaparral and Gemstone as further discussed in Note 3. Of this amount, approximately $1,640 million is non-recourse project financing or contract debt.

(3) Relates to our adoption of SFAS No. 150. See Note 2.

(4) Includes $571 million in debt related to the sale of East Coast Power and $139 million related to the sale of Mohawk River Funding I.

Short-Term Financing Obligations

We had the following short-term borrowings and other financing obligations as of December 31:

	2003	2002
	(In millions)	
Current maturities of long-term debt and other financing obligations	$1,401	$ 575
Short-term financing obligation	56	—
Short-term credit facilities[1]	—	1,500
	$1,457	$2,075

[1] Our weighted-average interest rate on our short-term credit facilities was 2.69% at December 31, 2002.

Long-Term Financing Obligations

Our long-term financing obligations outstanding consisted of the following as of December 31:

	2003	2002
	(In millions)	
Long-term debt		
ANR Pipeline		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	$ 800	$ 500
Notes, 13.75% due 2010	13	13
Colorado Interstate Gas		
Debentures, 6.85% through 10.0%, due 2005 and 2037	280	280
El Paso CGP		
Senior notes, 6.2% through 8.125%, due 2004 through 2010	1,305	1,305
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,395	1,497
Other	—	440
El Paso Corporation		
Senior notes, 5.75% through 7.125%, due 2006 through 2009	1,817	1,597
Equity security units, 6.14% due 2007	272	575
Notes, 6.625% through 7.875%, due 2005 through 2018	2,002	2,021
Medium-term notes, 6.95% through 9.25%, due 2004 through 2032	2,812	2,812
Zero coupon convertible debentures due 2021	895	848
$3 billion revolver, LIBOR plus 3.5% due June 2005	850	—
El Paso Natural Gas		
Notes and senior notes, 7.625% through 8.375%, due 2010 through 2032	655	500
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	—
Power		
Non-recourse senior notes, 7.75% through 12%, due 2008 and 2017	770	86
Non-recourse notes, variable rates, due 2007 and 2008	361	—
Recourse notes, 7.27% and 8.5%, due 2007 and 2008	85	126
Gemstone notes, 7.71% due 2004	950	—
UCF, 7.944%, due 2016	829	829
Southern Natural Gas		
Notes and senior notes, 6.125% through 8.875%, due 2007 through 2032	1,200	800

	2003	2002
	(In millions)	
Tennessee Gas Pipeline		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
Notes, 8.375%, due 2032	240	240
Other	356	396
	20,933	16,711
Other financing obligations		
Capital Trust I	325	—
Coastal Finance I	300	—
Lakeside Technology Center lease financing loan due 2006	275	—
Other	—	17
	900	17
Subtotal	21,833	16,728
Less:		
Unamortized discount and premium on long-term debt	157	47
Current maturities	1,401	575
Total long-term financing obligations, less current maturities	$20,275	$16,106

During 2003 and to date in 2004, we had the following changes in our debt financing obligations:

Company	Type	Interest Rate	Principal	Net Proceeds/ Repayments in Debt	Due Date
			(In millions)		
Issuances[(1)(2)]					
ANR	Senior notes	8.875%	$ 300	$ 288	2010
El Paso[(3)]	Two-year term loan	LIBOR + 4.25%	1,200	1,149	2004-2005
El Paso Production Holding[(3)]	Senior notes	7.75%	1,200	1,169	2013
EPNG	Senior notes	7.625%	355	347	2010
Macae[(4)]	Notes	Various	95	95	2008
Macae[(4)]	Term loan	6.61%	200	200	2007
SNG	Senior notes	8.875%	400	385	2010
Issuances through December 31, 2003			3,750	3,633	
Macae	Term loan	LIBOR + 4.25%	50	50	2007
			$3,800	$3,683	
Repayments[(2)]					
Clydesdale	Term loan	Variable	$ 743	$ 743	
El Paso[(3)]	Two-year term loan	LIBOR + 4.25%	1,200	1,191	
El Paso CGP	Long-term debt	4.49%	240	240	
El Paso CGP	Note	Floating rate	200	200	
El Paso CGP	Senior debentures	9.75%	102	102	
EPNG	Note	6.75%	200	200	
Various	Long-term debt	Various	148	148	
Retirements through December 31, 2003			2,833	2,824	
El Paso CGP	Note	Libor + 3.5%	200	200	
El Paso CGP	Note	6.20%	190	190	
Gemstone	Notes	7.71%	202	202	
Other	Long-term debt	Various	268	268	
			$3,693	$3,684	

Company	Type	Interest Rate	Principal	Net Change in Debt	Due Date
			(In millions)		
Other Changes in Debt[5]					
Capital Trust I	Preferred securities	4.75%	$ 325	$ 325	2028
Chaparral[4]	Notes and loans	Various	1,671	1,565	Various
Clydesdale	Term loan	Various	743	743	2005
Coastal Finance I	Preferred securities	8.375%	300	300	2038
Gemstone	Notes	7.71%	950	938	2004
Lakeside Technology Center	Term loan	LIBOR + 3.5%	275	275	2006
Macae[4]	Term loan	Various	75	75	2007
East Coast Power[5]	Senior secured note	Various	(571)	(571)	
El Paso[6]	Equity security units	6.14%	(303)	(303)	
Mohawk River Funding I	Note	7.09%	(139)	(139)	
Other changes through December 31, 2003			3,326	3,208	
Blue Lake Gas Storage	Term Loan	LIBOR + 1.2%	14	14	2006
Mohawk River Funding IV[5]	Note	7.75%	(72)	(72)	
El Paso Power[5]	Non-recourse senior notes	7.944%	(815)	(815)	2016
			$2,453	$2,335	

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for other general corporate and investment purposes.

(2) Amount excludes $500 million of borrowings, $1,150 million of repayments in 2003 under our $3 billion revolving credit facility, which is classified as long-term debt, and $250 million of repayments in January 2004, which was classified as long-term debt.

(3) In conjunction with the redemption of our Trinity River financing (see Note 21), we obtained a $1.2 billion two year term loan based on LIBOR. This term loan was subsequently refinanced with the proceeds from our El Paso Production Holding senior note issuance.

(4) These amounts were consolidated as a consequence of our acquisition of Chaparral and Gemstone as further discussed in Note 3. The Chaparral and Macae debt obligations are non-recourse debt financings.

(5) In order to simplify our balance sheet and improve liquidity, we acquired, consolidated, or divested of various entities with debt obligations, among other actions which affected our debt balance. For a further discussion of these changes, see Notes 3, 4, 21, and 28.

(6) This debt related to the exchange of our equity security units to common stock.

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):

2004	$ 1,409
2005	1,585
2006	1,769
2007	981
2008	776
Thereafter	15,313
Total long-term financing obligations, including current maturities	$21,833

Included in the "thereafter" line of the table above are $895 million of zero coupon convertible debentures. These debentures have a maturity value of $1.8 billion, are due 2021 and have a yield to maturity of 4%. The holders can cause us to repurchase these at their option in years 2006, 2011 and 2016, at which time we can elect to settle in cash or common stock. These debentures are convertible into 8,456,589 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.

Also included in the "thereafter" line are $675 million of other debentures that holders have an option to redeem prior to their stated maturity. Of the total amount, $75 million can be redeemed in 2005 and $600 million can be redeemed in 2007.

Credit Facilities

In April 2003, we entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. This $3 billion revolving credit facility has a borrowing cost of LIBOR plus 350 basis points, letter of credit fees of 350 basis points and commitment fees of 75 basis points on the unused amounts of the facility. This $3 billion revolving credit facility replaced our previous $3 billion revolving credit facility. We also had a $1 billion revolving credit facility that matured in August 2003. Other financing arrangements (including the leases discussed in Notes 3 and 12, letters of credit and other facilities) were also amended to conform the provisions of those obligations to the new facility. The $3 billion revolving credit facility and those other financing arrangements are collateralized by our ownership in EPNG, TGP, ANR, CIG, WIC, ANR Storage Company, Southern Gas Storage Company and our Series A common units and Series C units in GulfTerra. The combined book value of this collateral was approximately $8.2 billion as of December 31, 2003. The total potential exposure under the financing transactions these assets collateralize was $3.3 billion as of September 15, 2004. As of December 31, 2003, there were $850 million of borrowings outstanding and $1.2 billion of letters of credit issued under the $3 billion revolving credit facility. Amounts outstanding under the $3 billion revolving credit facility as of December 31, 2003, are classified as non-current in our balance sheet, based on the facility's maturity date which is June 30, 2005. In January 2004, we repaid $250 million of the outstanding debt on the $3 billion revolving credit facility. As of September 15, 2004, our borrowing availability under this facility was $1.2 billion.

The availability of borrowings under our $3 billion revolving credit facility and other borrowing agreements is subject to various conditions as described beginning on page [150.] 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.

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% 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% 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%, 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 (see Note 21).

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% 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 (see Note 21).

Equity Security Units

In June 2002, we issued 11.5 million, 9% 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% 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%. 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. For each unit tendered, the holder received 2.5063 shares of common stock and cash in the amount of $9.70 per equity security unit. 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. Upon completion of the tender offer and comparison of the fair value of financial instruments exchanged to their respective book values, we recorded (i) a net loss of $12 million in other income in our income statement associated with the debt component of the equity security units; (ii) $45 million in common stock and $189 million in additional paid-in-capital associated with the equity component of the units; and (iii) $22 million of other asset and liability changes associated with the exchange.

When the remaining purchase contracts are settled in 2005, we will 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. At the time the security units were issued, we recorded approximately $43 million of other non-current liabilities to reflect the present value of the quarterly contract adjustment payments that we are making on these units with an offsetting reduction in additional paid-in capital. As of December 31, 2003, the remaining amount of this liability was $10 million. The quarterly contract adjustment payments are allocated between the liability recognized at the date of issuance and interest expense based on a constant rate over the term of the purchase contracts. Accretion of the quarterly contract adjustment payments is recorded as interest expense.

Restrictive Covenants

We and our subsidiaries have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross-payment default and cross-acceleration 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 $3 billion revolving credit facility, the significant debt covenants and cross defaults are:

(a) the ratio of consolidated debt and guarantees to capitalization (as defined in the $3 billion revolving credit facility) cannot exceed 75 percent. For purpose of this calculation, we are allowed to add back to capitalization non-cash impairments of long-lived assets, including ceiling test charges, and exclude the impact of accumulated other comprehensive income (loss), among other items. Additionally, in determining debt under these agreements, we are allowed to exclude certain non-recourse project finance debt, among other items;

(b) EPNG, TGP, ANR, and CIG, our subsidiaries, cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in the new $3 billion revolving credit facility agreement) for that particular company to exceed 5 to 1. Additionally, the proceeds from the issuance of debt by the 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

(c) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to debt (other than excluded items) in an aggregate principal amount of $200 million or more.

In addition to the above restrictions, 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 borrowings at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the incurrence 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.

As discussed in Note 1 above, we restated our historical financial statements to reflect a reduction in our historically reported proved natural gas and oil reserves and to revise the manner in which we accounted for certain hedges, primarily associated with our anticipated natural gas production.

We believe that a material restatement of our financial statements would have constituted events of default under our $3 billion revolving credit facility and various other financing transactions; specifically under the provisions of these arrangements related to representations and warranties on the accuracy of our historical financial statements and on our debt to total capitalization ratio. During 2004, we received several waivers on our $3 billion revolving credit facility and various other financing transactions to address these issues. These waivers continue to be effective. We also received an extension with various lenders until November 30, 2004 to file our first and second quarter 2004 Forms 10-Q, which we expect to meet. If we are unable to file these Forms 10-Q by that date and are not able to negotiate an additional extension of the filing deadline, our $3 billion revolving credit facility and various other transactions could be accelerated. As part of obtaining these waivers, we also amended various provisions of the $3 billion revolving credit facility, including provisions related to events of default and limitation, on our ability as well as that of our subsidiaries, to repay indebtedness scheduled to mature after June 30, 2005. Based upon a review of the covenants contained in our indentures and the financing agreements of our other outstanding indebtedness, the acceleration of our $3 billion revolving credit facility could constitute an event of default under some of our other debt agreements. In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

Various other financing arrangements entered into by us and our subsidiaries, including El Paso CGP and El Paso Production Holding Company, include covenants that require us to file financial statements within specified time periods. Non-compliance with such covenants does not constitute an automatic event of default. Instead, such agreements are subject to acceleration when the indenture trustee or the holders of at least 25 percent of the outstanding principal amount of any series of debt provides notice to the issuer of non-compliance under the indentures. In that event, the non-compliance can be cured by filing financial statements within specified periods of time (between 30 and 90 days after receipt of notice depending on the particular indenture) to avoid acceleration of repayment. The holders of El Paso Production Holding Company's debt obligations waived the financial filing requirements through December 31, 2004. The filing of our first and second quarter 2004 Forms 10-Q for these subsidiaries will cure the events of non-compliance resulting from our failure to file financial statements on these subsidiaries. In addition, neither we nor any of our subsidiaries have received a notice of the default caused by our failure to file our financial statements or the financial statements of our subsidiaries also impacted by the restatements. In the event of an acceleration, we may be unable to meet our payment obligations with respect to the related indebtedness.

We have also issued various guarantees securing financial obligations of our subsidiaries and unconsolidated affiliates with similar covenants as in the above facilities.

Furthermore, a material restatement of our financial statements for the period ended December 31, 2001 could cause a default under the financing agreements entered into in connection with our $950 million Gemstone notes due October 31, 2004. Currently, $748 million of Gemstone notes are outstanding. However, we currently expect to repay these notes in full upon their maturity on October 31, 2004.

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. El Paso CGP's net worth at December 31, 2003, was approximately $3.3 billion.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million of 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.

Available Capacity Under Shelf Registration Statements

We maintain a shelf registration statement with the SEC that allows us to issue up to $3 billion in securities. Under this registration statement, we can 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 will be required to issue full and unconditional guarantees on these securities. As of December 31, 2003, we had $999 million remaining capacity under this shelf registration statement. However, in order to access this capacity, we will be required to increase the level of disclosure in our shelf registration statement due to the non-timely filing of our annual financial statements. This increased disclosure could be subject to review by the Securities and Exchange Commission which could result in delays in accessing this capacity.

Letters of Credit

We enter into letters of credit in the ordinary course of our operating activities. As of December 31, 2003, we had outstanding letters of credit of approximately $1.4 billion versus $869 million as of December 31, 2002. Of the $1.4 billion outstanding letters of credit, approximately $1.2 billion was outstanding under our $3 billion revolving credit facility. Included in this amount were $0.6 billion of letters of credit securing our recorded obligations related to price risk management activities and $0.2 billion of letters of credit associated with our Eagle Point and Aruba refineries that were sold in 2004. Of the outstanding letters of credit, $65 million was supported with cash collateral.

Notes Payable to Affiliates

At December 31, 2002, our notes payable to affiliates was $390 million, which included $248 million of Chaparral debt securities and $123 million of Gemstone debt securities. We consolidated and/or retired all of these securities during 2003.

21. 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. Total amounts outstanding under these programs at December 31 were as follows (in millions):

	2003	2002
Consolidated trusts	$ —	$ 625
Trinity River	—	980
Clydesdale	—	950
Preferred stock of subsidiaries	300	400
Gemstone	—	300
	$300	$3,255

Summarized below are our actions during 2003 related to our preferred interests of consolidated subsidiaries (in millions):

Balance as of December 31, 2002	$3,255
Redemption of Trinity River	(980)
Refinancing and redemptions of Clydesdale	(950)
Elimination of Gemstone preferred interest	(300)
Redemption of Coastal Securities preferred stock	(100)
Reclassification of Capital Trust I and Coastal Finance I[1]	(625)
Balance as of December 31, 2003	$ 300

[1] These amounts were reclassified to long-term financing obligations as a result of our adoption of SFAS No. 150. See Note 20.

Trinity River. In 1999, we entered into the Trinity River financing arrangement to generate funds for investment and general operating purposes. As of December 31, 2002, approximately $980 million was outstanding under this arrangement. In the first quarter of 2003, we redeemed the entire $980 million of the outstanding preferred interests under the arrangement with a portion of the proceeds from the issuance of a $1.2 billion two-year term loan (see Note 20).

Clydesdale. In 2000, we entered into the Clydesdale financing arrangement to generate funds for investment and general operating purposes. As of December 31, 2002, approximately $950 million was outstanding under this arrangement. Prior to April 2003, we retired approximately $197 million of the third party member interests in Clydesdale. In April 2003, we restructured the Clydesdale arrangement whereby the remaining unredeemed preferred member interests of $753 million were converted to a term loan. The term loan was being amortized in equal quarterly amounts of $100 million through 2005. We also purchased $10 million of preferred equity of the third party investor in Clydesdale, Mustang Investors, L.L.C., which along with a financial guarantee of repayment by us, resulted in the consolidation of Mustang in the second quarter of 2003. This consolidation resulted in an increase in our long-term debt of approximately $743 million and a reduction in our preferred interests of consolidated subsidiaries of approximately $753 million. In December 2003, we repaid the remaining amount outstanding on the Clydesdale term loan.

Gemstone. As of December 31, 2002, Gemstone owned $300 million in preferred securities in two of our consolidated subsidiaries. In the second quarter of 2003, we acquired a 100 percent interest in the holder of these preferred interests and began consolidating this equity holder. As a result of this consolidation, we eliminated this preferred interest (see Note 3).

Coastal Securities Company Preferred Stock. In 1996, Coastal Securities Company Limited, our wholly owned subsidiary, issued 4 million shares of preferred stock for $100 million to Cannon Investors Trust, which is an entity comprised of a consortium of banks, to generate funds for investment and general operating purposes. In December 2003, we redeemed the entire $100 million of the outstanding preferred interests and paid the accrued and unpaid dividends.

El Paso Tennessee Preferred Stock. In 1996, El Paso Tennessee Pipeline Co., our subsidiary, issued 6 million shares of publicly registered 8.25% 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. El Paso Tennessee Pipeline Co. indirectly owns Tennessee Gas Pipeline Company, our marketing and trading businesses and substantially all of our domestic and international power businesses. While not required, the following financial information is intended to provide additional information on El Paso Tennessee Pipeline Co. to its preferred security holders:

	Year Ended December 31,		
	2003	2002	2001
	(In millions)		
Operating results data:			
Operating revenues	$1,459	$ 1,132	$3,593
Operating expenses	1,865	2,268	2,559
Income (loss) from continuing operations	(377)	(1,300)	669
Net income (loss)	(377)	(1,425)	717

	December 31,	
	2003	2002
	(In millions)	
Financial position data:		
Current assets	$4,217	$ 6,909
Non-current assets	9,976	10,173
Short-term debt	1,063	2
Other current liabilities	5,457	8,441
Long-term debt	2,545	1,721
Other non-current liabilities	2,642	3,604
Securities of subsidiaries	28	355
Equity in net assets	2,458	2,959

22. Commitments and Contingencies

Legal Proceedings and Government Investigations

Western Energy Settlement. In June 2003, we announced that we had executed a Master Settlement Agreement or MSA to resolve the principal litigation relating to the sale or delivery of natural gas and/or electricity to or in the Western United States. The MSA became effective in June 2004. The MSA, along with separate settlement agreements, settled California lawsuits in the state courts, the California Public Utilities Commission (CPUC) proceeding at the FERC, and the California Attorney General investigation discussed herein. Parties to the settlement agreements include private class action litigants in California; the governor and lieutenant governor of California; the attorneys general of California, Washington, Oregon and Nevada; the CPUC; the California Electricity Oversight Board; the California Department of Water Resources; Pacific Gas and Electric Company (PG&E), Southern California Edison Company, five California municipalities and six non-class private plaintiffs. For a discussion of the charges taken in connection with the Western Energy Settlement as well as amounts released to the settling parties and our remaining obligations under the settlement, see Note 6.

In the MSA, we agreed to the following terms:

- We made cash payments totaling $95.5 million for the benefit of the parties to the definitive settlement agreements subsequent to the signing of these agreements. This amount represents the originally announced $102 million cash payment less credits for amounts that have been paid to other settling parties;
- We paid amounts equal to the proceeds from the issuance of approximately 26.4 million shares of our common stock on behalf of the settling parties. The proceeds from such sales in 2003 and 2004 totalling approximately $195 million were deposited into an escrow account for the benefit of the settling parties;
- We deposited approximately $250 million in escrow for the benefit of the settling parties within 180 days of the signing of the definitive settlement agreements;
- We will pay $45 million in cash per year in semi-annual payments over a 20-year period. This long-term payment obligation is a direct obligation of El Paso Corporation and El Paso Merchant Energy, L.P. (EPME) and will be guaranteed by our subsidiary, EPNG. We were required to provide

collateral for this obligation in the form of natural gas and oil reserves. We posted oil and gas collateral to collateralize these payment obligations in June 2004 upon the effectiveness of the MSA; and

- EPME agreed to receive reduced payments due under a power supply transaction with the California Department of Water Resources by a total of $125 million, pro rated on a monthly basis over the remaining 30 month term of the transaction. The difference between the current payments and the reduced payments prior to the effectiveness of the MSA was placed into escrow for the benefit of the settling parties on a monthly basis. Upon effectiveness, the actual payments to EPME for delivered power were made at the reduced amounts.

The MSA is in addition to the Joint Settlement Agreement or JSA announced earlier in June 2003 where we agreed to provide structural relief to the settling parties. In the JSA, we agreed to do the following:

- Subject to the conditions in the settlement; (1) make 3.29 Bcf/d of primary firm pipeline capacity on our EPNG system available to California delivery points during a five year period from the date of settlement, but only if shippers sign firm contracts for 3.29 Bcf/d of capacity with California delivery points; (2) maintain facilities sufficient to deliver 3.29 Bcf/d to the California delivery points; and (3) not add any firm incremental load to our EPNG system that would prevent it from satisfying its obligation to provide this capacity;
- Construct a new 320 MMcf/d, Line 2000 Power-Up expansion project and forego recovery of the cost of service of this expansion until EPNG's next rate case before the FERC;
- Clarify the rights of Northern California shippers to recall some of EPNG's system capacity (Block II capacity) to serve markets in PG&E's service area; and
- With limited exceptions, 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, in anticipation of the execution of the MSA, El Paso, the CPUC, PG&E, Southern California Edison Company, and the City of Los Angeles filed the JSA described above with the FERC in resolution of the CPUC complaint proceeding discussed below. 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.

We are a defendant in a number of additional lawsuits, pending in several Western states, relating to various aspects of the 2000-2001 Western energy crisis. We do not believe these additional lawsuits, either individually or in the aggregate, will have a material impact on us.

Shareholder Class Action Suits. Beginning in July 2002, twelve purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our former officers. Eleven of these lawsuits are now consolidated in federal court in Houston before a single judge. The twelfth lawsuit, filed in the Southern District of New York, was dismissed in light of similar claims being asserted in the consolidated suits in Houston. The lawsuits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. Two shareholder derivative actions have also been filed which generally allege the same claims as those made in the consolidated shareholder class action lawsuits. One, which was filed in federal court in Houston in August 2002, has been consolidated with the shareholder class actions pending in Houston, and has been stayed. The second shareholder derivative lawsuit, filed in Delaware State Court in October 2002, generally alleges the same claims as those made in the consolidated shareholder class action lawsuit and also has been stayed. Two other shareholder derivative lawsuits are now consolidated in state court in Houston. Both generally allege that manipulation of California gas supply and gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Beginning in February 2004, seventeen purported shareholder class action lawsuits alleging violations of federal securities laws were filed against us and several individuals in federal court in Houston. The lawsuits generally allege that our reporting of natural gas and oil reserves was materially false and misleading. Each of these lawsuits recently has been consolidated into the shareholder lawsuits described in the immediately preceding paragraph. An amended complaint in this consolidated securities lawsuit was filed on July 2, 2004.

In September 2004, a new derivative lawsuit was filed in federal court in Houston against certain of El Paso's current and former directors and officers. The claims in this new derivative lawsuit are for the most part the same claims made in the June 2004 consolidated amended complaint in the securities lawsuit. The one distinction is that the derivative lawsuit includes a claim for disgorgement under Sarbanes-Oxley Act of 2002 against certain of the individually named defendants.

ERISA Class Action Suit. In December 2002, a purported class action lawsuit was filed in federal court in Houston 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 recently was amended to include allegations relating to our reporting of natural gas and oil reserves. Our costs and legal exposure related to this lawsuit are not currently determinable; however, we believe this matter will be covered by insurance.

CPUC Complaint Proceeding Docket No. RP00-241-000. In April 2000, the CPUC filed a complaint under Section 5 of the Natural Gas Act (NGA) with FERC alleging that EPNG's sale of approximately 1.2 Bcf of capacity to its affiliate, EPME, raised issues of market power and was a violation of the FERC's marketing affiliate regulations and asked that the contracts be voided. In the spring and summer of 2001, hearings were held before an ALJ to address the market power issue and the affiliate issue. On November 19, 2003, the FERC approved the JSA, which is part of the Western Energy Settlement and vacated the ALJ's initial decisions. That decision was upheld by the FERC in an order issued on March 30, 2004. On April 9, 2004, certain shippers appealed both FERC orders on this matter to the U.S. Court of Appeals for the District of Columbia Circuit.

Governmental and Other Reviews. 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 are cooperating 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 are also cooperating with the U.S. Attorney regarding an investigation of specific transactions executed in connection with our production 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 between EPME and the CFTC of the price reporting matter providing for the payment by EPME of a civil monetary penalty 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 reserve revisions. We have also received federal grand jury subpoenas for documents with regard to the reserve revisions. We are cooperating with the SEC and the U.S. Attorney investigations into the matter.

CFTC Investigation. In April 2004, our affiliates elected to voluntarily cooperate with the CFTC in connection with the CFTC's industry-wide investigation of activities affecting the price of natural gas in the fall of 2003. Specifically, our affiliates provided information relating to storage reports provided to the Energy

Information Administration for the period of October 2003 through December 2003. On August 30, 2004, the CFTC announced they had completed the investigation and found no evidence of wrongdoing.

Iraq Oil Sales. In September 2004, the Coastal Corporation (now El Paso CGP Company) 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 Nation's 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. Others in the energy industry have received similar subpoenas.

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. On June 20, 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.

On November 1, 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. On April 2, 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 personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All of these lawsuits have been settled, with settlement payments fully covered by insurance. In connection with the settlement of the cases, EPNG contributed $10 million to a charitable foundation as a memorial to the families involved. The contribution was not covered by insurance.

Parties to four of the settled lawsuits have since filed an additional lawsuit titled *Diane Heady et al. v. EPEC and EPNG* in Harris County, Texas on November 20, 2002, seeking additional sums based upon their interpretation of earlier settlement agreements. An agreement in principle has been reached which will resolve all issues with these parties. In addition, a lawsuit entitled *Baldonado et. al. v. EPNG* was filed on June 30, 2003 in state court in Eddy County, New Mexico on behalf of 23 firemen and EMS personnel who responded to the fire and who allegedly have suffered psychological trauma. This case was dismissed by the trial court. The appeals court initially issued a notice dismissing all claims. This decision was appealed and the appeals court has agreed to hear this matter. Briefs will be filed by the end of this year. We believe that decision may be appealed. Our costs and legal exposure related to the *Baldonado* lawsuit are not currently determinable, however we believe this matter will be fully covered by insurance.

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). Discovery is proceeding. 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 on April 10, 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. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use 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 our subsidiaries are currently one of several defendants in over 50 such lawsuits nationwide, which have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs generally 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 and claims are not currently determinable.

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.

For each of our outstanding legal matters, we evaluate the merits of the case, 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, we establish the necessary accruals. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate. As of December 31, 2003, we had approximately $1.2 billion accrued for all outstanding legal matters, which includes the accruals related to 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, 2003, we had accrued approximately $412 million, including approximately $400 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $12 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $412 million accrual, $179 million was reserved for facilities we currently operate, and $233 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 $412 million to approximately $632 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 ($94 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($318 million to $538 million) and the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

Sites	December 31, 2003 Low	High
	(In millions)	
Operating	$179	$255
Non-operating	201	333
Superfund	32	44

Below is a reconciliation of our accrued liability as of December 31, 2003 (in millions):

Balance as of January 1, 2003	$389
Additions/adjustments for remediation activities	8
Payments for remediation activities	(52)
Other changes, net	67
Balance as of December 31, 2003	$412

For 2004, we estimate that our total remediation expenditures will be approximately $68 million. In addition, we expect to make capital expenditures for environmental matters of approximately $86 million in the aggregate for the years 2004 through 2008. 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. In May 2003 we finalized a new estimate of the cost to complete the PCB/HSL Project. Over the years there have been developments that impacted various individual components, but our ability to estimate a more likely outcome for the total project has not been possible until recently. The new estimate identified a $31 million reduction in our estimated cost to complete the project.

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, 2003, TGP had pre-collected PCB costs by approximately $119 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, 2003, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $87 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 62 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, 2003, we have estimated our share of the remediation costs at these sites to be between $32 million and $44 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 reserves are adequate.

Other

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. We sold $244 million of the original claims to a third party. Enron also maintained that El Paso Merchant Energy-Petroleum owed it approximately $3 million, and that EPME owed EPMI $46 million, each due to the termination of petroleum and physical power contracts. In both cases, we maintained that due to contractual setoff rights, no money was owed to the Enron parties. Additionally, EPME maintained that EPMI owed EPME $30 million due to the termination of the physical power contract, which is included in the $317 million of filed claims. EPMI filed a lawsuit against EPME and its guarantor, El Paso Corporation, based on the alleged $46 million liability. On June 24, 2004, the Bankruptcy Court approved a settlement agreement with Enron that resolved all of the foregoing issues as well as most other trading or merchant issues between the parties. Our European trading businesses also asserted $20 million in 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 exposure to Enron is $3 million.

In addition, various Enron subsidiaries had transportation contracts on several of our pipeline systems. Most of these transportation contracts have now been rejected, and our pipeline subsidiaries have 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. 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 the rejection date.

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 it 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.

Economic Conditions of Brazil. We own and have investments in power, pipeline and production assets in Brazil with an aggregate exposure, including financial guarantees, of approximately $1.6 billion. During 2002, Brazil experienced a significant decline in its financial markets due largely to concerns over the refinancing of its foreign debt and the presidential elections which were completed in late November 2002. These concerns contributed to significantly higher interest rates in 2002 on local debt for the government and private sectors, significantly decreased the availability of funds from lenders outside of Brazil and decreased the amount of foreign investment in the country. In addition, the government may impose or attempt to impose changes that could affect our investments, including imposing price controls on electricity and fuels, attempting to force renegotiation of power purchase agreements (PPA's) which provide for partial protection from local currency devaluation or attempting to impose other concessions. These developments have delayed and may continue to delay the implementation of project financings planned and underway in Brazil (although we have raised $420 million of non-recourse debt on our Macae power project through February 2004). We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our investment in the country, but we continue to monitor the economic situation and potential changes in governmental policy, and are working with the state-controlled utilities in Brazil that are counterparties under our projects' PPA's to attempt to maintain the economic returns we anticipated when we made our investments. Some of the specific difficulties we are experiencing in Brazil are discussed below.

We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The project company in which we have an ownership interest has a 20-year PPA with a regional utility that is currently in international arbitration and in litigation in Curitiba courts. 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 $181 million at December 31, 2003. Based on the future outcome of our dispute under the PPA, we could be required to write down the value of our investment.

We own two projects located in Manaus, Brazil. The first project is a 238 MW fuel-oil fired plant known as the Manaus Project, which has a net book value of $104 million at December 31, 2003 and the second project is a 158 MW fuel-oil fired plant known as the Rio Negro Project with a net book value of plant equipment of $108 million at December 31, 2003. The Manaus Project's PPA currently expires in January 2005 and the Rio Negro Project's PPA currently expires in January 2006. In the first quarter of 2003, the Manaus Project began experiencing delays in payment from the purchaser of our power, Manaus Energia S.A. In the fourth quarter of 2003, all of the contractual issues were resolved and a payment schedule was established and is being followed for all payments in arrears. These past due payments were collected as of March 2004. As of December 31, 2003, our accounts receivable on the Manaus Project is $19 million. In addition, we have filed a lawsuit in the Brazilian courts against Manaus Energia on the Rio Negro Project regarding a tariff dispute related to power sales from 1999 to 2003 and have an additional long-term receivable of $32 million which is a subject of this lawsuit. As a result of changes in the Brazilian political environment in early 2004, Manaus Energia issued a request for power supply proposals for 450 MW to 525 MW of net generating capacity from 2005 to 2006. The bid qualifications issued by Manaus Energia may prohibit us from supplying power from our Manaus and Rio Negro projects. We have filed both administrative and legal challenges to these bid qualifications and intend to submit a bid. A non-governmental organization has obtained a preliminary injunction enjoining Manaus Energia from proceeding with the bid process until a decision on the merits of their complaint is made. Based on the expected results of the bid process and its impact on the future outcome of any negotiations to extend the term of the PPA's, we recorded an impairment charge of approximately $135 million in the first quarter of 2004. Based on the future outcome of the lawsuit related to the $32 million receivable, we could be required to provide an allowance for the receivable discussed above.

We own a 50 percent interest in a 404 MW dual-fuel-fired power project known as the Porto Velho Project, located in Porto Velho, Brazil. The Porto Velho Project has two PPA's. The first PPA has a term of ten years and relates to the first phase of the project. The second PPA has a term of 20 years and relates to the second 345 MW phase of the project. We are negotiating certain provisions of both PPA's with EletroNorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. Although the current terms of the PPA's and the proposed amendments do not indicate an impairment of our investment, which was $283 million at December 31, 2003, we may be required to write down the value of our investment if these negotiations are resolved unfavorably.

While the outcome of these matters cannot be predicted with certainty 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. The impact of these changes may have a material effect on our results of operations, our financial position, and our cash flows in the periods these events occur.

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 2004 until 2053. As of December 31, 2003, our total commitments under operating leases were approximately $488 million. Minimum annual rental commitments under our operating leases at December 31, 2003, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2004	$ 72
2005	69
2006	66
2007	52
2008	44
Thereafter	185
Total	$488

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $16 million due in the future under noncancelable subleases. Rental expense on our operating leases for the years ended December 31, 2003, 2002 and 2001 was $72 million, $146 million, and $94 million.

In May 2004, we announced we would consolidate our Houston-based operations into one location. We anticipate the consolidation will be substantially complete by the end of 2004. As a result, we have established or will establish an accrual to record a liability for our obligations under the terms of the leases in the period that the space is vacated and available for subleasing. We currently lease approximately 912,000 square feet of office space in the buildings we are vacating under various leases with lease terms expiring in 2004 through 2014. We estimate the total accrual for the space will be approximately $80 million to $100 million. Expenses related to the relocation will be expensed in the period that they are incurred.

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. As of December 31, 2003, we had approximately $277 million of financial and performance guarantees not otherwise reflected in our financial statements.

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. In these cases, we evaluate at the time the guaranty 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, 2003, we had accrued $78 million related to these arrangements.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2003, we had firm commitments under tolling, transportation and storage capacity contracts of $1.8 billion, commodity purchase commitments of $361 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $429 million. Included in other purchase and capital commitments is our purchase obligation, entered into during 2003, to acquire pipe and other equipment to be used in our Cheyenne Plains Pipeline project totaling $136 million, which will be paid during 2004.

23. 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 2004.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides 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 employees who are union members. Our contributions to this plan during 2003, 2002 and 2001 were not material. We expect to contribute $6 million to the SERP in 2004. We do not anticipate making any contributions to our other pension plans in 2004.

In 2001, we offered an early retirement incentive program associated with our pension plans for eligible employees of Coastal. This program offered enhanced pension benefits to individuals who elected early retirement. Net charges incurred in connection with this program were approximately $137 million in 2001. During 2003, we had $11 million in charges in our primary pension plan 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 contribution 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 contribution, 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 contribution to 75 percent of participant basic contributions up to 6 percent. As a result of El Paso not being current on its SEC filings, the Plan Committee temporarily suspended participants from making future contributions to or transferring other investment funds to the El Paso Corporation Stock Fund effective June 25, 2004. This temporary suspension does not affect the participant's ability to maintain or transfer the investment that they may currently have in the El Paso Corporation Stock Fund. Participants may continue to sell stock currently held in the El Paso Corporation Stock Fund at their discretion (subject to any insider trading restrictions). As soon as El Paso completes its required SEC filings and is in compliance with the SEC requirements, participants will be able to invest in the

El Paso Corporation Stock Fund again. Amounts expensed under this plan were approximately $14 million, $28 million and $30 million for the years ended December 31, 2003, 2002 and 2001.

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) 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 $59 million to these postretirement plans in 2004. 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. In 2001, we offered a one-time election to continue benefits in our postretirement medical and life plans through an early retirement incentive program for eligible employees of Coastal. Net charges incurred with the Coastal program were approximately $65 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. Benefit obligations and costs reported that are related to prescription drug coverage do not reflect the impact of this legislation. Current accounting standards that are effective in 2004 may require changes to previously reported benefit information.

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	
	2003	2002	2003	2002
	(In millions)			
Projected benefit obligation	$1,928	$1,911	$163	$177
Accumulated benefit obligation	1,902	1,857	163	167
Fair value of plan assets	2,104	1,984	93	87
Accrued benefit liability	—	—	69	75
Prepaid benefit cost	960	898	21	—
Accumulated other comprehensive loss	—	—	37	55

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

	2003	2002
	(In millions)	
Projected benefit obligation	$134	$177
Accumulated benefit obligation	134	167
Fair value of plan assets	63	87

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 $18 million in 2003 and $(55) million in 2002 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	
	2003	2002	2003	2002
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	$2,088	$1,966	$ 558	$ 560
Service cost	36	33	1	1
Interest cost	134	135	35	38
Participant contributions	—	—	24	20
Settlements, curtailments and special termination benefits	—	—	(6)	—
Actuarial loss	22	129	50	17
Benefits paid	(189)	(175)	(87)	(78)
Projected benefit obligation at end of period	$2,091	$2,088	$ 575	$ 558
Change in plan assets:				
Fair value of plan assets at beginning of period	$2,072	$2,479	$ 164	$ 168
Actual return (loss) on plan assets	285	(246)	25	(14)
Employer contributions	29	14	70	68
Participant contributions	—	—	24	20
Benefits paid	(189)	(175)	(87)	(78)
Fair value of plan assets at end of period	$2,197	$2,072	$ 196	$ 164
Reconciliation of funded status:				
Fair value of plan assets at September 30	$2,197	$2,072	$ 196	$ 164
Less: Projected benefit obligation at end of period	2,091	2,088	575	558
Funded status at September 30	106	(16)	(379)	(394)
Fourth quarter contributions and income	2	4	17	17
Unrecognized net actuarial loss[1]	868	921	57	25
Unrecognized net transition obligation	1	(1)	15	23
Unrecognized prior service cost	(28)	(30)	(7)	(8)
Prepaid (accrued) benefit cost at December 31,	$ 949	$ 878	$(297)	$(337)

(1) Our unrecognized net actuarial loss as of September 30, 2003, and for the year ended December 31, 2003, was primarily the result of a decrease in the discount rate used in the actuarial calculation and lower actual returns on plan assets compared to our expected return during 2002. We recognize the difference between the actual return and our expected return over a three year period as permitted by SFAS No. 87.

The portion of our other postretirement benefit obligation included in current liabilities was $45 million and $35 million as of December 31, 2003 and 2002. For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
	(In millions)					
Service cost	$ 36	$ 33	$ 35	$ 1	$ 2	$ 1
Interest cost	134	135	134	35	38	42
Expected return on plan assets	(227)	(260)	(311)	(9)	(9)	(10)
Amortization of net actuarial (gain) loss	7	—	(41)	1	(1)	(2)
Amortization of transition obligation	(1)	(6)	(6)	8	8	8
Amortization of prior service cost(1)	(3)	(3)	(2)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	11	—	137	(6)	—	65
Net benefit cost (income)	$ (43)	$(101)	$ (54)	$29	$ 37	$103

(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 cost of our pension and other postretirement plans for 2003, 2002 and 2001:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	2003	2002	2001
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	6.00	6.75		6.00	6.75	
Rate of compensation increase	4.00	4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.75	7.25	7.75	6.75	7.25	7.75
Expected return on plan assets(1)	8.80	8.80	10.00	7.50	7.50	7.50
Rate of compensation increase	4.00	4.00	4.50			

(1) The expected return on plan assets is a pre-tax rate (before a tax rate of 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 2004, the assumed expected return on assets for pension benefits will be reduced to 8.50%.

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 2003, gradually decreasing to 5.5 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

	2003	2002
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	21	20
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(19)	(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 2003	Actual 2002	Target	Actual 2003	Actual 2002
		(Percent)			(Percent)	
Equity securities[1]	70	70	66	65	29	32
Debt securities	30	29	33	35	60	9
Other	—	1	1	—	11	59
Total	100	100	100	100	100	100

(1) Actuals for our pension plans include $33 million (1.5 percent of total assets) and $39 million (1.8 percent of total assets) of our common stock at September 30, 2003 and September 30, 2002.

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 late 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, 2003 had not yet been adjusted to reflect this allocation change. For 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 2004 assumption related to the expected return on plan assets will be reduced from 8.80% to 8.50% to reflect this change.

24. Capital Stock

Common Stock

In November and December 2003, we issued 17.6 million shares of common stock for approximately $121 million in partial satisfaction of our Western Energy Settlement obligation. In January 2004, we issued 8.8 million shares of common stock for $74 million to satisfy the remaining stock obligation under that settlement.

We also issued approximately 15 million shares as part of an offer to exchange our equity security units in December 2003 for common stock (for a further discussion, see Note 20).

Dividend

For the year ended December 31, 2003, we paid dividends of $203 million to common stockholders. To date in 2004, we have paid dividends of $74 million on our common stock. On July 16, 2004, we declared quarterly dividends of $0.04 per share on our common stock, payable on October 4, 2004, to the shareholders of record as of September 3, 2004.

El Paso Tennessee Pipeline Co., our subsidiary, paid dividends in 2003 of approximately $25 million on its Series A cumulative preferred stock, which is 8.25% per annum (2.0625% per quarter). To date in 2004, EPTP has paid dividends of approximately $12 million and declared its quarterly dividend on September 7, 2004 payable on September 30, 2004.

25. 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, 2003, approximately 29 million shares remained unissued.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2003, 2002 and 2001. 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. We also granted options to non-employee members of the Board of Directors at fair market value on the grant date that are exercisable immediately except in special circumstances. A summary of our stock option transactions, stock options outstanding and stock options exercisable as of December 31 is presented below:

	Stock Options					
	2003		2002		2001	
	# 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	43,208,374	$49.16	44,822,146	$50.02	19,664,151	$34.43
Granted	1,180,041	$ 7.29	3,435,138	$35.41	28,327,468	$60.19
Exercised	—	—	(310,611)	$22.44	(1,396,409)	$25.88
Converted[1]	(871,250)	$42.09	—	—	—	—
Forfeited	(7,272,151)	$49.53	(4,738,299)	$51.83	(1,773,064)	$58.00
Outstanding at end of year	36,245,014	$47.90	43,208,374	$49.18	44,822,146	$50.02
Exercisable at end of year	28,703,151	$46.04	25,493,152	$43.00	14,357,245	$33.58
Weighted average fair value of options granted during the year		$ 3.21		$14.23		$15.75

(1) Includes the conversion into common stock and cash of stock options at no cost to employees based upon achievement of certain performance targets and lapse of time. These options had an original stated exercise of approximately $42 per share.

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, 2003.

	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	3,744,685	4.2	$13.48	2,515,892	$15.73
$21.40 - $42.89	11,284,049	4.1	$37.49	10,749,337	$37.34
$42.90 - $64.29	15,252,532	5.4	$55.18	12,969,271	$54.48
$64.30 - $70.63	5,963,748	6.6	$70.58	2,468,651	$70.53
	36,245,014	5.1	$47.90	28,703,151	$46.04

The fair value of each stock option granted used to complete pro forma net income disclosures (see Note 2) is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption:	2003	2002	2001
Expected Term in Years	6.19	6.95	7.25
Expected Volatility	52.1%	43.4%	26.6%
Expected Dividends	2.2%	1.8%	3.0%
Risk-Free Interest Rate	3.4%	3.2%	4.7%

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 0.4 million, 1.4 million, and 2.3 million shares were granted during 2003, 2002 and 2001 with a weighted-average grant date fair value of $7.46, $38.45 and $62.10 per share. At December 31, 2003, 2.3 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 period of service. For 2003, 2002 and 2001, these charges totaled $64 million, $73 million and $67 million. Included in deferred compensation at December 31, 2003 is $23 million related to options that will be converted automatically into common stock at the end of their vesting period.

Performance Units

In the past, we awarded eligible officers performance units that are payable in cash or stock at the end of the vesting period. The final value of the performance units may vary according to the plan under which they are granted, but is 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 is 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. Amounts recorded to compensation expense in 2002 and 2001 were ($11) million and $64 million. Our 2001 expense includes a $51 million charge to pay out all of our outstanding phantom stock options. In 2002 we reduced 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 years ended December 31, 2002 and 2001, we sold 1.4 million, and 0.3 million shares of our common stock to our employees. Effective January 1, 2003, we suspended our employee stock purchase program.

26. Segment Information

We segregate our business activities into four operating segments: Pipelines, Production, Field Services and Merchant Energy. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. Our Pipelines, Production and Merchant Energy segment information for the years ended December 31, 2002 and 2001 has been restated as further discussed in Note 1, Restatement of Historical Financial Statements. In 2002 and 2003, we reclassified our petroleum markets and coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's operating results for all periods reflect this change.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the U.S. We conduct our activities primarily through seven wholly owned and five 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 North America. In the U.S., Production has onshore and coal seam operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey.

Our Field Services segment owns or has interests in 22 processing plants and related gathering facilities located in the south Texas and south Louisiana, as well as an ownership interest in GulfTerra.

Our Merchant Energy segment owns and has interests in domestic and international power assets, conducts energy marketing and trading activities and held a developing merchant LNG business. Through these business activities, we buy, sell and trade natural gas, power, crude oil, and other energy commodities throughout the world, and own or have interests in 68 power plants in 16 countries.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2003, 2002 and 2001.

We use 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 loss from continuing operations for each of the three years ended December 31:

	2003	2002 (Restated)	2001 (Restated)
		(In millions)	
Total EBIT	$ 639	$ (531)	$ 888
Interest and debt expense	(1,787)	(1,293)	(1,129)
Distributions on preferred interests of consolidated subsidiaries	(52)	(159)	(217)
Income taxes	584	649	70
Loss from continuing operations	$ (616)	$(1,334)	$ (388)

The following tables reflect our segment results as of and for each of the three years ended December 31:

	Segments As of or for the Year Ended December 31, 2003					
	Regulated	Unregulated				
	Pipelines	Production	Field Services	Merchant Energy	Corporate and Other[(1)]	Total
			(In millions)			
Revenue from external customers						
Domestic	$ 2,527	$ 202[(2)]	$1,153	$ 1,970	$ 52	$ 5,904
Foreign	2	56	2	529	—	589
Intersegment revenue	118	1,971[(2)]	374	(2,109)	(136)	218[(3)]
Operation and maintenance	720	350	110	760	77	2,017
Depreciation, depletion, and amortization	386	606	31	117	67	1,207
Ceiling test charges	—	76	—	—	—	76
(Gain) loss on long-lived assets	(10)	93	173	286	407	949
Western Energy Settlement	127	—	—	(25)	2	104
Operating income (loss)	$ 1,063	$ 944	$ (193)	$ (989)	$ (550)	$ 275
Earnings (losses) from unconsolidated affiliates	119	13	329	(100)	2	363
Other income	57	5	—	104	37	203
Other expense	(5)	—	(3)	(16)	(178)	(202)
EBIT	$ 1,234	$ 962	$ 133	$(1,001)	$ (689)	$ 639
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$(1,303)	$(1,303)
Cumulative effect of accounting changes, net of income taxes	(4)	(3)	(2)	—	—	(9)
Assets of continuing operations[(4)]						
Domestic	15,726	3,459	1,990	6,579	3,865	31,619
Foreign	27	746	—	3,182	141	4,096
Capital expenditures and investments in unconsolidated affiliates, net[(5)]	833	1,429	(15)	1,084	62	3,393
Total investments in unconsolidated affiliates	1,085	79	655	1,727	5	3,551

(1) Includes our Corporate and telecommunication activities and 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 record an intersegment revenue and operation and maintenance expense elimination, which is included in the "Corporate and Other" column, to remove intersegment transactions. Losses reflected in our Corporate activities include approximately $396 million related to the impairment of our telecommunication business in the second quarter of 2003, inclusive of a write-down of goodwill of $163 million. See Note 2 for an additional discussion of this impairment.

(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 affiliate EPME, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $1.4 billion (see Note 12).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital. Our Merchant Energy segment includes $1 billion to acquire remaining interest in Chaparral and Gemstone (see Note 3).

	Segments As of or for the Year Ended December 31, 2002					
	Regulated	Unregulated				
	Pipelines (Restated)	Production (Restated)	Field Services	Merchant Energy (Restated)	Corporate and Other(1)	Total (Restated)
	(In millions)					
Revenue from external customers						
Domestic	$ 2,389	$ 289(2)	$1,145	$ 2,072	$ 43	$ 5,938
Foreign	3	71	3	542	—	619
Intersegment revenue	218	1,643(2)	881	(2,205)	(177)	360(3)
Operation and maintenance	752	386	179	702	91	2,110
Depreciation, depletion and amortization	374	622	56	56	72	1,180
Ceiling test charges	—	128	—	—	—	128
(Gain) loss on long-lived assets	(13)	3	(179)	204	170	185
Western Energy Settlement	412	—	—	487	—	899
Operating income (loss)	$ 788	$ 698	$ 273	$(1,695)	$ (327)	$ (263)
Earnings (losses) from unconsolidated affiliates	(2)	7	18	(256)	7	(226)
Other income	34	1	3	60	99	197
Other expense	(4)	(3)	(5)	(127)	(100)	(239)
EBIT	$ 816	$ 703	$ 289	$(2,018)	$ (321)	$ (531)
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (365)	$ (365)
Cumulative effect of accounting changes, net of income taxes	79	—	—	(133)	—	(54)
Assets of continuing operations(4)						
Domestic	14,794	3,489	2,714	8,427	4,077	33,501
Foreign	59	661	14	3,567	198	4,499
Capital expenditures and investments in unconsolidated affiliates, net(5)	1,074	2,301	187	168	309	4,039
Total investments in unconsolidated affiliates	1,059	87	922	2,800	23	4,891

(1) Includes our Corporate and telecommunication activities and 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 record an intersegment revenue and operation and maintenance expense elimination, which is included in the "Corporate and Other" 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 affiliate EPME, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $4.1 billion (see Note 12).

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

	Segments As of or for the Year Ended December 31, 2001					
	Regulated	Unregulated				
	Pipelines (Restated)	Production (Restated)	Field Services	Merchant Energy (Restated)	Corporate and Other[1]	Total (Restated)
	(In millions)					
Revenue from external customers						
Domestic	$ 2,451	$ 154[2]	$1,809	$ 5,104	$ 380	$ 9,898
Foreign	2	46	4	261	—	313
Intersegment revenue	289	2,286[2]	740	(2,999)	(313)	3[3]
Operation and maintenance	777	354	251	398	284	2,064
Merger-related costs	291	47	46	17	1,092	1,493
Depreciation, depletion, and amortization	383	797	111	41	48	1,380
Ceiling test charges	—	2,143	—	—	—	2,143
Loss on long-lived assets	21	16	—	21	19	77
Operating income (loss)	$ 880	$(1,069)	$ 124	$ 1,762	$(1,406)	$ 291
Earnings (losses) from unconsolidated affiliates	136	(1)	72	220	10	437
Other income	28	3	5	198	54	288
Other expense	(12)	(1)	(5)	(23)	(87)	(128)
EBIT	$ 1,032	$(1,068)	$ 196	$ 2,157	$(1,429)	$ 888
Discontinued operations, net of income taxes	$ —	$ —	$ —	$ —	$ (85)	$ (85)
Extraordinary items, net of income taxes	(27)	—	(5)	(7)	65	26
Assets of continuing operations[4]						
Domestic	14,340	3,632	3,619	9,093	3,878	34,562
Foreign	98	629	17	4,147	32	4,923
Capital expenditures and investments in unconsolidated affiliates, net[5]	1,093	2,521	165	957	1,121	5,857
Total investments in unconsolidated affiliates	1,104	77	602	3,434	19	5,236

(1) Includes our Corporate and telecommunication activities and 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 record an intersegment revenue elimination, which is the only elimination included in the "Corporate and Other" 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 affiliate EPME, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

(4) Excludes assets of discontinued operations of $4.8 billion.

(5) Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

27. Supplemental Cash Flow Information

The following table contains supplemental cash flow information from continuing operations for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Interest paid, net of amounts capitalized	$ 1,657	$ 1,291	$ 1,378
Income tax payments (refunds)	23	(106)	56

Below is a detail of our short-term and long-term borrowings and repayments for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Short-term borrowings and repayments			
Net borrowings (repayments) of commercial paper and short-term credit facilities	$ —	$ 154	$ (783)
Net proceeds from the issuance of notes payable	84	—	—
Repayments of notes payable	(8)	(94)	(3)
Total	$ 76	$ 60	$ (786)
Long-term borrowings and repayments			
Net proceeds from the issuance of long-term debt	$ 3,633	$ 4,294	$ 3,110
Payments to retire long-term debt and other financing obligations	(2,824)	(1,777)	(1,856)
Repayments under revolving credit facilities	(650)	—	—
Other	(177)	(509)	(91)
Total	$ (18)	$ 2,008	$ 1,163

28. Investments in and Advances to 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 greater than our equity in the net assets of these investments by $6 million as of December 31, 2003, and by $230 million as of December 31, 2002. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and advances to our unconsolidated affiliates are as follows as of December 31:

	Country	Type of Entity	Net Ownership Interest	Investment 2003	Investment 2002	Advances 2003	Advances 2002
			(Percent)	(In millions)			
Domestic:							
Citrus	U.S.	Corporation	50	$ 650	$ 606	$ —	$ —
GulfTerra Energy Partners(1)	U.S.	LP(2)	—	599	776	—	—
Midland Cogeneration Venture(3)	U.S.	LP(2)	44	348	316	—	—
Great Lakes Gas Transmission(4)	U.S.	LP(2)	50	325	312	—	—
Bastrop Company(11)	U.S.	LLC(5)	50	73	121	—	—
Blue Lake Gas Storage	U.S.	GP(6)	75	30	26	—	—
CE Generation(7)	U.S.	LLC(5)	50	—	287	—	—
Chaparral Investors (Electron)(8)	U.S.	LLC(5)	—	—	256	—	700
Other Domestic Investments	U.S.	various	various	202	436	39	67
Total domestic				2,227	3,136	39	767
Foreign:							
Korea Independent Energy Corporation	South Korea	Corporation	50	220	206	—	—
Araucaria Power(9)	Brazil	LLC(5)	60	181	—	—	—
EGE Itabo	Dominican Republic	Corporation	25	87	87	—	—
UnoPaso(12)	Brazil	LLC(5)	50	73	80	—	—
Bolivia to Brazil Pipeline	Bolivia/Brazil	LLC(5)	8	66	53	—	—
Saba Power Company	Pakistan	LLC(5)	94	59	55	—	—
EGE Fortuna	Panama	Corporation	25	59	61	—	—
Meizhou Wan Generating	China	LLC(5)	25	63	56	—	—
Enfield Power	United Kingdom	LP(2)	25	55	50	—	—
Aguaytia Energy	Peru	LLC(5)	24	51	52	—	—
Habibullah Power	Pakistan	LLC(5)	50	48	57	90	99
Gasoducto del Pacifico Pipeline (Argentina to Chile)	Argentina/Chile	Corporation	22	37	69	—	—
Porto Velho(9)	Brazil	LLC(5)	50	(7)	—	290	—
Diamond Power (Gemstone)(10)	Brazil	LLC(5)	—	—	663	—	25
Other Foreign Investments	various	various	various	332	266	38	80
Total foreign				1,324	1,755	418	204
Total investments in and advances to unconsolidated affiliates				$3,551	$4,891	$457	$971

(1) Our ownership interest as of December 31, 2003 consists of 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. For a further discussion of GulfTerra, see page 178.
(2) LP represents Limited Partnership.
(3) Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.
(4) Includes a 46 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 4 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.
(5) LLC represents Limited Liability Company.
(6) GP represents General Partnership.
(7) We sold 100 percent of our interest in 2003.
(8) Consolidated on January 1, 2003.
(9) Included in Diamond Power (Gemstone) prior to the consolidation of Gemstone in April 2003.
(10) Consolidated in April 2003.
(11) In June 2004, we completed the sale of our interest in this investment.
(12) In July 2004, we purchased the remaining 50 percent interest in UnoPaso and began consolidating these operations.

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

	2003	2002	2001
		(In millions)	
Aguaytia Energy	$ 5	$ 3	$ 4
Alliance Pipeline Limited Partnership[1]	1	21	23
Bolivia to Brazil Pipeline	17	2	1
CE Generation[1]	—	26	33
Chaparral Investors (Electron)[2]	—	(62)	75
Citrus Corporation	43	43	40
Diamond Power (Gemstone)[3]	17	109	2
Eagle Point Cogeneration Partnership[4]	—	—	22
EGE Fortuna	3	6	3
GulfTerra Energy Partners L.P. (GulfTerra)	115	70	44
Enfield Power	2	(2)	18
Great Lakes Gas Transmission	57	63	55
Korea Independent Energy Corporation	29	24	20
Linden Venture L.P.[5]	98	—	—
Midland Cogeneration Venture	32	28	23
UnoPaso[6]	14	6	(1)
Saba Power Company	4	7	—
Samalayuca[7]	3	19	12
Other	80	82	87
Proportional share of income of investees	520	445	461
Impairment charges and gains and losses on sale of investments	(176)	(624)	(46)
Gain on issuance by GulfTerra of its common units	38	—	3
Other	(19)	(47)	19
Total earnings (losses) from unconsolidated affiliates	$ 363	$(226)	$437

(1) We sold our interest in these investments in 2002 and 2003.
(2) Consolidated in January 2003.
(3) Consolidated in April 2003.
(4) Consolidated in January 2002.
(5) Acquired in January 2003 as a part of the consolidation of Chaparral and sold in October 2003.
(6) In July 2004, we purchased the remaining 50 percent interest in UnoPaso and began consolidating these operations.
(7) We sold our interest in the power plant portion of this investment in December 2002.

Our impairment charges and gains and losses on sales of equity investments during 2003, 2002 and 2001 consisted of the following:

Investment	Pre-tax Gain (Loss) (In millions)	Cause of Impairments or Gain (Loss)
2003		
Gain on sale of interests in GulfTerra[1]	$ 266	Sale of various investment interests in GulfTerra
Chaparral	(207)	Decline in the investment's fair value based on developments in our power business and the power industry
Milford power facility[2]	(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.	(22)	Sale of investment in East Coast Power
Other investments	4	
Total	$(176)	
2002		
CAPSA/CAPEX	$(262)	Weak economic conditions in Argentina
EPIC Australia	(153)	Regulatory difficulties and the decision to discontinue further capital investment
CE Generation	(74)	Sale of investment
Aux Sable NGL	(47)	Sale of investment
Aqua de Cajon	(24)	Weak economic conditions in Argentina
PPN	(41)	Loss of economic fuel supply and payment default
Other investments	(23)	
Total	$(624)	
2001		
East Asia Power	$ (39)	Weak economic conditions in the Philippines and the decision to discontinue further capital investment
Fife Power	(35)	Weak economic conditions in the U.K. power market and the decision to discontinue further capital investment
Other investments	28	
Total	$ (46)	

(1) 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. See further discussion of GulfTerra on page 178.

(2) 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 $398 million and $258 million in 2003 and 2002, which includes $53 million and $24 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 $119 million, $26 million and $40 million in 2003, 2002 and 2001 and total assets of $1,108 million and $389 million as of December 31, 2003 and 2002.

	Year Ended December 31,		
	2003	2002	2001
		(Unaudited) (In millions)	
Operating results data:			
Operating revenues	$3,360	$2,486	$2,151
Operating expenses	2,309	1,632	1,391
Income from continuing operations	519	422	436
Net income	520	445	461

	December 31,	
	2003	2002
	(Unaudited) (In millions)	
Financial position data:		
Current assets	$1,024	$ 1,334
Non-current assets	8,001	10,520
Short-term debt	1,169	777
Other current liabilities	645	855
Long-term debt	1,892	4,448
Other non-current liabilities	1,703	1,083
Minority interest	71	30
Equity in net assets	3,545	4,661

The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates:

	2003	2002	2001
		(In millions)	
Operating revenue	$124	$ 59	$215
Other revenue — management fees	13	192	150
Cost of sales	119	142	92
Reimbursement for operating expenses	136	186	164
Other income	10	18	20
Interest income	11	30	45
Interest expense	2	42	50

Chaparral and Gemstone

As of December 31, 2002, we held equity investments in Chaparral and Gemstone. During the first and second quarters of 2003, we acquired the remaining third party equity interests and all of the voting rights in both of these entities. As discussed in Note 3, we consolidated Chaparral effective January 1, 2003 and Gemstone effective April 1, 2003. The following tables summarize our overall investments in Chaparral and Gemstone as of December 31, 2002.

	Chaparral	Gemstone
	(In millions)	
Equity investment	$ 256	$ 663
Credit facilities receivable	377	25
Notes receivable	323	—
Debt securities payable	(79)	(122)
Contingent interest promissory notes payable	(173)	—
Total net investment	$ 704	$ 566

GulfTerra

A subsidiary in our Field Services segment serves as the general partner of GulfTerra, a publicly traded master limited partnership. We had the following interests in GulfTerra as of December 31:

	2003		2002	
	Book Value	Ownership	Book Value	Ownership
	(In millions)	(Percent)	(In millions)	(Percent)
One Percent General Partner[1]	$194	100.0	$189	100.0
Common Units[2]	251	17.8	259	26.5
Series B Units[3]	—	—	158	100.0
Series C Units[4]	335	100.0	351	100.0
Total	$780		$957	

(1) We have $181 million of indefinite-lived intangible assets related to our general partner interest (see Note 2) as of December 31, 2003 and 2002. We also have $96 million recorded as minority interest related to the effective general partner interest acquired by Enterprise in December 2003. This reduced our effective ownership interest in the general partner to 50 percent.

(2) The remaining units are owned by public holders, including the partnership employees and management, none of which individually own more than 10 percent.

(3) In October 2003, GulfTerra redeemed all of the Series B preference units that we owned for $156 million. We recorded a $11 million loss on this redemption.

(4) We own all of the Series C units of GulfTerra.

As the owner of the managing member interest and a 50 percent ownership interest in the general partner, Field Services manages GulfTerra's daily operations and performs all of GulfTerra's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributes to our income through our general partner interest and our ownership of common and preference units. We do not have any loans to or from GulfTerra.

A majority of the members of the Board of Directors governing GulfTerra are independent of us and its audit and conflicts committee and governance and compensation committee are completely comprised of independent board members.

In October 2003, we sold a 9.9 percent in the consolidated company that owns the one percent general partner interest of GulfTerra to Goldman Sachs for $88 million. We repurchased this interest in December 2003, prior to the announcement of GulfTerra's merger with Enterprise for $92 million in cash and $28 million of GulfTerra's common units. In addition, GulfTerra redeemed all of the Series B preference units that we owned for $156 million. Finally, as part of the overall transactions, GulfTerra released us from our obligation to repurchase the Chaco processing facility and we contributed communications assets to GulfTerra. Prior to the transaction, we would have been obligated to repurchase the Chaco facility for approximately $77 million in 2021.

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise announced that they had executed definitive agreements to merge to form the second largest publicly traded energy partnership in the U.S. The general partner of the combined partnership would be jointly owned by us and affiliates of privately held Enterprise Products Company, with each owning a 50 percent interest.

The definitive agreements included three transactions: (i) Enterprise agreed to acquire a 50 percent limited voting interest in GulfTerra Energy Company, L.L.C. (GulfTerra's general partner) from us for $425 million in cash, giving it an effective 50 percent ownership in GulfTerra's general partner, (ii) we agreed to exchange our remaining general partner interest for a 50 percent interest in the combined general partner of GulfTerra and Enterprise Partners, (iii) Enterprise agreed to pay us $500 million in cash for 2.9 million common units and all of GulfTerra's Series C units that we own, and we will exchange our remaining GulfTerra common units for approximately 13.5 million Enterprise common units, based on the 1.81 exchange ratio specified in the merger agreement. In April 2004, we amended our agreement with Enterprise Products Company to reduce our interest in the general partner of the combined entity to 9.9 percent, in exchange for an additional payment to us of $370 million when the merger is completed.

On July 29, 2004, GulfTerra's unitholders approved the adoption of its merger agreement with Enterprise. GulfTerra expects the completion of the merger to occur in the third quarter of 2004, although it remains subject to review by the Federal Trade Commission (FTC) and the satisfaction of other conditions to close.

The sale of 50 percent of our interest in GulfTerra's general partner was completed in December 2003, and we recognized a $269 million gain on the sale, which is net of $45 million of total services or payments we have agreed to provide during the three years following closing of the transactions. The cash flows from this sale were reflected in our 2003 cash flow statement as an investing activity and $84 million of the proceeds were reflected as an issuance of a minority interest in our balance sheet.

Concurrent with the closing of the merger, Enterprise will acquire nine natural gas processing plants from us for $150 million in cash. These plants are located in south Texas. For a further discussion of the impairment of these assets, see Note 7.

During each of the three years ended December 31, 2003, we conducted the following transactions with GulfTerra:

	2003	2002	2001
		(In millions)	
Revenues received from GulfTerra			
Field Services	$ 5	$ 1	$ —
Merchant Energy	28	19	28
Production	—	3	7
	$ 33	$ 23	$ 35
Expenses paid to GulfTerra			
Pipelines	$ —	$ —	$ 1
Field Services	75	97	32
Merchant Energy	30	93	17
Production	9	9	4
	$114	$199	$ 54
Reimbursements received from GulfTerra			
Field Services	$ 91	$ 60	$ 33

In 2001, as a result of our merger with Coastal, GulfTerra sold its interest in several offshore assets including seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from these sales were approximately $135 million and resulted in a loss of approximately $25 million. As consideration for these sales, we committed to pay GulfTerra a series of payments totaling $29 million, and were required to contribute $40 million to a trust related to one of the assets sold by GulfTerra. These payments were recorded as merger-related costs.

During 2002, we sold a total of $1.5 billion in assets to the partnership, including gathering, processing and transmission assets and substantially all our assets in the San Juan Basin. One of the San Juan Basin assets included in this transaction was our remaining interests in the Chaco cryogenic plant. In addition to $414 million of cash, we received the Series C units we now own. In addition, in 2003, we exchanged communications assets for a release of our obligation to repurchase the Chaco cryogenic plant in 2021. We recognized a net gain on this transaction of $67 million (see Note 7).

As of December 31, 2003, we have a net deferred gain recorded in other current and non-current liabilities on our balance sheet related to the San Juan and Chaco sales, along with other asset sales, totaling $105 million. We deferred these gains to the extent of our overall ownership interest in GulfTerra. Upon completion of the merger with Enterprise, a portion of these deferred amounts will be transferred to income. In connection with the sales of our transmission assets to GulfTerra, we agreed to reimburse GulfTerra for a portion of its future pipeline integrity costs related to those assets through 2006. At the time of these 2002 sales, we were unable to estimate the liability associated with this obligation as we and GulfTerra were in the early stages of our pipeline integrity programs. In 2003, we amended this agreement to clarify the types and amounts of reimbursable costs, and also began reviewing GulfTerra's pipeline integrity project's results. This review continued during 2004. Based on those reviews, and on our experience to date related to our own pipeline integrity projects, we determined that the obligation was both probable and could be estimated. As a result, we recorded a $5 million current liability and a $69 million non-current liability related to this agreement. We have not provided any other material guarantees, either monetary or performance, on behalf of or for the benefit of GulfTerra nor do we have any other liabilities other than normal course of business or those arising out of our role as the general partner in GulfTerra.

In 2001, we sold the partnership NGL transportation and fractionation assets and an investment in Deepwater Holdings, an entity that owned several pipeline gathering systems in the Gulf of Mexico. The majority of these assets had been acquired by us one year earlier and accordingly had been recorded at their fair value. As a result, proceeds from these sales were $255 million and no gains or losses were recognized.

Below is a detail of these sales and related gains or losses recognized:

Transaction	Proceeds	Realized Gain/(Loss)
	(In millions)	
2003		
Series B preference units	$156	$(11)
Common units	23	8
50 percent of general partnership interest in GulfTerra and common units	421	269
2002		
San Juan Basin gathering, treating, and processing assets	766	219
Texas and New Mexico midstream assets	735	(9)
2001		
Texas fractionation facilities	133	—
Chaco processing agreement	122	—

In these sales transactions, specific procedures have been instituted for evaluating these transactions to ensure that they are in the best interests of us and the partnership and are based on fair values. These procedures require our Board of Directors to evaluate and approve, as appropriate, transactions with GulfTerra. In addition, a special committee comprised of the GulfTerra general partner's independent directors evaluates the transactions on GulfTerra's behalf. This typically involves engaging an independent financial advisor to assist with the evaluation and to opine on its fairness.

Included as supplemental information to these financial statements are the consolidated financial statements of GulfTerra Energy Partners, L.P. and Subsidiaries for the years ended December 31, 2003, 2002 and 2001.

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 $102 million. We own a 48.33 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. We also own a 24.99 percent ownership interest in a 416 MW power generating complex known as Itabo. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso of approximately 84 percent against the U.S. dollar by September 1, 2004 and an increase in the local inflation rate of approximately 43 percent during 2003 and an additional 33 percent through September 1, 2004. The current government administration is currently in negotiations with the IMF to reinstate a stand-by agreement that is intended to restore confidence in the banking system and economic policy framework, stabilize the exchange rate and alleviate the ongoing liquidity crisis in the country. 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, as well as 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. We currently believe that the economic difficulties in the Dominican Republic can be mitigated with support from the IMF and through the implementation of major structural reforms, including a fiscal package that was approved by the Congress the first week of September 2004 and that is pending a second reading and final approval by the Senate expected to take place by the end of September 2004.

Meizhou Wan Power Project. As of December 31, 2003, we owned a 24.8 percent equity interest in a 734 MW, coal-fired power generating project, Meizhou Wan Generating, located in Fuzhou, People's Republic of China. Our investment in the project was $63 million at December 31, 2003, and we have also issued guarantees and letters of credit in favor of the project's lenders in the amount of $21 million. The project declared that it was ready for commercial operations in August 2001; however, the provincial government, who buys all of the power generated by the project, refused to accept the project for commercial operations. This dispute was resolved with the signing of an amended and restated long-term power purchase agreement effective January 1, 2004, which provides for a certain minimum annual offtake obligation at an agreed tariff and a lower tariff for power generated by the project in excess of the minimum offtake obligation. With this new power purchase agreement, the project was able to restructure the project debt in 2004 with new local financing on more favorable terms, thus achieving a lower cost structure for the project. The new project debt is collateralized only by the project's assets and is non-recourse to us and the guarantees issued to the prior lenders were canceled. In connection with this refinancing, we acquired an additional 1.4 percent interest in the project and issued an $11 million guarantee to the project related to a potential claim by one of its vendors as of September 2004.

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 $33 million of its fuel payments, including $5 million of interest, under this agreement as of December 31, 2003. 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 $28 million in 2003 associated with the amounts due to us under the fuel supply agreement. We may incur additional losses of up to $16 million in the future if Berkshire continues to delay payments under the fuel supply agreement.

For contingent matters impacting our investments in Brazil, see Note 22.

29. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, as restated to reflect the impacts of the revisions of our natural gas and oil reserves and for the accounting for our natural gas and oil hedges as further described in Note 1 is summarized below.

	Quarters Ended				
	March 31 (Restated)	June 30 (Restated)	September 30 (Restated)	December 31	Total
	(In millions, except per common share amounts)				
2003[1]					
Operating revenues	$1,844	$ 1,574	$1,724	$1,569	$ 6,711
Ceiling test charges	1	20	47	8	76
Loss on long-lived assets	22	401	54	472	949
Western Energy Settlement	—	123	(20)	1	104
Operating income (loss)	268	(294)	447	(146)	275
Income (loss) from continuing operations	(200)	(319)	72	(169)	(616)
Discontinued operations, net of income taxes	(222)	(917)	(48)	(116)	(1,303)
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	$(0.33)	$ (0.53)	$ 0.12	$(0.28)	$ (1.03)
Discontinued operations, net of income taxes	(0.37)	(1.54)	(0.08)	(0.19)	(2.18)
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 and coal mining operations are classified as discontinued operations. See Note 12 for further discussion.

	Quarters Ended				
	March 31 (Restated)	June 30 (Restated)	September 30 (Restated)	December 31 (Restated)	Total (Restated)
	(In millions, except per common share amounts)				
2002[1]					
Operating revenues	$2,478	$1,750	$1,615	$ 1,074	$ 6,917
Ceiling test charges	27	98	—	3	128
(Gain) loss on long-lived assets	(15)	(12)	3	209	185
Western Energy Settlement	—	—	—	899	899
Operating income (loss)	515	414	250	(1,442)	(263)
Income (loss) from continuing operations	(107)	153	(12)	(1,368)	(1,334)
Discontinued operations, net of income taxes	60	(116)	(94)	(215)	(365)
Cumulative effect of accounting changes, net of income taxes	154	14	—	(222)	(54)
Net income (loss)	$ 107	$ 51	$ (106)	$(1,805)	$(1,753)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	$(0.20)	$ 0.29	$(0.02)	$ (2.31)	$ (2.38)
Discontinued operations, net of income taxes	0.12	(0.22)	(0.16)	(0.36)	(0.65)
Cumulative effect of accounting changes, net of income taxes	0.29	0.03	—	(0.37)	(0.10)
Net income (loss)	$ 0.21	$ 0.10	$(0.18)	$ (3.04)	$ (3.13)

(1) Our petroleum markets and coal mining operations are classified as discontinued operations. See Note 12 for further discussion.

30. 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, condensate and natural gas liquids, primarily in North America. In the U.S., we have onshore and coal seam operations and properties in 20 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Australia, Bolivia, Brazil, Canada, Hungary, Indonesia and Turkey. Our financial information and our natural gas and oil reserve information presented below has been restated to reflect the impacts of revisions of our natural gas and oil reserves, and for the accounting for our natural gas and oil hedges as further described in Note 1 is summarized below.

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

	United States	Canada[1]	Brazil	Other Countries[1] [2]	Worldwide
2003					
Natural gas and oil properties:					
Costs subject to amortization	$14,036	$ 861	$146	$47	$15,090
Costs not subject to amortization	371	146	117	7	641
	14,407	1,007	263	54	15,731
Less accumulated depreciation, depletion and amortization	11,204	650	58	20	11,932
Net capitalized costs[3]	$ 3,203	$ 357	$205	$34	$ 3,799
2002 (Restated)					
Natural gas and oil properties:					
Costs subject to amortization	$13,283	$ 608	$ —	$ 8	$13,899
Costs not subject to amortization	594	177	—	—	771
	13,877	785	—	8	14,670
Less accumulated depreciation, depletion and amortization	10,883	456	—	3	11,342
Net capitalized costs	$ 2,994	$ 329	$ —	$ 5	$ 3,328

(1) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

(2) Includes international operations in Hungary and Indonesia.

(3) In January 2003, we adopted SFAS No. 143. Included in our net capitalized costs at December 31, 2003 are SFAS No. 143 asset values of $124 million for the U.S. and less than $1 million for other countries. Prior period presentation was not adjusted as amounts were adjusted through a one-time cumulative adjustment which is further discussed on Note 2.

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

	United States	Canada[1]	Brazil	Other Countries[1][2]	Worldwide
2003					
Property acquisition costs					
Proved properties	$ 10	$ 1	$—	$—	$ 11
Unproved properties	35	10	4	—	49
Exploration costs[3]	467	44	95	11	617
Development costs[3]	668	57	—	2	727
Total costs expended	1,180	112	99	13	1,404
Plus: Asset retirement obligation costs[4]	124	—	—	—	124
Less: Actual retirement expenditures	(4)	—	—	—	(4)
Total costs incurred	$1,300	$112	$99	$13	$1,524
2002 (Restated)[5]					
Property acquisition costs					
Proved properties	$ 362	$ 6	$—	$—	$ 368
Unproved properties	29	7	—	—	36
Exploration costs	524	70	—	—	594
Development costs	1,242	80	—	2	1,324
Total costs incurred	$2,157	$163	$—	$ 2	$2,322
2001 (Restated)[5]					
Property acquisition costs					
Proved properties	$ 91	$232	$—	$—	$ 323
Unproved properties	44	16	—	—	60
Exploration costs	332	22	—	—	354
Development costs	1,374	102	—	—	1,476
Total costs incurred	$1,841	$372	$—	$—	$2,213

(1) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

(2) Includes international operations in Hungary and Indonesia.

(3) Excludes $130 million that was paid by third parties under net profits interest agreements as described beginning on page 189.

(4) In January 2003, we adopted SFAS No. 143. Prior period presentation was not adjusted as amounts were adjusted through a one-time cumulative adjustment of approximately $3 million, after tax, which is further discussed in Notes 2 and 8.

(5) We have reclassified some of our development costs to exploration costs as a result of the restatement of our natural gas and oil reserves.

In our January 1, 2004 reserve report, the amounts estimated to be spent in 2004, 2005 and 2006 to develop our worldwide booked proved undeveloped reserves are $544 million, $404 million and $487 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2003, pending determination of proved reserves. Capitalized interest of $18 million, $10 million, and $4 million for the years ended December 31, 2003, 2002 and 2001 is included in the presentation below (in millions):

	Cumulative Balance December 31,	Costs Excluded for Years Ended December 31,			Cumulative Balance December 31,
	2003	2003	2002	2001	2000
Worldwide[1][2]					
Acquisition	$319	$ 73	$ 90	$118	$38
Exploration	257	174	52	21	10
Development	65	5	27	31	2
	$641	$252	$169	$170	$50

(1) Includes operations in the U.S., Canada, Brazil, Hungary and Indonesia.
(2) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

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 2004 through 2007. For the U.S., total amortization expense per Mcfe, including ceiling test charges, was $1.40, $1.05, and $4.09 in 2003, 2002, and 2001. Excluding ceiling test charges, amortization expense would have been $1.40, $1.05 and $1.19 per Mcfe in 2003, 2002, and 2001. For Canada, total amortization expense per Mcfe, including ceiling test charges, was $5.30, $4.81 and $16.15 in 2003, 2002 and 2001. Excluding ceiling test charges, amortization expense would have been $1.71, $0.90, and $2.54 per Mcfe in 2003, 2002 and 2001. In January 2003, we adopted SFAS No. 143. For further discussion, see Note 2. Accretion expense per Mcfe attributable to SFAS No. 143 was $0.06 in 2003 and is included in depreciation, depletion and amortization expense.

All of our proved properties, with the exception of the proved reserves in Brazil, Hungary and Indonesia, are located in North America (U.S. and Canada).

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves at December 31, 2003 are presented below. Information in these tables are based on the reserve report dated January 1, 2004, prepared internally by us. Ryder Scott Company and Huddleston & Co., Inc., independent petroleum engineering firms, performed independent reserve estimates for 90 percent and 10 percent of our properties, respectively. The total estimate of proved reserves prepared independently by Ryder Scott Company and Huddleston & Co., Inc., was within five percent of our internally prepared estimates for 2003 presented in the tables below. The information at December 31, 2003, is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual product acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. The tables below exclude reserve information related to the following equity interests: our ownership interest in UnoPaso (UnoPaso in Brazil); the Merchant Energy segment's interests in Sengkang in Indonesia, and Aguaytia in Peru; and the Field Services segment's interest in GulfTerra. Combined proved natural gas and liquids reserve balances for these equity investment interests were 255,278 MMcf and 7,105 MBbls, respectively, or natural gas equivalents of 297,909 MMcfe, all net to our ownership interests. Reserve information as of and for the years ended December 31, 2001 and 2002 in the following tables has been restated (for a further discussion, see Note 1). In July 2004, we acquired the other 50 percent interest in Uno Paso and began consolidating these operations.

	Natural Gas (in Bcf)			
	United States	Canada[1]	Other Countries[1][2]	Worldwide
Net proved developed and undeveloped reserves[3]				
January 1, 2001 (Restated)	2,666	30	—	2,696
Revisions of previous estimates[4]	(116)	4	—	(112)
Extensions, discoveries and other	824	14	—	838
Purchases of reserves in place	20	46	—	66
Sales of reserves in place	(43)	—	—	(43)
Production	(552)	(13)	—	(565)
December 31, 2001 (Restated)	2,799	81	—	2,880
Revisions of previous estimates[4]	(155)	1	—	(154)
Extensions, discoveries and other	829	54	5	888
Purchases of reserves in place	142	—	—	142
Sales of reserves in place	(657)	(23)	—	(680)
Production	(470)	(17)	—	(487)
December 31, 2002 (Restated)	2,488	96	5	2,589
Revisions of previous estimates[4]	(24)	2	—	(22)
Extensions, discoveries and other	405	36	31	472
Purchases of reserves in place	2	—	—	2
Sales of reserves in place[5]	(471)	(22)	—	(493)
Production	(339)	(15)	(1)	(355)
December 31, 2003	2,061	97	35	2,193
Proved developed reserves				
December 31, 2001 (Restated)	2,091	70	—	2,161
December 31, 2002 (Restated)	1,799	84	—	1,883
December 31, 2003	1,428	87	4	1,519

(1) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

(2) Includes international operations in Hungary and Indonesia.

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

(4) Revisions reflect a number of items such as product price changes and changes in product differentials.

(5) Sales of reserves in place include 28,779 Mcf of natural gas conveyed to third parties under net profits interest agreements as described beginning on page 189.

	Liquids[1] (in MBbls)				
	United States	Canada[2]	Brazil	Other Countries[2][3]	Worldwide
Net proved developed and undeveloped reserves[4]					
January 1, 2001 (Restated)	69,660	410	—	—	70,070
Revisions of previous estimates[5]	(6,477)	1,309	—	—	(5,168)
Extensions, discoveries and other	24,711	296	—	—	25,007
Purchases of reserves in place	22	3,857	—	—	3,879
Sales of reserves in place	(68)	(2)	—	—	(70)
Production	(13,821)	(561)	—	—	(14,382)
December 31, 2001 (Restated)	74,027	5,309	—	—	79,336
Revisions of previous estimates[5]	(737)	(103)	—	—	(840)
Extensions, discoveries and other	14,741	288		—	15,029
Purchases of reserves in place	62	—	—	—	62
Sales of reserves in place	(11,670)	(2,062)	—	—	(13,732)
Production	(16,462)	(1,053)	—	—	(17,515)
December 31, 2002 (Restated)	59,961	2,379	—	—	62,340
Revisions of previous estimates[5]	(1,917)	1	—	—	(1,916)
Extensions, discoveries and other	6,795	2,463	20,543	1,742	31,543
Purchases of reserves in place	32	—	—	—	32
Sales of reserves in place[6]	(4,832)	(1,548)	—	—	(6,380)
Production	(11,683)	(309)	—	—	(11,992)
December 31, 2003	48,356	2,986	20,543	1,742	73,627
Proved developed reserves					
December 31, 2001 (Restated)	59,654	4,378	—	—	64,032
December 31, 2002 (Restated)	46,080	2,379	—	—	48,459
December 31, 2003	36,909	1,709	—	—	38,618

(1) Includes oil, condensate and natural gas liquids. Our year end 2003 natural gas liquids were 18,550 MBbls.

(2) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

(3) Includes international operations in Hungary and Indonesia.

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

(5) Revisions reflect a number of items such as product price changes and changes in product differentials.

(6) Sales of reserves in place include 1,292 MBbl of liquids conveyed to third parties under net profits interest agreements as described beginning on page 189.

There are considerable uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. 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, the 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, 2003.

In 2003, we entered into agreements to sell interests in a maximum of 124 wells in two packages to a subsidiary of Lehman Brothers and a wholly owned subsidiary of Nabors Industries, Ltd. As the wells are developed, these parties will pay 70 percent of the drilling and completion costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, these parties 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 proportionally reduced 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 their costs or any return on their investment. All parties to the agreement have the right to cease participation in the agreement at any time. Upon ceasing participation in the agreement, they will continue to receive their net profits interest on wells previously started, but will relinquish their right to participate in any future wells. As of December 31, 2003, we have sold interests in 31 wells with total production of 28,779 MMcf of natural gas and 1,292 MBbl of natural gas liquids to them under the agreement. They have paid $130 million of drilling and development costs and were paid $9 million of the revenues net of $1 million of expenses associated with these wells for the year ended December 31, 2003. One party has subsequently terminated its participation in one of the programs based on drilling results on a portion of the wells in the package.

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

	United States	Canada[1]	Brazil	Other Countries[2]	Worldwide
2003					
Net Revenues					
Sales to external customers	$ 191	$ 38	$—	$ 1	$ 230
Affiliated sales	1,867	30	—	—	1,897
Total	2,058	68	—	1	2,127
Production costs[3]	(229)	(8)	—	—	(237)
Depreciation, depletion and amortization[4]	(575)	(29)	—	(1)	(605)
Ceiling test and other charges	—	(74)	(5)	—	(79)
	1,254	(43)	(5)	—	1,206
Income tax (expense) benefit	(449)	15	2	—	(432)
Results of operations from producing activities	$ 805	$ (28)	$(3)	$—	$ 774
2002 (Restated)[5]					
Net Revenues					
Sales to external customers	$ 134	$ 48	$—	$—	$ 182
Affiliated sales	1,677	20	—	—	1,697
Total	1,811	68	—	—	1,879
Production costs[3]	(284)	(18)	—	—	(302)
Depreciation, depletion and amortization	(599)	(21)	—	—	(620)
Ceiling test and other charges	2	(95)	—	—	(93)
	930	(66)	—	—	864
Income tax (expense) benefit	(327)	28	—	—	(299)
Results of operations from producing activities	$ 603	$ (38)	$—	$—	$ 565
2001 (Restated)[5]					
Net Revenues					
Sales to external customers	$ 313	$ 45	—	$—	$ 358
Affiliated sales	2,012	1	—	—	2,013
Total	2,325	46	—	—	2,371
Production costs[3]	(322)	(12)	—	—	(334)
Depreciation, depletion and amortization	(754)	(42)	—	—	(796)
Ceiling test and other charges	(1,844)	(225)	—	—	(2,069)
	(595)	(233)	—	—	(828)
Income tax (expense) benefit	220	98	—	—	318
Results of operations from producing activities	$ (375)	$(135)	$—	$—	$ (510)

(1) As of September 2004, we have sold our production operations in Canada.
(2) Includes international operations in Hungary.
(3) Includes lease operating costs and production related taxes (including ad-valorem and severance taxes).
(4) In January 2003, we adopted SFAS No. 143, which is further discussed in Note 2. Our 2003 depreciation, depletion and amortization includes accretion expense for SFAS No. 143 asset retirement obligations of $23 million for the U.S. and less than $1 million for other countries.
(5) Amounts restated include net revenues, depreciation, depletion and amortization expenses, ceiling test and other charges, income taxes and related subtotals and totals.

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

	United States	Canada[1]	Brazil	Other Countries[1][2]	Worldwide
2003					
Future cash inflow[3]	$13,302	$ 607	$ 588	$ 141	$14,638
Future production costs	(3,025)	(124)	(65)	(44)	(3,258)
Future development costs	(1,325)	(11)	(236)	(49)	(1,621)
Future income tax (expenses) benefits	(1,695)	(28)	(75)	3	(1,795)
Future net cash flows	7,257	444	212	51	7,964
10% annual discount for estimated timing of cash flows	(2,449)	(154)	(128)	(21)	(2,752)
Standardized measure of discounted future net cash flows	$ 4,808	$ 290	$ 84	$ 30	$ 5,212
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,759	$ 290	$ 84	$ 30	$ 5,163
2002 (Restated)					
Future cash inflows[3]	$12,847	$ 458	$ —	$ 12	$13,317
Future production costs	(2,924)	(111)	—	(2)	(3,037)
Future development costs	(1,361)	(5)	—	(3)	(1,369)
Future income tax expenses	(1,960)	(4)	—	—	(1,964)
Future net cash flows	6,602	338	—	7	6,947
10% annual discount for estimated timing of cash flows	(2,293)	(117)	—	(1)	(2,411)
Standardized measure of discounted future net cash flows	$ 4,309	$ 221	$ —	$ 6	$ 4,536
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,266	$ 221	$ —	$ 6	$ 4,493
2001 (Restated)					
Future cash inflows[2][4]	$ 8,051	$ 301	$ —	$ —	$ 8,352
Future production costs	(2,489)	(107)	—	—	(2,596)
Future development costs	(1,196)	(17)	—	—	(1,213)
Future income tax expenses	(136)	—	—	—	(136)
Future net cash flows	4,230	177	—	—	4,407
10% annual discount for estimated timing of cash flows	(1,501)	(65)	—	—	(1,566)
Standardized measure of discounted future net cash flows	$ 2,729	$ 112	$ —	$ —	$ 2,841
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 2,933	$ 112	$ —	$ —	$ 3,045

(1) As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.
(2) Includes international operations in Hungary and Indonesia.
(3) Excludes $104 million and, $85 million of future net cash outflows related to hedging activities for the years of 2003 and 2002.
(4) Excludes $255 million of future net cash inflows related to hedging activities for the year of 2001.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end commodity prices, adjusted for transportation and other charges. At December 31, 2003, the prices used were $31.10 per Bbl of oil, $5.79 per Mcf of gas and $23.53 per Bbl of natural gas liquids. 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 standardized measure of discounted future net cash flows (in millions) excluding the effects of hedging activities:

	Years Ended December 31,[1]		
	2003	2002 (Restated)	2001 (Restated)
Sales and transfers of natural gas and oil produced net of production costs	$(1,890)	$(1,575)	$ (2,037)
Net changes in prices and production costs	1,654	3,393	(5,199)
Extensions, discoveries and improved recovery, less related costs	1,262	1,673	846
Changes in estimated future development costs	(17)	25	144
Previously estimated development costs incurred during the period	220	278	52
Revisions of previous quantity estimates	(87)	(347)	(145)
Accretion of discount	549	287	823
Net change in income taxes	148	(935)	2,044
Purchases of reserves in place	5	284	93
Sales of reserves in place	(1,310)	(1,491)	(25)
Change in production rates, timing and other	142	103	78
Net change	$ 676	$ 1,695	$ (3,326)

(1) Includes operations in the U.S., Canada, Brazil, Hungary and Indonesia. As of September 2004, we have sold our production operations in Canada and substantially all of our operations in Indonesia.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
El Paso Corporation:

In our opinion, the consolidated financial statements listed in the Index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso Corporation and its subsidiaries (the "Company") at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, the 2002 and 2001 consolidated financial statements have been restated to reflect the financial statement impact of the revision in the Company's estimates of its proved natural gas and oil reserves and to change the accounting for certain derivative transactions. The Company's plans with regard to its current liquidity position are also discussed in Note 1.

As discussed in Notes 2, 5 and 8, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* on January 1, 2003; SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities* on January 1, 2003; SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; 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. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2*, on October 1, 2002; and SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* on January 1, 2001.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
September 28, 2004

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2003, 2002 and 2001
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
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) (4)	(13)	389
Regulatory reserves	34	48	(59) (5)	1	24
2001					
Allowance for doubtful accounts	$ 48	$ 77	$ (7) (1)	$ (1)	$ 117
Valuation allowance on deferred tax assets	9	19(3)	—	—	28
Legal reserves	259	43	(30) (5)	(123) (7)	149
Environmental reserves	303	156	(21) (5)	30	468
Regulatory reserves	48	(1)	(2) (5)	(11)	34

(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 and foreign 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 (including approximately $568 million from escrow) and correspondingly reduced our liability by this amount.

(5) Relates primarily to payments for various litigation reserves, 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.

(7) Relates to purchase price adjustments for the legal reserves related to our 2001 PG&E acquisition.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

In February 2004, we completed the annual review of our December 31, 2003 natural gas and oil reserve estimates. As a result of this review, we reduced our proved natural gas and oil reserve estimates by approximately 1.8 trillion cubic feet. In May 2004, we announced that, after further review and the completion of an independent investigation into the factors that led to this significant reserve adjustment, we believed that this reserve adjustment related to prior periods and the financial statement amounts derived from these estimates would require a restatement in prior period financial statements. The results of this independent investigation indicated that, during the period from the beginning of 1999 and into 2003, certain employees used aggressive and, at times, unsupportable methods to book proved reserves. In addition, the investigation concluded that certain employees provided proved reserve estimates that they knew or should have known were incorrect at the time they were reported. In August 2004, we also determined we had not properly accounted for many of the hedges of our anticipated natural gas production and certain other derivative transactions. Consequently, we have restated our historical financial information for the years from 1999 through 2002 and for the first nine months of 2003 to properly reflect the reserve adjustments in historical periods and to correct the accounting for many of our production hedges and certain other derivatives. This restatement, as well as specific information regarding its impact, is discussed in Item 8, Financial Statements and Supplementary Data, Note 1.

We have identified deficiencies in our internal controls that did not prevent the overstatement of our natural gas and oil reserves. These deficiencies, which we believe constituted a material weakness in our internal controls over financial reporting, included a weak control environment surrounding the booking of our natural gas and oil reserves in the Production segment, inadequate controls over system access, inadequate documentation of policies and procedures, and ineffective controls to monitor compliance with existing policies and procedures.

Our management, at the direction of our Board of Directors, is actively working to improve the control environment and to implement controls and procedures that will ensure the integrity of our reserve booking process. As a first step in that process, individuals have been added to our Board of Directors and executive management team with extensive experience in the natural gas and oil industry, and with experience in the preparation of natural gas and oil reserve estimates. In addition, we have completed the implementation of the following controls:

- Formation of an internal committee to provide oversight of the reserve estimation process, which will be staffed with appropriate technical, financial reporting and legal expertise;
- Continued use of an independent third-party engineering firm that will be selected by and report annually to the Audit Committee of the Board of Directors with a subsequent report by the Audit Committee to the full Board of Directors;
- Formation of a centralized reserve reporting function, staffed primarily with newly hired personnel that have extensive industry experience, that is separated from the operating divisions and reports to the president of Production and Non-regulated Operations;
- Restriction of security access to the reserve system to the centralized reserve reporting staff; and
- Revisions in our documentation of the procedures and controls for estimating proved reserves.

We expect to have the following additional controls fully in place by December 31, 2004:

- Improved training regarding SEC guidelines for booking proved reserves; and
- Enhanced internal audit reviews.

In a review of the events that led to the inaccurate accounting for many of our production hedges and certain other hedge transactions, we identified weaknesses in our interpretation and application of complex accounting standards. Additionally, we insufficiently documented the basis for our application of complex accounting standards, and we failed to monitor factors that could impact our accounting decisions. Finally, we determined that we did not establish or communicate formal policies or procedures governing the execution of our hedge positions to the relevant people responsible for executing the transactions. Collectively, we believe these deficiencies constituted a material weakness in our internal controls. In the future, we will take steps to ensure that accounting conclusions involving interpretation of complex accounting standards are thoroughly documented and identify the critical factors that support the basis for our conclusion. We will also take steps to ensure that the factors on which we rely are validated and adequately evidenced. In addition, we will, where necessary, formalize policies and procedures to ensure consistent and appropriate execution of transactions. Finally, we will implement monitoring activities, where necessary, to ensure ongoing compliance where factors could change that would impact our accounting conclusions. We believe that all of these remedial actions will be implemented by December 31, 2004.

During 2003, we initiated a project to ensure compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX), which will apply to us at December 31, 2004. This project entailed a detailed review and documentation of the processes that impact the preparation of our financial statements, an assessment of the risks that could adversely affect the accurate and timely preparation of those financial statements, and the identification of the controls in place to mitigate the risks of untimely or inaccurate preparation of those financial statements. Following the documentation of these processes, which was substantially concluded by December 2003, we initiated an internal review or "walk-through" of these financial processes by the financial management responsible for those processes to evaluate the design effectiveness of the controls identified to mitigate the risk of material misstatements occurring in our financial statements. We have also initiated a detailed process to evaluate the operating effectiveness of our controls over financial reporting. This process involves testing the controls for effectiveness, including a review and inspection of the documentary evidence supporting the operation of the controls on which we are placing reliance.

As a result of our efforts to ensure compliance with Section 404 of SOX, we have also become aware of deficiencies in our internal controls over financial reporting in other areas of the company. The deficiencies we have identified include inadequate change management and security access to our information systems, lack of segregation of duties related to manual journal entry preparation and procurement activities, lack of formal documentation of policies and procedures, informal evidence to substantiate monitoring activities were adequately performed, inadequate staffing to provide effective monitoring of complex processes, such as derivative valuations and untimely preparation and review of volume and account reconciliations. Although we have not formally assessed the materiality of each deficiency identified, we believe that the deficiencies in the aggregate constitute a material weakness in our internal controls.

We are actively remediating these deficiencies and have already implemented our action plans for the following:

- Developing and implementing standard information system policies to govern change management and security access to our information systems across the company;
- Modifying systems and procedures to ensure appropriate segregation of responsibilities for manual journal entry preparation;
- Formalizing our account reconciliation policy and timely completing all material account reconciliations; and

- Developing and implementing formal training to educate company personnel on management's responsibilities mandated by SOX Section 404, the components of the internal control framework on which we rely and the relationship to our company values including accountability, stewardship, integrity and excellence.

We are in the process of implementing the following action plans and expect to have them fully implemented by December 31, 2004:

- Modifying systems and/or procedures to ensure appropriate segregation of responsibilities for procurement activities;
- Implementing an account reconciliation tool to facilitate the monitoring of compliance with our account reconciliation policy;
- Evaluating, formalizing and communicating required policies and procedures;
- Implementing appropriate monitoring activities to ensure compliance with the company's policies and procedures; and
- Reviewing the finance and accounting staffing.

Many of the deficiencies in our internal controls that we have identified are likely the result of significant changes the company has undergone during the past five years as a result of major acquisitions and reorganizations. We currently have company-wide efforts underway to formalize and improve our internal controls and effectively remediate all of the deficiencies described above. We have also performed additional analysis and procedures related to the deficiencies identified and have concluded that the deficiencies have not resulted in any material errors in these financial statements. As we continue our SOX Section 404 compliance efforts, including the testing of the effectiveness of our internal controls, we may identify additional deficiencies in our system of internal controls over financial reporting that either individually or in the aggregate may represent a material weakness requiring additional remediation efforts. We did not make any changes to our internal controls over financial reporting during the quarter ended December 31, 2003, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. However, as we discussed above, since December 31, 2003, we have made significant changes to our internal controls.

We have communicated to our Audit Committee and to our external auditors the deficiencies identified to date in our internal controls over financial reporting as well as the remediation efforts that we have underway. Our management, with the oversight of our Audit Committee, is committed to effectively remediating known deficiencies as expeditiously as possible and continuing its extensive efforts to comply with Section 404 of SOX by December 31, 2004.

We undertook, in a separate evaluation under the supervision of our principal executive and principal financial officers, and with the participation of other members of our management, a review of our disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. As a result of the deficiencies and material weaknesses identified above, we concluded that our disclosure controls and procedures were ineffective as of December 31, 2003. To address the deficiencies and material weaknesses described above, we significantly expanded our disclosure controls and procedures to include additional analysis and other post-closing procedures to ensure our disclosure controls and procedures were effective over the preparation of these financial statements.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 16, 2004, regarding our executive officers and directors. Directors are elected annually and hold office until their successors are elected and duly qualified. Each executive officer has been elected to serve until his successor is duly appointed or elected or until his earlier removal or resignation from office. Information regarding our executive officers may be found in Part I, Item I, Business, and is incorporated herein by reference.

There are no family relationships among any of our executive officers or directors, and, unless described herein, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer or a director.

Name	Age	Position
John M. Bissell	73	Director
Juan Carlos Braniff	47	Director
James L. Dunlap	67	Director
Douglas L. Foshee	45	Director; President and Chief Executive Officer
Robert W. Goldman	62	Director
Anthony Hall	60	Director
Thomas R. Hix	57	Director
William H. Joyce	68	Director
Ronald L. Kuehn, Jr.	69	Director; Chairman of the Board
J. Carleton MacNeil, Jr.	70	Director
J. Michael Talbert	57	Director
Malcolm Wallop	71	Director
John L. Whitmire	63	Director
Joe B. Wyatt	69	Director

Mr. Bissell served as Lead Director of El Paso from March 2003 to December 2003. Mr. Bissell served as a director of The Coastal Corporation from 1985 to January 2001. During the past five years, Mr. Bissell has been the Chairman of the Board of BISSELL Inc., and he has served in various executive capacities at BISSELL Inc. since 1966. Mr. Bissell served as a director of American Natural Resources Company, parent holding company of ANR Pipeline Company, from May 1983 to June 1996, at which time there was a reduction in the number of directors and he did not stand for re-election. Mr. Bissell is a member of the Audit Committee and Compensation Committee.

Mr. Braniff has been a business consultant since January 2004. He served as Vice Chairman of Grupo Financiero BBVA Bancomer from October 1999 to January 2004, as Deputy Chief Executive Officer of Retail Banking from September 1994 to October 1999 and as Executive Vice President of Capital Investments and Mortgage Banking from December 1991 to September 1994. Mr. Braniff is Chairman of the Audit Committee and a member of the Finance Committee.

Mr. Dunlap's primary occupation has been as a business consultant since 1999. He served as Vice Chairman, President and Chief Operating Officer of Ocean Energy/United Meridian Corporation from 1996 to 1999. He was responsible for exploration and production and the development of the international exploration business. For 33 years prior to that date, Mr. Dunlap served Texaco, Inc. in various positions, including Senior Vice President, President of Texaco USA, President and Chief Executive Officer of Texaco Canada Inc. and Vice Chairman of Texaco Ltd., London. Mr. Dunlap is currently a member of the board of directors of Massachusetts Mutual Life Insurance Company and a member of Nantucket Conservation Foundation, the Culver Educational Foundation and the Corporation of the Woods Hole Oceanographic Institution. Mr. Dunlap is a member of the Compensation Committee and Governance Committee.

Mr. Foshee has been President, Chief Executive Officer and a director of El Paso since September 2003. He 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 will jointly resolve their asbestos claims. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer, and Chairman of the Board of 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.

Mr. Goldman's primary occupation has been as a business consultant since October 2002. He served as Senior Vice President, Finance and Chief Financial Officer of Conoco Inc. from 1998 to 2002 and Vice President, Finance from 1991 to 1998. For more than five years prior to that date, he held various executive positions with Conoco Inc. and E.I. Du Pont de Nemours & Co., Inc. Mr. Goldman was also formerly Vice President and Controller of Conoco Inc. and Chairman of the Accounting Committee of the American Petroleum Institute. He is currently Vice President, Finance of the World Petroleum Congress and a member of the board of directors of Tesoro Petroleum Corporation. Mr. Goldman is Chairman of the Finance Committee and a member of the Audit Committee.

Mr. Hall has been Chief Administrative Officer of the City of Houston since January 2004. He served as the City Attorney for the City of Houston from March 1998 to January 2004. He served as a director of The Coastal Corporation from August 1999 to January 2001. Prior to March 1998, Mr. Hall was a partner in the Houston law firm of Jackson Walker, LLP. Mr. Hall is Co-Chairman of the Governance Committee and a member of the Finance Committee and Health, Safety & Environmental Committee.

Mr. Hix has been a business consultant since January 2003. He served as Senior Vice President of Finance and Chief Financial Officer of Cooper Cameron Corporation from January 1995 to January 2003. From September 1993 to April 1995, Mr. Hix served as Senior Vice President of Finance, Treasurer and Chief Financial Officer of The Western Company of North America. Mr. Hix is a member of the board of directors of The Offshore Drilling Company. Mr. Hix is a member of the Audit Committee and Finance Committee.

Dr. Joyce has been Chairman of the Board and Chief Executive Officer of Nalco Company since November 2003. From May 2001 to October 2003, he served as Chief Executive Officer of Hercules Inc. In 2001, Dr. Joyce served as Vice Chairman of the Board of Dow Chemical Corporation following its merger with Union Carbide Corporation. Dr. Joyce was named Chief Executive Officer of Union Carbide Corporation in 1995 and Chairman of the Board in 1996. Prior to 1995, Dr. Joyce served in various positions with Union Carbide. Dr. Joyce is a director of CVS Corporation. Dr. Joyce is a member of the Governance Committee and Health, Safety & Environmental Committee.

Mr. Kuehn is currently the Chairman of the El Paso Board. Mr. Kuehn was Chairman of the Board and Chief Executive Officer from March 2003 to September 2003. From September 2002 to March 2003, Mr. Kuehn was the Lead Director of El Paso. From January 2001 to March 2003, he was a business consultant. Mr. Kuehn served as non-executive Chairman of the Board of El Paso from October 25, 1999 to December 31, 2000. Mr. Kuehn served as President and Chief Executive Officer of Sonat Inc. from June 1984 until his retirement on October 25, 1999. He was Chairman of the Board of Sonat Inc. from April 1986 until his retirement. He is a director of AmSouth Bancorporation, Praxair, Inc. and The Dun & Bradstreet Corporation. Mr. Kuehn resigned his position as a director and a member of the compensation committee of Transocean Inc. in March 2003 when Mr. Talbert joined the El Paso Board.

Mr. MacNeil served as a director of The Coastal Corporation from 1997 until January 2001. During the past five years, Mr. MacNeil's occupation has been securities brokerage and investments. Mr. MacNeil served as a director of American Natural Resources Company, parent holding company of ANR Pipeline Company from August 1993 until June 1996, at which time there was a reduction in the number of directors and he did not stand for re-election. Mr. MacNeil is a member of the Audit Committee and Governance Committee.

Mr. Talbert has been Chairman of the Board of Transocean Inc. since October 2002. He served as Chief Executive Officer of Transocean Inc. and its predecessor companies from 1994 until October 2002, and has been a member of its board of directors since 1994. Mr. Talbert is also the Chairman of the Board of The Offshore Drilling Company. He served as President and Chief Executive Officer of Lone Star Gas Company from 1990 to 1994. He served as President of Texas Oil & Gas Company from 1987 to 1990, and served in various positions at Shell Oil Company from 1970 to 1982. Mr. Talbert is a past Chairman of the National Ocean Industries Association and a member of the University of Akron's College of Engineering Advancement Council. Mr. Talbert is a member of the Compensation Committee, Finance Committee and Health, Safety and Environmental Committee.

Mr. Wallop became Chairman of Western Strategy Group in January 1999 and has been President of Frontiers of Freedom Foundation since January 1996. For 18 years prior to that date, Mr. Wallop was a member of the United States Senate. He is a member of the board of directors of Hubbell Inc. and Sheridan State Bank. Mr. Wallop is Co-Chairman of the Governance Committee and a member of the Audit Committee.

Mr. Whitmire has been Chairman of CONSOL Energy, Inc. since 1999. He served as Chairman and CEO of Union Texas Petroleum Holdings, Inc. from 1996 to 1998, and spent over 30 years serving Phillips Petroleum Company in various positions including Executive Vice President of Worldwide Exploration and Production from 1992 to 1996 and Vice President of North American Exploration and Production from 1988 to 1992. He also served as a member of the Phillips Petroleum Company Board of Directors from 1994 to 1996. He is a member of the board of directors of GlobalSantaFe Inc. Mr. Whitmire is Chairman of the Health, Safety and Environmental Committee and a member of the Audit Committee and Compensation Committee.

Mr. Wyatt has been Chancellor Emeritus of Vanderbilt University since August 2000. For more than five years prior to that date, he served as Chancellor, Chief Executive Officer and Trustee of Vanderbilt University. From 1984 until October 1999, Mr. Wyatt was a director of Sonat Inc. He is a director of Ingram Micro, Inc. and Hercules, Inc. Mr. Wyatt is Chairman of the Compensation Committee and a member of the Governance Committee.

Audit Committee Financial Expert. The Audit Committee plays an important role in promoting effective corporate governance, and it is imperative that members of the Audit Committee have requisite financial literacy and expertise. All members of El Paso's Audit Committee meet the financial literacy standard required by the NYSE rules and at least one member qualifies as having accounting or related financial management expertise under the NYSE rules. In addition, as required by SOX, the SEC adopted rules requiring that each public company disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, satisfies all of the following attributes:

- An understanding of generally accepted accounting principles and financial statements.
- An ability to assess the general application of such principles in connection with the accounting for estimates, accruals, and reserves.
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of issues that can reasonably be expected to be raised by El Paso's financial statements, or experience actively supervising one or more persons engaged in such activities.
- An understanding of internal controls and procedures for financial reporting.
- An understanding of audit committee functions.

The Board of Directors has affirmatively determined that Messrs. Hix and Goldman satisfy the definition of "audit committee financial expert," and has designated each of them as an "audit committee financial expert."

Section 16(a) Beneficial Ownership Reporting Compliance. Section 16(a) of the Exchange Act requires our directors, certain officers and beneficial owners of more than 10% of a registered class of our equity securities to file reports of ownership and reports of changes in ownership with the SEC and the New York Stock Exchange. Directors, officers and beneficial owners of more than 10% of our equity securities are also required by SEC regulations to furnish us with copies of all such reports that they file. Based on our review of copies of such forms and amendments provided to it, we believe that all filing requirements were complied with during the fiscal year ended December 31, 2003.

Code of Ethics. We have adopted a code of ethics, the "Code of Business Conduct," that applies to all of our directors and employees, including our Chief Executive Officer, Chief Financial Officer and senior financial and accounting officers. In addition to other matters, the Code of Business Conduct establishes policies to deter wrongdoing and to promote honest and ethical conduct, including ethical handling of actual or apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the Code of Business Conduct. We also have an Ethics & Compliance Office and Ethics & Compliance Committee, composed of members of senior management, that administers our ethics and compliance program. A copy of our Code of Business Conduct is available on our website at *www.elpaso.com*. We will post on our internet website all waivers to or amendments of our Code of Business Conduct, which are required to be disclosed by applicable law and rules of the NYSE listing standards.

As a result of recent clarifications in the insider trading rules, and in particular, the promulgation of Rule 10b5-1, we have revised our insider trading policy to 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 September 20, 2004, 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

Compensation of Executive Officers. This table and narrative text discusses the compensation paid in 2003, 2002 and 2001 to our Chief Executive Officer and our four other most highly compensated executive officers. In addition, as required by SEC rules, we have provided the compensation information for Messrs. Kuehn and Wise who each served as our CEO during 2003. The compensation reflected for each individual was for their services provided in all capacities to El Paso and its subsidiaries. This table also identifies the principal capacity in which each of the executives named in this Annual Report on Form 10-K served El Paso at the end of fiscal year 2003.

Summary Compensation Table

					Long-Term Compensation			
		Annual Compensation			Awards		Payouts	
Name and Principal Position	Year	Salary ($)[1]	Bonus ($)[2]	Other Annual Compensation ($)[3]	Restricted Stock Awards ($)[4]	Securities Underlying Options (#)	Long-Term Incentive Plan Payouts ($)[5]	All Other Compensation ($)[6]
Douglas L. Foshee[7]	2003	$ 297,115	$ 600,000	—	—	1,000,000	—	$ 1,758,913
President and Chief Executive Officer								
John W. Somerhalder II	2003	$ 617,500	$ 750,000	—	$ —	—	$ 215,850	$ 14,250
Executive Vice	2002	$ 600,000	$ —	—	$ —	—	—	$ 81,926
President	2001	$ 552,091	$1,140,000	—	$ 569,992	223,000	—	$ 946,591
D. Dwight Scott	2003	$ 517,504	$ 750,000	—	$ —	—	—	$ 511,775
Executive Vice	2002	$ 387,504	$ —	—	$ —	—	—	$ 71,108
President and Chief Financial Officer	2001	$ 252,091	$ 360,039	—	$ 179,961	137,000	—	$ 59,628
Robert G. Phillips	2003	$ 459,178	$ 750,000	—	$ —	—	$ 215,850	$ 2,813
President, El Paso	2002	$ 400,008	$ —	$ 43,773	$ —	—	—	$ 37,921
Field Services	2001	$ 376,042	$ 560,000	—	$ 279,958	151,250	—	$ 912,039
Robert W. Baker	2003	$ 360,837	$ 350,000	—	$ —	—	—	$ 10,500
Executive Vice	2002	$ 250,008	$ 50,000	$ 36,000	$ —	—	—	$ 21,857
President	2001	$ 230,838	$ 200,006	—	$ 99,994	101,375	—	$ 720,407
Ronald L. Kuehn, Jr.[8]	2003	$ 568,462	$ 600,000	—	$ 247,500	125,000	—	$ 1,748,825
Former Chief Executive Officer								
William A. Wise[9]	2003	$ 297,918	$ —	$ 37,434	$ —	—	$2,166,750	$15,486,077
Former Chief	2002	$1,430,004	$ —	$229,728	$ —	—	—	$ 255,632
Executive Officer	2001	$1,305,425	$3,432,000	$210,481	$1,715,997	768,250	—	$ 3,771,994

(1) The amount reflected in the salary column for 2003 and 2002 for Messrs. Somerhalder, Phillips, Baker and Wise includes an amount for El Paso mandated reductions to fund certain charitable organizations.

(2) For fiscal year 2001, El Paso's incentive compensation plans required executives to receive a substantial part of their annual bonus in shares of restricted El Paso common stock. The amounts reflected in this column for 2001 represent a combination of the market value of the restricted stock and cash at the time awarded under the applicable El Paso incentive compensation plan.

(3) The amount reflected for Mr. Phillips in fiscal year 2002 includes, among other things, $42,000 for a perquisite and benefit allowance. The amount reflected for Mr. Baker in fiscal year 2002 is a $36,000 perquisite and benefit allowance. The amount reflected for Mr. Wise in fiscal year 2003 includes, among other things, $18,750 for a perquisite and benefit allowance and $9,638 in value attributed to use of El Paso's aircraft. The amount reflected for Mr. Wise in fiscal year 2002 includes, among other things, $90,000 for a perquisite and benefit allowance and $65,509 in value attributed to use of El Paso's aircraft. The amount reflected for Mr. Wise in 2001 includes, among other things, $90,000 for a perquisite and benefit allowance and $62,692 in value attributed to use of El Paso's aircraft. Except as noted, the total value of the perquisites and other personal benefits received by the other executives named in this Annual Report on Form 10-K in fiscal years 2003, 2002 and 2001 are not included in this column since they were below the Securities and Exchange Commission's reporting threshold.

(4) For fiscal year 2003, Mr. Kuehn received a grant of 50,000 shares of restricted stock in connection with assumption of the interim CEO position, the grant date value of which is reflected in this column. For fiscal year 2001, El Paso's incentive compensation plans provided for and encouraged participants to elect to take the cash portion of their annual bonus award in shares of restricted stock. The amounts reflected in this column for 2001 include the market value of restricted stock on the date of grant. The value of the

shares of common stock issued has declined significantly since the date of grant. The total number of shares and value of restricted stock (including the amount in this column) held on December 31, 2003, is as follows:

Restricted Stock as of December 31, 2003

Name	Total Number of Restricted Stock (#)	Value of Restricted Stock ($)
Douglas L. Foshee	200,000	$1,638,000
John W. Somerhalder II	124,596	$1,020,441
D. Dwight Scott	58,444	$ 478,656
Robert G. Phillips	81,706	$ 669,172
Robert W. Baker	51,275	$ 419,942
Ronald L. Kuehn, Jr.	—	$ —
William A. Wise	—	$ —

With the exception of Messrs. Foshee's and Kuehn's grants, most of these shares of El Paso's restricted stock are subject to a time-vesting schedule of four years from the date of grant (including the shares awarded as part of the annual bonus in 2001 described above) and other shares of restricted stock which are subject to both time-vesting and performance-vesting. With respect to performance vesting, if the required El Paso performance targets are not met within a four-year time period, all unvested shares are forfeited. Any dividends awarded on the restricted stock are paid directly to the holder of the El Paso common stock. These total values can be realized only if the executives named in this Annual Report on Form 10-K remain employees of El Paso for the required period of years and, with respect to performance vesting, the performance goals regarding stockholder value are reached.

(5) For fiscal year 2003, the amount reflected in this column is the value of shares of restricted stock on the date they vested. These shares had been reported in a long-term incentive table in El Paso's proxy statement for the year in which those shares of restricted stock were originally granted, along with the necessary performance measures for their vesting. No long-term incentive payouts were made in fiscal years 2002 and 2001.

(6) The compensation reflected in this column for fiscal year 2003 includes El Paso's contributions to the El Paso Retirement Savings Plan and supplemental company match for the Retirement Savings Plan under the Supplemental Benefits Plan, as follows:

El Paso's Contributions to the Retirement Savings Plan and Supplemental Company Match under the Supplemental Benefits Plan for Fiscal Year 2003

Name	Retirement Savings Plan ($)	Supplemental Benefits Plan ($)
Douglas L. Foshee	$6,000	$2,913
John W. Somerhalder II	$4,425	$9,825
D. Dwight Scott	$3,750	$8,025
Robert G. Phillips	$2,438	$ 375
Robert W. Baker	$4,650	$5,850
Ronald L. Kuehn, Jr.	$ —	$ —
William A. Wise	$9,000	$2,850

In addition, for fiscal year 2003 for Mr. Foshee, the amount in this column includes the value of a sign-on bonus in the amount of $875,000 in cash and $875,000 in common stock. In addition, for fiscal year 2003 for Mr. Scott, the amount in this column includes the value of a special retention payment in the amount $500,000. In addition, for fiscal year 2003 for Mr. Kuehn, the amount in this column includes $881,588 for the value of the split-dollar life insurance policy transferred to him in January 2003, $619,723 for the tax gross-up associated with the transfer of the split-dollar life insurance policy, $100,000 in severance attributed to him ceasing as interim CEO of El Paso and non-employee director fees received during 2003. In addition, for fiscal year 2003 for Mr. Wise, the amount in this column includes $15,474,227 ($15,326,532 of which includes his supplemental pension benefit earned during his employment) paid in connection with his termination.

(7) Mr. Foshee began his employment with El Paso on September 1, 2003.

(8) Mr. Kuehn served as interim CEO from March 13, 2003 to September 1, 2003.

(9) Mr. Wise ceased to be CEO on March 12, 2003. See Item 11, Executive Compensation for a description of Mr. Wise's employment agreement and the severance benefits he received pursuant to his employment agreement.

Stock Option Grants

This table sets forth the number of stock options granted at fair market value to the executives named in this Annual Report on Form 10-K during the fiscal year 2003. In satisfaction of applicable SEC regulations, the table further sets forth the potential realizable value of such stock options in the year 2013 (the expiration date of the stock options) at an assumed annualized rate of stock price appreciation of 5% and 10% over the full ten-year term of the stock options. As the table indicates for the grant made on September 2, 2003, annualized stock price appreciation of 5% and 10% would result in stock prices in the year 2013 of approximately $11.96 and $19.05, respectively. Further as the table indicates for the grant made on March 21, 2003, annualized stock price appreciation of 5% and 10% would result in stock prices in the year 2013 of approximately $10.64 and $16.95, respectively. The amounts shown in the table as potential realizable values for all stockholders' stock (approximately $2.9 billion and $7.4 billion for the September grant and approximately $2.6 billion and $6.6 billion for the March grant) represent the corresponding increases in the market value of 633,912,031 shares of the common stock outstanding as of December 31, 2003. No gain to the executive named in this Annual Report on Form 10-K is possible without an increase in stock price, which would benefit all stockholders. Actual gains, if any, on stock option exercises and common stock holdings are dependent on the future performance of the common stock and overall stock market conditions. There can be no assurances that the potential realizable values shown in this table will be achieved.

Option Grants in 2003

	Individual Grants[1]				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
					If Stock Price at $11.96423 and $10.64483 in 2013	If Stock Price at $19.05104 and $16.95011 in 2013
Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to all Employees in 2003	Exercise Price ($/Share)	Expiration Date	5% ($)	10% ($)
Potential Value of all Common Stock Outstanding on December 31, 2003						
September 2, 2003 Grant	**N/A**	**N/A**	**N/A**	**N/A**	**$2,928,186,126**	**$7,420,598,558**
March 21, 2003 Grant	**N/A**	**N/A**	**N/A**	**N/A**	**$2,605,268,391**	**$6,602,261,617**
Douglas L. Foshee	1,000,000	88.82%	$7.34500	9/2/2013	$ 4,619,231	$ 11,706,038
Ronald L. Kuehn, Jr.	125,000	11.10%	$6.53500	3/21/2003	$ 513,728	$ 1,301,888

(1) The stock options granted in 2003 to Mr. Foshee vest 20% per year over a five-year period from the date of grant. The stock options granted in 2003 to Mr. Kuehn vested in September 2003 when he ceased to be El Paso's interim CEO. No stock options were granted to any other of the named executives. There were no stock appreciation rights granted in 2003. Any unvested stock options become fully exercisable in the event of a "change in control." See Item 11, Executive Compensation of this Form 10-K for a description of El Paso's 2001 Omnibus Incentive Compensation Plan and the definition of the term "change in control." Under the terms of El Paso's 2001 Omnibus Incentive Compensation Plan, the Compensation Committee may, in its sole discretion and at any time, change the vesting of the stock options. Certain non-qualified stock options may be transferred to immediate family members, directly or indirectly or by means of a trust, corporate entity or partnership. Further, stock options are subject to forfeiture and/or time limitations on exercise in the event of termination of employment.

Option Exercises and Year-End Value Table

This table sets forth information concerning stock option exercises and the fiscal year-end values of the unexercised stock options, provided on an aggregate basis, for each of the executives named in this Annual Report on Form 10-K.

Aggregated Option Exercises in 2003
and Fiscal Year-End Option Values

Name	Shares Acquired on Exercise (#)[1]	Value Realized ($)[1]	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)[2]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Douglas L. Foshee	—	$ —	—	1,000,000	$ —	$860,000
John W. Somerhalder II	25,000	$179,875	430,383	41,667	$ —	$ —
D. Dwight Scott	—	$ —	115,247	28,247	$ —	$ —
Robert G. Phillips	25,000	$179,875	270,167	33,333	$ —	$ —
Robert W. Baker	—	$ —	176,709	18,333	$ —	$ —
Ronald L. Kuehn, Jr.	—	$ —	614,300	—	$208,750	$ —
William A. Wise	100,000	$719,500	1,787,917[3]	—	$ —	$ —

(1) The amounts in these columns represent the number of shares and the value realized upon conversion of stock options into shares of stock that occurred during 2003 based upon the achievement of certain performance targets established when they were originally granted in 1999.

(2) The figures presented in these columns have been calculated based upon the difference between $8.205, the fair market value of the common stock on December 31, 2003, for each in-the-money stock option, and its exercise price. No cash is realized until the shares received upon exercise of an option are sold. No executives named in this Annual Report on Form 10-K had stock appreciation rights that were outstanding on December 31, 2003.

(3) Includes 98,000 stock options held by the William & Marie Wise Family Ltd. Partnership.

Long-Term Incentive Awards

Restricted Stock

This table provides information concerning incentive awards of restricted common stock made under El Paso's 2001 Omnibus Incentive Compensation Plan. The number of shares of restricted stock will vest if, and only if, the executive named below remains in the employ of El Paso for the specified time period and the required increase in total stockholder return is achieved during such time period. No other named executive received a long-term incentive restricted stock award during 2003.

Long-Term Incentive Plans — Awards In 2003
Restricted Stock

Name	Number of Shares	Performance or Other Period Until Maturation	Estimated Number of Shares to be Vested Under Restricted Stock Grants			
			Below Threshold (#)	Threshold (#)	Target (#)	Maximum (#)
Douglas L. Foshee	200,000	5 years	—[1]	100,000	200,000	300,000[2]
Robert W. Baker	4,983	2 years	—	1,495	2,990	4,983

(1) El Paso's Compensation Committee has sole discretion with respect to the amount, if any, of shares that will vest.

(2) If El Paso's stock price performance is in the second quartile (50th to 74th percentile) relative to its peers, then the amount of shares that will vest will be pro-rata based upon actual placement relative to the peers.

Performance Units

This table provides information concerning long-term incentive awards of performance units under El Paso's 2001 Omnibus Incentive Compensation Plan. The grant reflected vested on June 30, 2003, at the end of the indicated maturation performance period, at which time El Paso's total stockholder return was compared to that of its peer group. With respect to the grant, if El Paso's total stockholder return ranked in the first, second, third or fourth quartiles of its peer group, the value of each unit would have been $150, $100, $50 and $0 respectively. The same performance thresholds and vesting date were applicable for all other outstanding awards of performance units under El Paso's 2001 Omnibus Incentive Compensation Plan and

1999 Omnibus Incentive Compensation Plan. The amounts reflected in the table are potential assumed amounts, and would have been payable in cash. No other named executive received any performance units during 2003. As described in the Compensation Committee Report on Executive Compensation, all outstanding performance units (including those identified in the table below) vested during 2003 at the "Below Threshold" level and the Compensation Committee determined no payments would be made under the performance unit plan.

Long-Term Incentive Plans — Awards In 2003
Performance Units

			Estimated Payouts Under Non-Stock Price Based Plans			
Name	Number of Shares	Performance or Other Period Until Maturation	Below Threshold (#)	Threshold ($)	Target ($)	Maximum ($)
Robert W. Baker	681	5 months	$—	$34,050	$68,100	$102,150

PENSION PLAN

Effective January 1, 1997, El Paso amended its pension plan to provide pension benefits under a cash balance plan formula that defines participant benefits in terms of a hypothetical account balance. Prior to adopting a cash balance plan, El Paso provided pension benefits under a plan (the "Prior Plan") that defined monthly benefits based on final average earnings and years of service. Under the cash balance plan, an initial account balance was established for each El Paso employee who was a participant in the Prior Plan on December 31, 1996. The initial account balance was equal to the present value of Prior Plan benefits as of December 31, 1996.

At the end of each calendar quarter, participant account balances are increased by an interest credit based on 5-Year Treasury bond yields, subject to a minimum interest credit of 4% per year, plus a pay credit equal to a percentage of salary and bonus. The pay credit percentage is based on the sum of age plus service at the end of the prior calendar year according to the following schedule:

Age Plus Service	Pay Credit Percentage
Less than 35	4%
35 to 49	5%
50 to 64	6%
65 and over	7%

Under El Paso's pension plan and applicable Internal Revenue Code provisions, compensation in excess of $200,000 cannot be taken into account and the maximum payable benefit in 2003 was $160,000. Any excess benefits otherwise accruing under El Paso's pension plan are payable under El Paso's Supplemental Benefits Plan. Participants will receive benefits in the form of a lump sum payment under the Supplemental Benefits Plan unless a valid irrevocable election was made to receive payment in a form other than lump sum prior to June 1, 2004.

Participants with an initial account balance on January 1, 1997 are provided minimum benefits equal to the Prior Plan benefit accrued as of the end of 2001. Upon retirement, certain participants (which include Messrs. Somerhalder, Phillips and Wise) are provided pension benefits that equal the greater of the cash balance formula benefit or the Prior Plan benefit. For Messrs. Somerhalder, Phillips and Wise, the Prior Plan benefit reflects accruals through the end of 2001 and is computed as follows: for each year of credited service up to a total of 30 years, 1.1% of the first $26,800, plus 1.6% of the excess over $26,800, of the participant's average annual earnings during his five years of highest earnings.

Credited service as of December 31, 2001, for each of Messrs. Somerhalder, Phillips and Wise is reflected in the table below. Amounts reported under Salary and Bonus for each executive named in the Summary Compensation Table approximate earnings as defined under the pension plan.

Estimated annual benefits payable from the pension plan and Supplemental Benefits Plan upon retirement at the normal retirement age (age 65) for each executive named is reflected below (based on assumptions that each named executive receives base salary shown in the Summary Compensation Table with no pay increases, receives 50% of target annual bonuses beginning with bonuses earned for fiscal year 2004, and cash balances are credited with interest at a rate of 4% per annum):

Named Executive	Credited Service[(1)]	Pay Credit Percentage During 2003	Estimated Annual Benefits[(2)]
Doug Foshee	N/A	5%	$250,683
John W. Somerhalder II	24	7%	$398,400
Dwight Scott	N/A	5%	$198,568
Robert G. Phillips	6	6%	$170,122
Robert Baker	N/A	7%	$111,496
Ronald Kuehn[(3)]	N/A	7%	$ 78,093
William A. Wise[(4)]	30	7%	$881,725

(1) For Messrs. Somerhalder, Phillips and Wise, credited service shown is as of December 31, 2001.

(2) For Mr. Wise, the amount reflected has been reduced as a result of his participation in the Alternative Benefits Program, as described in Item 11, Executive Compensation of this Form 10-K. Prior Plan minimum benefits for Messrs. Somerhalder and Wise are greater than their projected cash balance benefits at age 65.

(3) The amount reflected for Mr. Kuehn is his vested pension benefit amount under both the Supplemental Benefits Plan and the tax-qualified pension plan as of his termination date of September 2, 2003, payable commencing October 1, 2003 (at age 68). Mr. Kuehn has elected to receive his Supplemental Benefits Plan benefit in a lump sum of $79,211, minus amounts withheld for taxes. Mr. Kuehn has also elected to receive his benefit under the tax-qualified pension plan in a lump sum of $15,834. Additionally, due to Mr. Kuehn's previous employment with Sonat Inc., he is also receiving an annual benefit (75% joint and survivor form of payment) under the tax-qualified pension plan equal to $69,309.

(4) The amount reflected for Mr. Wise is his vested pension benefit amount under both the Supplemental Benefits Plan and the tax-qualified pension plan as of his termination date of March 12, 2003, payable commencing at age 65. Mr. Wise has elected to receive his Supplemental Benefits Plan benefit in a lump sum of $15,326,532, minus amounts withheld for taxes. Mr. Wise elected to receive a single life annuity benefit under the tax-qualified pension plan equal to $97,520 annually.

EMPLOYMENT CONTRACTS, TERMINATION OF EMPLOYMENT, CHANGE IN CONTROL ARRANGEMENTS AND DIRECTOR INDEMNIFICATION AGREEMENTS

Employment Agreements

Current Employees

Douglas L. Foshee entered into a letter agreement with El Paso effective September 1, 2003. Under this agreement, Mr. Foshee serves as President, Chief Executive Officer and a director of El Paso and receives an annual salary of $900,000 (which Mr. Foshee has voluntarily reduced for 2004 to $630,000). Mr. Foshee is also eligible to earn a target bonus amount equal to 100% of his annual salary (a maximum bonus of 200% of salary) based on El Paso's and his performance as determined by the Compensation Committee. Mr. Foshee will receive the additional employee benefits which are available to senior executive officers. In addition, on the start date of his employment, Mr. Foshee was granted 1,000,000 options to purchase El Paso common stock and 200,000 shares of restricted stock. The options will time vest pro-rata over a five-year period. The shares of restricted stock have both time and performance vesting provisions. Depending on El Paso's performance relative to its peers during the first year, the number of shares Mr. Foshee may actually receive is between zero and 300,000 shares. The shares of restricted stock that vest based on performance also time vest pro-rata over a five-year period. On his start date, Mr. Foshee received common stock with a value of $875,000 and an additional cash payment of $875,000. Mr. Foshee may not pledge or sell the common stock received as part of the sign-on bonus for a period of two years from the grant date. If Mr. Foshee's employment is involuntarily terminated not for cause, Mr. Foshee will receive a lump sum payment of two years base pay and target bonus. In the event he is terminated within two years of a change in control (or terminates employment for good reason), Mr. Foshee will receive a lump sum payment of three years annual salary and target bonus (plus a pro-rated portion of his target bonus).

Former Employees

As part of the merger with Sonat, El Paso entered into a termination and consulting agreement with Ronald L. Kuehn, Jr., dated October 25, 1999. Under this agreement, Mr. Kuehn served as the non-executive Chairman of El Paso's Board of Directors through December 31, 2000, and received a fee of $20,833 per month from October 25, 1999 through December 31, 2000. In addition, Mr. Kuehn received the perquisites that were available to him prior to the merger with Sonat pursuant to this agreement, as well as non-cash compensation available to other non-employee directors. Starting on October 25, 1999, and for the remainder of his life, Mr. Kuehn will receive certain ancillary benefits made available to him prior to the merger with Sonat, including the provision of office space and related services, and payment of life insurance premiums sufficient to provide a death benefit equal to four times his base pay as in effect immediately prior to October 25, 1999. Mr. Kuehn and his eligible dependents will also receive retiree medical coverage. El Paso maintained a collateral assignment split-dollar life insurance policy to provide for the death benefit for Mr. Kuehn to satisfy its obligation to provide the life insurance referenced above. In January 2003, El Paso released the collateral assignment on the policy. El Paso recovered $1,116,303 from the policy's cash surrender value for premiums paid by El Paso and its predecessors for Mr. Kuehn under the policy and gave up the right to recoup $881,588, which was left in the policy to provide coverage under the policy until age 95. The release of the collateral assignment and the right to recoup $881,588 was treated as a transfer of property to Mr. Kuehn subject to ordinary income tax. El Paso paid Mr. Kuehn $619,723 to satisfy the tax liabilities related to the transfer of the policy. In March 2003, Mr. Kuehn, in an interim capacity, replaced Mr. Wise as Chief Executive Officer of El Paso. At that time, El Paso entered into an employment agreement with Mr. Kuehn effective upon his appointment as interim Chief Executive Officer of El Paso. Mr. Kuehn has also served as Chairman of the Board of El Paso since March 2003. Under his employment agreement, Mr. Kuehn received a monthly salary of $100,000 and was eligible to earn a target bonus amount equal to 100% of his annual salary based on El Paso's and his performance as determined by the Compensation Committee. Pursuant to his employment agreement, on the date Mr. Foshee began as the permanent Chief Executive Officer of El Paso, Mr. Kuehn received a pro-rated portion of his target bonus based on the number of months he served as the interim Chief Executive Officer in the amount of $600,000 and a termination payment in the amount of $100,000 for the time he served as interim Chief Executive Officer. Mr. Kuehn's employment agreement also provided for an award of 125,000 nonqualified stock options to purchase shares of common stock and 50,000 shares of restricted stock of El Paso under the 2001 Omnibus Incentive Compensation Plan. His stock options vested and all restrictions on his restricted stock lapsed on the date Mr. Foshee began as the permanent Chief Executive Officer.

Effective as of March 12, 2003, Mr. Kuehn replaced William A. Wise as Chief Executive Officer and Chairman of the Board of Directors pending selection of a permanent Chief Executive Officer. Mr. Wise received the severance benefits set forth in his pre-existing employment agreement for the remaining three-year term of his agreement consisting of his annual salary of $1,430,004, an annual bonus in the amount of $1,716,004, service credit and age credit for pension benefits and continued medical, dental and vision insurance. Effective in May 2004, payment to Mr. Wise of his annual salary was suspended. In May 2004, Mr. Wise initiated an arbitration in connection with his employment agreement. Mr. Wise asserts that he is entitled to additional perquisites under the terms of his pre-existing employment agreement. Mr. Wise is not entitled to receive benefits under his employment agreement that otherwise would arise in connection with any future change in control of El Paso. Any salary, bonus, or benefits received by Mr. Wise in connection with any full-time employment during the remaining three-year term will reduce the salary, bonus, or benefits payable to Mr. Wise under the terms of his agreement. In March 2003, El Paso transferred ownership of Mr. Wise's company-owned automobile to Mr. Wise and agreed to purchase his Houston residence, if timely requested to do so, at the greater of its appraised value or the amount of Mr. Wise's investment. In 1997, El Paso loaned Mr. Wise $1,564,000 with interest at 6.8% for the purchase of his Houston residence. On March 19, 2003, Mr. Wise repaid this loan in full with accrued interest, consisting of $1,564,000 in principal and $617,436 in interest. In 2001, El Paso loaned Mr. Wise $7,332,195 with interest at 4.99% to fund Mr. Wise's exercise of options to purchase El Paso common stock. This outstanding loan obligation became payable by Mr. Wise in full upon the cessation of his employment. On April 23, 2003, Mr. Wise repaid this loan in full with accrued interest, consisting of $7,332,195 in principal and $594,549 in interest. In addition, Mr. Wise held 1,887,917 vested stock options. These options are exercisable by Mr. Wise through March 12, 2006, unless they expire earlier in accordance with their terms. Any portion of these options not exercised by March 12, 2006 or any earlier applicable expiration date will be forfeited on that date. Of these 1,887,917 stock options, 100,000 were converted automatically into shares of El Paso common stock on October 25, 2003, with the value per option equal to the fair market value of El Paso common stock on that date. Mr. Wise forfeited 258,333 unvested stock options when he ceased to be an employee of El Paso on March 12, 2003. In addition, 491,639 shares of restricted stock held by Mr. Wise on March 12, 2003 became vested as of that date, and 139,609 shares of restricted stock were forfeited as of that date. Mr. Wise also became vested in 33,281 performance units, the performance cycle for which ended in June 2003, without value, and he forfeited 2,219 unvested performance units.

Benefit Plans

Severance Pay Plan. The Severance Pay Plan is a broad-based employee plan providing severance benefits following a "qualifying termination" for all salaried employees of El Paso and certain of its subsidiaries. The plan also includes an executive supplement, which provides enhanced severance benefits for certain executive officers of El Paso and certain of its subsidiaries, including Messrs. Foshee, Somerhalder, Scott, Phillips and Baker. The enhanced severance benefits available under the supplement include an amount equal to two times the sum of the officer's annual salary, including annual target bonus amounts as specified in the plan. A qualifying termination includes an involuntary termination of the officer as a result of the elimination of the officer's position or a reduction in force and a termination for "good reason" (as defined under the plan). In the event the Severance Pay Plan is terminated, the executive supplement will continue as a separate plan unless the action terminating the Severance Pay Plan explicitly terminates the supplement. The executive supplement of the Severance Pay Plan terminates on January 1, 2005, unless extended. In the event of a "change in control" (as defined in the Key Executive Severance Protection Plan) of El Paso, participants whose termination of employment entitles them to severance pay under the executive supplement and the Key Executive Severance Protection Plan will receive severance pay under the Key Executive Severance Protection Plan, rather than under the executive supplement.

2004 Key Executive Severance Protection Plan. El Paso periodically reviews its benefits plans and engages Deloitte Consulting to make recommendations regarding its plans. Deloitte recommended that El Paso adopt a new executive severance plan that more closely aligns with current market arrangements than El Paso's Key Executive Severance Protection Plan and Employee Severance Protection Plan (as described below). In light of Deloitte's recommendation, El Paso adopted this plan in March 2004. This plan provides severance benefits following a "change in control" of El Paso for executives of El Paso and certain of its subsidiaries designated by the Board or the Compensation Committee, including Messrs. Foshee, Scott and Baker. This plan is intended to replace the Key Executive Severance Protection Plan and the Employee Severance Protection Plan, and participants are required to waive their participation under those plans (if applicable) as a condition to becoming participants in this plan. The benefits of the plan include: (1) a cash severance payment in an amount equal to three times the annual salary and target bonus for Mr. Foshee, two times the annual salary and target bonus for executive vice presidents and senior vice presidents, including Messrs. Scott and Baker, and one times the annual salary and target bonus for vice presidents; (2) a pro-rated portion of the executive's target bonus for the year in which the termination of employment occurs; (3) continuation of life and health insurance following termination for a period of 36 months for Mr. Foshee, 24 months for executive vice presidents and senior vice presidents, including Messrs. Scott and Baker, and 12 months for vice presidents; (4) a gross-up payment for any federal excise tax imposed on an executive in connection with any payment or distribution made by El Paso or any of its affiliates under the plan or otherwise; provided that in the event a reduction in payments in respect of the executive of 10% or less would cause no excise tax to be payable in respect of that executive, then the executive will not be entitled to a gross-up payment and payments to the executive shall be reduced to the extent necessary so that the payments shall not be subject to the excise tax; and (5) payment of legal fees and expenses incurred by the executive to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment of an executive in the plan within two years following the date of a change in control, except where termination is by reason of death, disability, for "cause" (as defined in the plan) or instituted by the executive other than for "good reason" (as defined in the plan). Benefits are also payable under the plan for terminations of employment prior to a change in control that arise in connection with, or in anticipation of, a change in control. Benefits are not payable for any termination of employment following a change in control if (i) the termination occurs in connection with the sale, divestiture or other disposition of designated subsidiaries of El Paso, (ii) the purchaser or entity subject to the transaction agrees to provide severance benefits at least equal to the benefits available under the plan, and (iii) the executive is offered, or accepts, employment with the purchaser or entity subject to the transaction. A change in control generally occurs if: (i) any person or entity becomes the beneficial owner of more than 20% of El Paso's common stock; (ii) a majority of the current members of the Board of Directors of El Paso or their approved successors cease to be directors of El Paso (or, in the event of a merger, the ultimate parent following the merger); or (iii) a merger, consolidation, or reorganization of El Paso, a complete liquidation or dissolution of El Paso, or the sale or disposition of all or substantially all of El Paso's and its subsidiaries' assets (other than a transaction in which the same stockholders of El Paso before the transaction own 50% of the outstanding common stock after the transaction is complete). This plan generally may be amended or terminated at any time prior to a change in control, provided that any amendment or termination that would adversely affect the benefits or protections of any executive under the plan shall be null and void as it relates to that executive if a change in control occurs within one year of the amendment or termination. In addition, any amendment or termination of the plan in connection with, or in anticipation of, a change in control which actually occurs shall be null and void. From and after a change in control, the plan may not be amended in any manner that would adversely affect the benefits or protections provided to any executive under the plan.

Key Executive Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a "change in control" of El Paso for certain officers of El Paso and certain of its subsidiaries, including Messrs. Somerhalder and Phillips. The benefits of the plan include: (1) an amount equal to three times the participant's annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination; (3) a supplemental pension payment calculated by adding three years of additional credited pension service; (4) certain additional payments to the terminated employee to cover excise taxes if the payments made under the plan are subject to excise taxes on golden parachute payments; and (5) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control, except where termination is by reason of death, disability, for cause or instituted by the employee for other than "good reason" (as defined in the plan). A change in control occurs if: (i) any person or entity becomes the beneficial owner of 20% or more of El Paso's common stock; (ii) any person or entity (other than El Paso) purchases the common stock by way of a tender or exchange offer; (iii) El Paso stockholders approve a merger or consolidation, sale or disposition or a plan of liquidation or dissolution of all or substantially all of El Paso's assets; or (iv) if over a two year period a majority of the members of the Board of Directors at the beginning of the period cease to be directors. A change in control has not occurred if El Paso is involved in a merger, consolidation or sale of assets in which the same stockholders of El Paso before the transaction own 80% of the outstanding common stock after the transaction is complete. This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan or be made following the occurrence of a change in control. This plan is closed to new participants, unless the Board determines otherwise.

Employee Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a "change in control" (as defined in the Key Executive Severance Protection Plan) of El Paso for certain salaried, non-executive employees of El Paso and certain of its subsidiaries. The benefits of the plan include: (1) severance pay based on the formula described below, up to a maximum of two times the participant's annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination (plus an additional payment, if necessary, equal to any additional income tax imposed on the participant by reason of his or her continued life and health insurance coverage); and (3) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. The formula by which severance pay is calculated under the plan consists of the sum of: (i) one-twelfth of a participant's annual salary and maximum bonus for every $7,000 of his or her annual salary and maximum bonus, but no less than five-twelfths nor more than the entire salary and bonus amount, and (ii) one-twelfth of a participant's annual salary and maximum bonus for every year of service performed immediately prior to a change in control. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control, except where termination is by reason of death, disability, for cause or instituted by the employee for other than "good reason" (as defined in the plan). This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan or be made following the occurrence of a change in control. This plan has been closed to new participants, unless the Board determines otherwise.

Supplemental Benefits Plan. This plan provides for certain benefits to officers and key management employees of El Paso and its subsidiaries. The benefits include: (1) a credit equal to the amount that a participant did not receive under El Paso's Pension Plan because the Pension Plan does not consider deferred compensation (whether in deferred cash or deferred restricted common stock) for purposes of calculating benefits and eligible compensation is subject to certain Internal Revenue Code limitations; and (2) a credit equal to the amount of El Paso's matching contribution to El Paso's Retirement Savings Plan that cannot be made because of a participant's deferred compensation and Internal Revenue Code limitations. The plan may not be terminated so long as the Pension Plan and/or Retirement Savings Plan remain in effect. The management committee of this plan designates who may participate and also administers the plan. Benefits under El Paso's Supplemental Benefits Plan are paid upon termination of employment in a lump-sum payment. In the event of a change in control (as defined under the Key Executive Severance Protection Plan) of El Paso, the supplemental pension benefits become fully vested and nonforfeitable.

Senior Executive Survivor Benefits Plan. This plan provides certain senior executives (including each of the named executives in this Annual Report on Form 10-K, except for Messrs. Wise and Kuehn who are no longer employees) of El Paso and its subsidiaries who are designated by the plan administrator with survivor benefit coverage in lieu of the coverage provided generally for employees under El Paso's group life insurance plan. The amount of benefits provided, on an after-tax basis, is two and one-half times the executive's annual salary. Benefits are payable in installments over 30 months beginning within 31 days after the executive's death, except that the plan administrator may, in its discretion, accelerate payments.

Benefits Protection Trust Agreement. El Paso maintains a trust for the purpose of funding certain of its employee benefit plans (including the severance protection plans described above). The trust consists of a trustee expense account, which is used to pay the fees and expenses of the trustee, and a benefit account, which is made up of three subaccounts and used to make payments to participants and beneficiaries in the participating plans. The trust is revocable by El Paso at any time before a "threatened change in control" (which is generally defined to include the commencement of actions that would lead to a "change in control" (as defined under the Key Executive Severance Protection Plan)) as to assets held in the trustee expense account, but is not revocable (except as provided below) as to assets held in the benefit account at any time. The trust generally becomes fully irrevocable as to assets held in the trust upon a threatened change in control. The trust is a grantor trust for federal tax purposes, and assets of the trust are subject to claims by El Paso's general creditors in preference to the claims of plan participants and beneficiaries. Upon a threatened change in control, El Paso must deliver $1.5 million in cash to the trustee expense account. Prior to a threatened change in control, El Paso may freely withdraw and substitute the assets held in the benefit account, other than the initially funded amount; however, no such assets may be withdrawn from the benefit account during a threatened change in control period. Any assets contributed to the trust during a threatened change in control period may be withdrawn if the threatened change in control period ends and there has been no threatened change in control. In addition, after a change in control occurs, if the trustee determines that the amounts held in the trust are less than "designated percentages" (as defined in the Trust Agreement) with respect to each subaccount in the benefit account, the trustee must make a written demand on El Paso to deliver funds in an amount determined by the trustee sufficient to attain the designed percentages. Following a change in control and if the trustee has not been requested to pay benefits from any subaccount during a "determination period" (as defined in the Trust Agreement), El Paso may make a written request to the trustee to withdraw certain amounts which were allocated to the subaccounts after the change in control occurred. The trust generally may be amended or terminated at any time, provided that no amendment or termination may result, directly or indirectly, in the return of any assets of the benefit account to El Paso prior to the satisfaction of all liabilities under the participating plans (except as described above) and no amendment may be made unless El Paso, in its reasonable discretion, believes that such amendment would have no material adverse effect on the amount of benefits payable under the trust to participants. In addition, no amendment may be made after the occurrence of a change in control which would (i) permit El Paso to withdraw any assets from the trustee expense account, (ii) directly or indirectly reduce or restrict the trustee's rights and duties under the trust, or (iii) permit El Paso to remove the trustee following the date of the change in control.

Alternative Benefits Program (ABP). In 2001, Mr. Wise reduced the balance of certain compensation payable to him under the Supplemental Benefits Plan by $5,000,000, in exchange for the right to participate in the ABP. The program provides for a loan to purchase a life insurance policy under a family trust. The amount of the loan to Mr. Wise was $9,000,000. The trust is the named beneficiary under the life insurance policy, and the loan with accrued interest will be repaid, on an after-tax basis, with proceeds of the policy after the participant's, or his spouse's death, whichever is later. The compensation that was reduced had been awarded in prior years and was disclosed as required in earlier proxy statements of El Paso. The cost of this program will not exceed the cost El Paso would have paid as compensation with respect to the reduced amounts. An amount of $2,608 was imputed as income in 2003 for Mr. Wise and is included, to the extent required under the rules of the SEC, in the "Other Annual Compensation" column to the Summary Compensation Table. This program is now closed to new participants.

Director Indemnification Agreements

El Paso has entered into indemnification agreements with each member of the Board of Directors as part of El Paso's indemnification program and in order to enable El Paso to attract and retain qualified directors. The indemnification agreements provide for payment of reasonable expenses (including attorneys' fees) incurred by each of the directors in defending a proceeding related to their service as a director in advance of its final disposition. El Paso may maintain insurance, enter into contracts, create a trust fund or use other means available to ensure payment of any indemnity payments and expense advances. In the event of a change in control of El Paso, El Paso is obligated to pay the costs of independent legal counsel who will be selected to provide legal advice with respect to all matters concerning the rights of each director to indemnity payments and expense advances after any such change in control.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

EQUITY COMPENSATION PLAN INFORMATION TABLE

The following table provides information concerning equity compensation plans as of December 31, 2003, that have been approved by stockholders and equity compensation plans that have not been approved by stockholders. The table includes (a) the number of securities to be issued upon exercise of options, warrants and rights outstanding under the equity compensation plans, (b) the weighted-average exercise price of all outstanding options, warrants and rights and (c) additional shares available for future grants under all of El Paso's equity compensation plans.

Plan Category	(a) Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights[1]	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by stockholders	6,954,152	$34.75	6,056,015[2]
Equity compensation plans not approved by stockholders	26,544,491	$52.50	25,890,530[3]
Total	33,498,643		31,946,545

(1) Column (a) does not include 2,759,206 shares with a weighted-average exercise price of $36.84 per share which were assumed by El Paso under the Executive Award Plan of Sonat Inc. as a result of the merger with Sonat in October 1999. The Executive Award Plan of Sonat Inc. has been terminated and no future awards can be made under it.

(2) In column (c), equity compensation plans approved by stockholders include 2,831,050 shares available for future issuance under the Employee Stock Purchase Plan.

(3) In column (c), equity compensation plans not approved by stockholders include 71,800 shares available for future awards granted under the Restricted Stock Award Plan for Management Employees.

Stockholder Approved Plans

2001 Omnibus Incentive Compensation Plan. This plan provides for the grant to officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. A maximum of 6,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator designates which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a "change in control" (defined in substantially the same manner as under the Key Executive Severance Protection Plan) of El Paso occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; (3) designated amounts of performance units become fully vested; (4) all restrictions placed on awards of restricted stock automatically lapse; and (5) the current year's target bonus amount becomes payable for each officer participating in the plan within 30 days, assuming target levels of performance were achieved by El Paso and the officer for the year in which the change in control occurs, or the prior year if target levels have not been established for the current year, except that no bonus amounts will become payable in connection with a change in control that results solely from a change to the Board of Directors of El Paso. The plan generally may be amended or terminated at any time. Any amendment following a change in control that impairs participants' rights requires participant consent.

1999 Omnibus Incentive Compensation Plan and 1995 Omnibus Compensation Plan — Terminated Plans. These plans provided for the grant to eligible officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. These plans have been replaced by the 2001 Omnibus Incentive Compensation Plan. Although these plans have been terminated with respect to new grants, certain stock options and shares of restricted stock remain outstanding under them. If a "change in control" of El Paso occurs, all outstanding stock options become fully exercisable and restrictions placed on restricted stock lapse. For purposes of the plans, the term "change in control" has substantially the same meaning given such term in the Key Executive Severance Protection Plan.

Non-stockholder Approved Plans

Strategic Stock Plan. This plan is an equity compensation plan that has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to non-employee members of the Board of Directors, officers and key employees of El Paso and its subsidiaries primarily in connection with El Paso's strategic acquisitions. A maximum of 4,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator determines which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a change in control, as defined earlier under the Key Executive Severance Protection Plan, of El Paso occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan.

Restricted Stock Award Plan for Management Employees. This plan is an equity compensation plan which has not been approved by the stockholders. The plan provides for the granting of restricted shares of El Paso's common stock to management employees (other than executive officers and directors) of El Paso and its subsidiaries for specific accomplishments beyond that which are normally expected and which will have a significant and measurable impact on the long-term profitability of El Paso. A maximum of 100,000 shares in the aggregate may be subject to awards under this plan. The plan administrator designates which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan.

Omnibus Plan for Management Employees. This plan is an equity compensation plan which has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted stock to salaried employees (other than employees covered by a collective bargaining agreement) of El Paso and its subsidiaries. A maximum of 58,000,000 shares in the aggregate may be subject to awards under this plan. If a change in control, as defined earlier under the Key Executive Severance Protection Plan, of El Paso occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information as of August 31, 2004 (unless otherwise noted) regarding beneficial ownership of common stock by each director, our Chief Executive Officer, the other four most highly compensated executive officers in the last fiscal year, our directors and executive officers as a group and each person or entity known by El Paso to own beneficially more than 5% of its outstanding shares of common stock. No family relationship exists between any of the directors or executive officers of El Paso.

Title of Class	Name of Beneficial Owner	Beneficial Ownership (Excluding Options)(1)	Stock Options(2)	Total	Percent of Class
Common Stock	Pacific Financial Research Inc.(3) 9601 Wilshire Boulevard, Suite 800 Beverly Hills, CA 90210	77,966,989	—	77,966,989	12.12%
Common Stock	Brandes Investment Partners, L.L.C.(3) 11988 El Camino Real Suite 500 San Diego, CA 92130	66,560,505	—	66,560,505	10.34%
Common Stock	State Street Bank and Trust Company(3) P.O. Box 1389 Boston, MA 02104-1389	36,713,773	—	36,713,773	5.71%
Common Stock	J.M. Bissell	58,107	12,000	70,107	*
Common Stock	J.C. Braniff	64,013(4)	21,000	85,013	*
Common Stock	J.L. Dunlap	23,121(5)	8,000	31,121	*
Common Stock	R.W. Goldman	26,125	8,000	34,125	*
Common Stock	A.W. Hall, Jr.	40,202	12,000	52,202	*
Common Stock	T.R. Hix	—	—	—	*
Common Stock	W.H. Joyce	1,000	—	1,000	*
Common Stock	R.L. Kuehn, Jr.	313,500(6)	614,300	927,800	*
Common Stock	J.C. MacNeil	48,296	12,000	60,296	*
Common Stock	J.M. Talbert	18,868	8,000	26,868	*
Common Stock	M. Wallop	53,149	11,000	64,149	*
Common Stock	J.L. Whitmire	28,243	8,000	36,243	*
Common Stock	J.B. Wyatt	50,674	14,000	64,674	*
Common Stock	D.L. Foshee	507,199	200,000	707,199	*
Common Stock	J.W. Somerhalder II	392,318	439,250	831,568	*
Common Stock	D.D. Scott	169,070	140,247	309,317	*
Common Stock	R.G. Phillips	604,562	303,500	908,062	*
Common Stock	R.W. Baker	145,240	183,709	328,949	*
Common Stock	W.A. Wise	1,796,658(7)	1,621,917(8)	3,418,575	*
Common Stock	Directors and executive officers as a group 20 persons total, including those individuals listed above	4,491,270	3,616,923	8,108,193	1.25%

* Less than 1%

(1) The individuals named in the table have sole voting and investment power with respect to shares of El Paso common stock beneficially owned, except that Mr. Talbert shares with one or more other individuals voting and investment power with respect to 5,000 shares of common stock. This column also includes shares of common stock held in El Paso's Benefits Protection Trust (as of August 31, 2004) as a result of deferral elections made in accordance with El Paso's benefit plans. These individuals share voting power with the trustee under that plan and receive dividends on such shares, but do not have the power to dispose of, or direct the disposition of, such shares until such shares are distributed. In addition, some shares of common stock reflected in this column for certain individuals are subject to restrictions. According to a Schedule 13G filed on February 12, 2004, as of December 31, 2003, Pacific Financial Research Inc. had sole voting power over 73,052,989 shares of common stock, no voting power over 4,914,000 shares of common stock and sole dispositive power of 77,966,989 shares of common stock. According to a Schedule 13G/A filed on March 10, 2004, as of December 31, 2003, Brandes Investment Partners, L.L.C. had shared voting power of 50,154,789 shares of common stock and shared dispositive power over 66,560,505 shares of common stock. According to a

Schedule 13G filed on March 26, 2004, as of December 31, 2003, State Street Bank and Trust Company had sole voting power over 16,334,497 shares of common stock, shared voting power over 19,108,114 shares of common stock, sole dispositive power over 17,571,967 shares of common stock and shared dispositive power of 19,141,806 shares of common stock.

(2) The directors and executive officers have the right to acquire the shares of common stock reflected in this column within 60 days of August 31, 2004, through the exercise of stock options.

(3) Stock ownership as of December 31, 2003, for Pacific Financial Research Inc., Brandes Investment Partners, L.L.C. and State Street Bank and Trust Company was reported on separate Schedules 13G filed on February 12, 2004, March 10, 2004 and March 26, 2004, respectively.

(4) Mr. Braniff's beneficial ownership excludes 3,500 shares of El Paso common stock owned by his wife, of which Mr. Braniff disclaims any beneficial ownership.

(5) Mr. Dunlap's beneficial ownership excludes 900 shares held by his wife as trustee. Mr. Dunlap disclaims any beneficial ownership in those shares.

(6) Mr. Kuehn's beneficial ownership excludes 27,720 shares of El Paso common stock owned by his wife or children, of which Mr. Kuehn disclaims any beneficial ownership.

(7) Mr. Wise's stock ownership is as of March 12, 2003, when he left the company. Mr. Wise's beneficial ownership excludes 400 shares of El Paso common stock owned by his children under the Uniform Gifts to Minors Act, of which Mr. Wise disclaims any beneficial ownership.

(8) Includes 98,000 stock options held in the William & Marie Wise Family Ltd. Partnership.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

We own 50 percent of the one percent general partner interest of GulfTerra, a publicly traded master limited partnership, and 17.8 percent of the partnership's common units. In addition, we own all of the outstanding Series C units of the partnership. Some of our directors, officers and other personnel who provide services for us also provide services for GulfTerra. These shared personnel own and are awarded units, or options to purchase units, in GulfTerra from time to time, and their personal financial interests may not always be completely aligned with ours.

A discussion of agreements, arrangements and transactions between us and GulfTerra is summarized in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, under the heading "Field Services". Also see Part II, Item 8, Financial Statements and Supplementary Data, Note 28.

Mr. Wise had two sons-in-law and a sister-in-law who were employed by El Paso or its subsidiaries during fiscal year 2003 and earned and/or received compensation (and in the case of one son-in-law and his sister-in-law, severance payments in connection with their termination of employment) in the amount of $85,829, $242,769, and $71,844, respectively. Mr. Phillips' brother was employed by El Paso or its subsidiaries during fiscal year 2003 and earned and/or received compensation and severance in connection with his termination of employment in the amount of $168,574.

See "Employment Contracts, Termination of Employment, Change in Control Arrangements and Director Indemnification Agreements" in Item 11, Executive Compensation of this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees for professional services rendered for El Paso by PricewaterhouseCoopers LLP for the years ended December 31, 2003 and 2002, were:

	December 31, 2003	December 31, 2002
Audit	$11,100,000	$10,840,000
Audit Related	2,620,000	670,000
Tax	850,000	770,000
All Other	90,000	430,000
Total	$14,660,000	$12,710,000

The *Audit* fees for the years ended December 31, 2003 and 2002, respectively, were for professional services rendered for the audits of the consolidated financial statements of El Paso, statutory subsidiary and equity investee audits, the review of documents filed with the Securities and Exchange Commission, consents, and the issuance of comfort letters.

The *Audit Related* fees for the years ended December 31, 2003 were for professional services rendered for the carve-out audits of businesses disposed of by El Paso, Sarbanes-Oxley Act of 2002 Section 404 readiness assessment, responding to inquiries of certain federal agencies related to audit work performed, working capital review of certain discontinued operations, accounting consultations, and other attest services. Fees for the year ended December 31, 2002 were for services rendered for internal audit services, due diligence related to acquisitions, accounting consultations pertaining to divestitures, and other attest services.

Tax fees for the years ended December 31, 2003 and 2002, respectively, were for professional services related to tax compliance and tax planning.

All Other fees for the year ended December 31, 2003 were for professional services rendered for other advisory services. Fees for the year ended December 31, 2002 were for services rendered for risk management and environmental advisory services.

Policy for Approval of Audit and Non-Audit Fees. During 2003, the Audit Committee approved all the types of audit and non-audit services which PricewaterhouseCoopers LLP was to perform during the year and the range of fees for each of these categories, as required under applicable law. The Audit Committee's current practice is to consider for pre-approval annually all categories of audit and non-audit services proposed to be provided by our independent auditors for the fiscal year. The Audit Committee will also consider for pre-approval annually the range of fees and the manner in which the fees are determined for each type of pre-approved audit and non-audit services proposed to be provided by our independent auditors for the fiscal year. The Audit Committee must separately pre-approve any service that is not included in the approved list of services or any proposed services exceeding pre-approved cost levels. The Audit Committee has delegated pre-approval authority to the Chairman of the Audit Committee for services that need to be addressed between Audit Committee meetings. The Audit Committee is then informed of these pre-approval decisions, if any, at the next meeting of the Audit Committee. In selecting PricewaterhouseCoopers LLP as our independent auditor, the Audit Committee believes the provision of the audit and non-audit services rendered by PricewaterhouseCoopers LLP is compatible with maintaining that firm's independence.

The Audit Committee has considered whether the provision of non-audit services by PricewaterhouseCoopers LLP is compatible with maintaining auditor independence and has determined that auditor independence has not been compromised.

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.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

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

(b) Reports on Form 8-K:

Date	Event Reported
November 18, 2003	Announced resignation of Rodney Erskine, President of El Paso Production Company and the appointment of Robert W. Baker as Executive Vice President and General Counsel of El Paso.
November 24, 2003	Filed agreements relating to the offering by El Paso of 8,790,436 shares of El Paso common stock.
December 4, 2003	Announced the completion of the sale of our North American nitrogen assets.
December 9, 2003	Announced the completion of the sale of our interest in Portland Natural Gas Transmission System.
December 15, 2003	Announced our Long-Range Plan.
December 15, 2003	Announced that we entered into a series of agreements with Enterprise Products Partners, L.P. in which Enterprise would merge with and into our subsidiary GulfTerra Energy Partners, L.P. with GulfTerra surviving as a wholly owned subsidiary of Enterprise.
December 22, 2003	Announced several events which have occurred following the announcement of our Long-Range plan.

Date	Event Reported
December 30, 2003	Filed agreements relating to the offering by El Paso of 8,790,436 shares of El Paso common stock.
January 5, 2004	Announced that we received final payment with regards to the sale of East Coast Power, L.L.C.; that we completed a Purchase and Sale agreement for our Coastal Eagle Point Refinery and that progress has been made on three petroleum asset sales.
January 8, 2004	Filed agreements relating to the offering by El Paso of 8,790,436 shares of El Paso common stock.
January 14, 2004	Announced the close of the sale of the Coastal Eagle Point Refinery and related working inventories.
January 16, 2004	Announced that our business unit, El Paso Merchant Energy, has agreed to sell 25 domestic power generation facilities.
February 2, 2004	Reported on a presentation by our Chief Financial Officer to an investor conference on the progress made in implementing our long range business plan.
February 4, 2004	Announced that we have agreed to sell our Aruba refinery and related assets.
February 5, 2004	Amended the February 4, 2004 Form 8-K due to an incorrect date which appeared in the earlier Form 8-K.
February 17, 2004	Announced that we have agreed to sell El Paso Oil and Gas Canada, Inc.
February 17, 2004	Announced the completion of our annual review of natural gas and oil estimates.
March 10, 2004	Announced that we will delay the release of our fourth quarter 2003 earnings pending completion of a review of the impact of our recently announced reserve revision.
March 15, 2004	Announced update on our debt reduction progress.
March 16, 2004	Announced that we received waivers on our $3 billion revolving credit facility that are required to address potential issues related to our recently announced reserve revisions.
March 25, 2004	Announced sale of El Paso Oil & Gas Canada, Inc. to BG Group for approximately $352 million in cash.
March 26, 2004	Announced we agreed to sell 100 percent of Utility Contract Funding to Bear Stearns Houston Energy Group.
April 13, 2004	Announced sale of one-third of our interest in a portion of our Australian pipeline holdings to Hastings Fund Management.
April 21, 2004	Announced amendment to agreements providing for the merger between Enterprise Products Partners L.P. and GulfTerra Energy Partners, L.P.
April 22, 2004	Announced agreement to sell interest in power plant located in Bastrop, Texas to FPL Energy, L.L.C.
May 3, 2004	Announced findings of an independent review of the Audit Committee of our Board of Directors concerning the revisions to our natural gas and oil reserves.
May 5, 2004	Clarification to prior disclosures regarding the independent review of the revisions to our natural gas and oil reserves.
May 20, 2004	Announced that Thomas R. Hix and William H. Joyce will join the El Paso Board of Directors effective May 20, 2004.
May 28, 2004	Announced 2004 Annual Meeting date and progress on our Long-Range Plan (includes information furnished under Item 12).

Date	Event Reported
June 15, 2004	Announced that the Master Settlement Agreement to the western energy crisis became effective on July 11, 2004.
June 16, 2004	Announced that we received waivers on our $3 billion revolving credit facility and certain other financings.
June 21, 2004	Announced that we closed the sale of our interests in Utility Contract Funding (UCF) to a subsidiary of The Bear Stearns Companies Inc., for approximately $21 million.
June 25, 2004	Announced the temporary suspension of trading in the El Paso company stock fund under our retirement savings plan.
June 29, 2004	Announced that our subsidiary had entered into an agreement to purchase a 50-percent interest in UnoPaso.
June 29, 2004	Provided an update of our strategic plan for our production business.
July 7, 2004	Announced that we had closed the sale of four domestic power generating facilities for approximately $226 million plus the assumption of approximately $39 million of non-recourse debt.
July 9, 2004	Announced that our subsidiary, El Paso Production Holding Company, has entered into an agreement with the holders of a majority of its 7¾% senior notes for a waiver of its breach of the covenant to timely file its annual and quarterly reports with the SEC.
July 21, 2004	Announced that we had closed the sale of two domestic power generation facilities for approximately $97.4 million.
July 27, 2004	Announced that we had closed the sale of 10 domestic power generating facilities for $28 million, and that on July 23, 2004 we announced that our subsidiary had closed the sale of an equity investment for $23.2 million plus working capital.
August 10, 2004	Announced that we expect to file our 2003 Form 10-K before September 30, 2004. We also announced that we received additional waivers on our $3 billion revolving credit facility and certain other financings. We amended the $3 billion revolving credit facility to (i) limit our ability and that of our consolidated subsidiaries to repay indebtedness that is not scheduled to occur before June 30, 2005 (the maturity date under the revolving credit facility) and (ii) modify one of the events of default under the credit facility. These waivers provide us with an extension until September 30, 2004 to file our 2003 Form 10-K and until November 30, 2004 to file our first and second quarter 2004 Form 10-Q's.
August 17, 2004	Announced preparations for its 2004 annual meeting of stockholders.

We also furnished information to the SEC in Item 9 (now Item 7.01) and Item 12 (now Item 2.02) Current Reports on Form 8-K. These Current Reports on Form 8-K are not considered to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 and are not subject to the liabilities of that section.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS
WITH REPORT OF INDEPENDENT AUDITORS
December 31, 2003

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2003	2002	2001
Operating revenues			
Natural gas pipelines and plants			
Natural gas sales	$ 171,738	$ 85,001	$ 59,701
NGL sales	121,167	32,978	—
Gathering and transportation	388,777	194,336	33,849
Processing	52,988	45,266	7,133
	734,670	357,581	100,683
Oil and NGL logistics			
Oil sales	2,231	108	—
Oil transportation	26,769	8,364	7,082
Fractionation	22,034	26,356	25,245
NGL storage	2,816	2,817	—
	53,850	37,645	32,327
Platform services	20,861	16,672	15,385
Natural gas storage	44,297	28,602	19,373
Other — oil and natural gas production	17,811	16,890	25,638
	871,489	457,390	193,406
Operating expenses			
Cost of natural gas and other products	287,157	108,819	51,542
Operation and maintenance	189,702	115,162	33,279
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
	557,026	296,580	134,887
Operating income	314,463	160,810	58,519
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Minority interest income (expense)	(917)	60	(100)
Other income	1,206	1,537	28,726
Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	—
Income from continuing operations	161,449	92,552	54,052
Income from discontinued operations	—	5,136	1,097
Cumulative effect of accounting change	1,690	—	—
Net income	$ 163,139	$ 97,688	$ 55,149

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME — (Continued)
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2003	2002	2001
Income allocation			
Series B unitholders	$11,792	$14,688	$17,228
General partner			
Income from continuing operations	$69,414	$42,082	$24,650
Income from discontinued operations	—	51	11
Cumulative effect of accounting change	17	—	—
	$69,431	$42,133	$24,661
Common unitholders			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	—	5,085	1,086
Cumulative effect of accounting change	1,340	—	—
	$66,495	$39,360	$13,260
Series C unitholders			
Income from continuing operations	$15,088	$ 1,507	$ —
Cumulative effect of accounting change	333	—	—
	$15,421	$ 1,507	$ —
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.03	—	—
Net income	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.02	—	—
Net income	$ 1.32	$ 0.92	$ 0.38
Basic weighted average number of common units outstanding	49,953	42,814	34,376
Diluted weighted average number of common units outstanding	50,231	42,814	34,376

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 30,425	$ 36,099
Accounts receivable, net		
Trade	43,203	90,379
Unbilled trade	63,067	49,140
Affiliates	47,965	83,826
Affiliated note receivable	3,768	—
Other current assets	20,595	3,451
Total current assets	209,023	262,895
Property, plant and equipment, net	2,894,492	2,724,938
Intangible assets	3,401	3,970
Investments in unconsolidated affiliates	175,747	95,951
Other noncurrent assets	38,917	43,142
Total assets	$3,321,580	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	$ 113,820	$ 120,140
Affiliates	38,870	86,144
Accrued gas purchase costs	15,443	6,584
Accrued interest	11,199	15,028
Current maturities of senior secured term loan	3,000	5,000
Other current liabilities	27,035	21,195
Total current liabilities	209,367	254,091
Revolving credit facility	382,000	491,000
Senior secured term loans, less current maturities	297,000	552,500
Long-term debt	1,129,807	857,786
Other noncurrent liabilities	49,043	23,725
Total liabilities	2,067,217	2,179,102
Commitments and contingencies		
Minority interest	1,777	1,942
Partners' capital		
Limited partners		
Series B preference units; 125,392 units in 2002 issued and outstanding	—	157,584
Common units; 58,404,649 and 44,030,314 units in 2003 and 2002 issued and outstanding	898,072	433,150
Series C units; 10,937,500 units in 2003 and 2002 issued and outstanding	341,350	350,565
General partner	13,164	8,553
Total partners' capital	1,252,586	949,852
Total liabilities and partners' capital	$3,321,580	$3,130,896

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities			
Net income	$ 163,139	$ 97,688	$ 55,149
Less cumulative effect of accounting change	1,690	—	—
Less income from discontinued operations	—	5,136	1,097
Income from continuing operations	161,449	92,552	54,052
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(11,373)	(13,639)	(8,449)
Distributions from unconsolidated affiliates	12,140	17,804	35,062
(Gain) loss on sale of long-lived assets	(18,679)	473	11,367
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434	—
Amortization of debt issuance costs	7,498	4,443	3,608
Other noncash items	3,445	4,429	544
Working capital changes, net of acquisitions and non-cash transactions			
Accounts receivable	66,441	(167,536)	(41,037)
Other current assets	(9,762)	(12,612)	125
Other noncurrent assets	(1,540)	467	(10,379)
Accounts payable	(45,829)	143,553	(672)
Accrued gas purchase costs	8,859	4,223	(2,776)
Accrued interest	(3,829)	9,330	3,574
Other current liabilities	(8,928)	13,086	(235)
Other noncurrent liabilities	(3,114)	(377)	(1,067)
Net cash provided by continuing operations	268,168	170,756	82,416
Net cash provided by discontinued operations	—	5,244	4,968
Net cash provided by operating activities	268,168	176,000	87,384
Cash flows from investing activities			
Development expenditures for oil and natural gas properties	(145)	(1,682)	(2,018)
Additions to property, plant and equipment	(332,019)	(202,541)	(508,347)
Proceeds from the sale and retirement of assets	77,911	5,460	109,126
Additions to investments in unconsolidated affiliates	(35,536)	(38,275)	(1,487)
Proceeds from the sale of investments in unconsolidated affiliates	1,355	—	—
Repayments on note receivable	1,238	—	—
Cash paid for acquisitions, net of cash acquired	(20)	(1,164,856)	(28,414)
Net cash used in investing activities of continuing operations	(287,216)	(1,401,894)	(431,140)
Net cash provided by (used in) investing activities of discontinued operations	—	186,477	(68,560)
Net cash used in investing activities	(287,216)	(1,215,417)	(499,700)

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(In thousands)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from financing activities			
Net proceeds from revolving credit facility	533,564	366,219	559,994
Repayments of revolving credit facility	(647,000)	(177,000)	(581,000)
Net proceeds from GulfTerra Holding term credit facility	—	530,136	—
Repayment of GulfTerra Holding term credit facility	—	(375,000)	—
Repayment of GulfTerra Holding term loan	(160,000)	—	—
Net proceeds from senior secured acquisition term loan	(23)	233,236	—
Repayment of senior secured acquisition term loan	(237,500)	—	—
Net proceeds from senior secured term loan	299,512	156,530	—
Repayment of senior secured term loan	(160,000)	—	—
Net proceeds from issuance of long-term debt	537,426	423,528	243,032
Repayments of long-term debt	(269,401)	—	—
Repayment of Argo term loan	—	(95,000)	—
Distributions to minority interests	(1,242)	—	—
Net proceeds from issuance of common units	509,010	150,159	286,699
Redemption of Series B preference units	(155,673)	—	(50,000)
Contributions from general partner	3,098	4,095	2,843
Distributions to partners	(238,397)	(154,468)	(106,409)
Net cash provided by financing activities of continuing operations	13,374	1,062,435	355,159
Net cash provided by (used in) financing activities of discontinued operations	—	(3)	49,960
Net cash provided by financing activities	13,374	1,062,432	405,119
Increase (decrease) in cash and cash equivalents	(5,674)	23,015	(7,197)
Cash and cash equivalents at beginning of year	36,099	13,084	20,281
Cash and cash equivalents at end of year	$ 30,425	$ 36,099	$ 13,084

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(In thousands)

	Series B Preference Units[1]	Series B Preference Unitholders	Series C Units[2]	Series C Unitholders	Common Units	Common Unitholders	General Partner[3]	Total
Partners' capital at January 1, 2001	170	$ 175,668	—	$ —	31,550	$ 132,802	$ 2,601	$ 311,071
Net income[4]	—	17,228	—	—	—	13,260	24,661	55,149
Other comprehensive loss	—	—	—	—	—	(1,259)	(13)	(1,272)
Issuance of common units	—	—	—	—	8,189	286,699	—	286,699
Issuance of unit options	—	—			—	2,161	—	2,161
Redemption of Series B preference units	(45)	(50,000)	—	—	—	—	—	(50,000)
General partner contribution related to the issuance of common units	—	—	—	—	—	—	2,843	2,843
Cash distributions	—	—	—	—	—	(80,903)	(25,022)	(105,925)
Partners' capital at December 31, 2001	125	$ 142,896	—	$ —	39,739	$ 352,760	$ 5,070	$ 500,726
Net income[4]	—	14,688	—	1,507	—	39,360	42,133	97,688
Issuance of Series C units	—	—	10,938	350,000	—	—	—	350,000
Other comprehensive loss	—	—	—	(942)	—	(3,364)	(44)	(4,350)
Issuance of common units	—	—	—	—	4,291	156,072	—	156,072
Issuance of unit options	—	—	—	—	—	89	—	89
General partner contribution related to the issuance of Series C units and common units	—	—	—	—	—	—	4,095	4,095
Cash distributions	—	—	—	—	—	(111,767)	(42,701)	(154,468)
Partners' capital at December 31, 2002	125	$ 157,584	10,938	$350,565	44,030	$ 433,150	$ 8,553	$ 949,852
Net income[4]	—	11,792	—	15,421		66,495	69,431	163,139
Other comprehensive loss	—		—	(467)	—	(2,865)	(73)	(3,405)
Issuance of common units	—	—	—	—	14,056	494,812	—	494,812
Issuance of Series F units	—	—	—	—	—	4,104	—	4,104
Redemption of unit options	—	—	—	—	319	10,094	—	10,094
Redemption of Series B preference units	(125)	(169,376)	—	1,919	—	9,686	2,098	(155,673)
Issuance of unit options and restricted units						1,687		1,687
General partner contribution related to the issuance of common units	—	—	—	—	—	—	3,098	3,098
Receipt of communication assets	—	—	—	4,100	—	18,942	233	23,275
Cash distributions	—	—	—	(30,188)	—	(138,033)	(70,176)	(238,397)
Partners' capital at December 31, 2003	—	$ —	10,938	$341,350	58,405	$ 898,072	$ 13,164	$1,252,586

(1) In October 2003, we redeemed all of our remaining outstanding Series B preference units for $156 million.

(2) We issued 10,937,500 of our Series C units to El Paso Corporation for a value of $350 million in connection with our acquisition of the San Juan assets. A discussion of this new class of units is included in Note 8.

(3) GulfTerra Energy Company, L.L.C. is our sole general partner and is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise Products Partners, L.P.

(4) Income allocation to our general partner includes both its incentive distributions and its one percent ownership interest.

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
(In thousands)

Comprehensive Income

	Year Ended December 31,		
	2003	2002	2001
Net income	$163,139	$97,688	$55,149
Other comprehensive loss	(3,405)	(4,350)	(1,272)
Total comprehensive income	$159,734	$93,338	$53,877

Accumulated Other Comprehensive Income (Loss)

	Year Ended December 31,		
	2003	2002	2001
Beginning balance	$ (5,622)	$(1,272)	$ —
Unrealized mark-to-market losses on cash flow hedges arising during period	(12,924)	(6,428)	(1,682)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	10,018	1,579	410
Accumulated other comprehensive income (loss) from investment in unconsolidated affiliate	(499)	499	—
Ending balance	$ (9,027)	$(5,622)	$(1,272)

See accompanying notes.

1. Summary of Significant Accounting Policies

Organization

We are a publicly held Delaware master limited partnership established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. As of December 31, 2003, we had 58,404,649 common units outstanding representing limited partner interests and 10,937,500 Series C units outstanding representing non-voting limited partner interests. On that date, the public owned 48,020,404 common units, or 82.2 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our Series C units and 50 percent of our general partner, which owns our one percent general partner interest.

In May 2003, we changed our name to GulfTerra Energy Partners, L.P. from El Paso Energy Partners, L.P. and reorganized our general partner. In connection with our name change, we also changed the names of several subsidiaries in May 2003, including the following, as listed in the table below.

New Name	Former Name
GulfTerra Energy Finance Corporation	El Paso Energy Partners Finance Corporation
GulfTerra Arizona Gas, L.L.C.	El Paso Arizona Gas, L.L.C.
GulfTerra Intrastate, L.P.	El Paso Energy Intrastate, L.P.
GulfTerra Texas Pipeline, L.P.	EPGT Texas Pipeline, L.P.
GulfTerra Holding V, L.P.	EPN Holding Company, L.P.

Our sole general partner is GulfTerra Energy Company, L.L.C., a recently-formed Delaware limited liability company that is owned 50 percent by a subsidiary of El Paso Corporation and 50 percent by a subsidiary of Enterprise, a publicly traded master limited partnership. El Paso Corporation (through its subsidiaries) owned 100 percent of our general partner until October 2003, when Goldman Sachs acquired a 9.9 percent interest in our general partner. In December 2003, El Paso Corporation reacquired Goldman Sachs' interest in our general partner and then sold a 50 percent interest in our general partner to a subsidiary of Enterprise.

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs with Enterprise being the continuing entity. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest.

The combined partnership, which will retain the name Enterprise Products Partners L.P., will serve the largest producing basins of natural gas, crude oil and NGLs in the U.S., including the Gulf of Mexico, Rocky Mountains, San Juan Basin, Permian Basin, South Texas, East Texas, Mid-Continent and Louisiana Gulf Coast basins and, through connections with third-party pipelines, Canada's western sedimentary basin. The partnership will also serve the largest consuming regions for natural gas, crude oil and NGLs on the U.S. Gulf Coast.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interest in twelve of our subsidiaries for $8 million. As a result of this acquisition, all of our subsidiaries, but not our equity investees, are wholly-owned by us.

During part of 2003 and 2002, third parties had minority ownership interests in Matagorda Island Area Gathering System (MIAGS) and Arizona Gas, L.L.C. The assets, liabilities and operations of these entities are included in our consolidated financial statements and we account for the third party ownership interest as minority interest in our consolidated balance sheets and as minority interest income (expense) in our consolidated statements of income. In October 2003, we purchased the remaining 17 percent interest in MIAGS. As a result, we no longer recognize the third party ownership interest in MIAGS as minority interests in our consolidated balance sheets or consolidated statements of income.

Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital. We have reflected the results of operations from our Prince assets disposition as discontinued operations for the years ended December 31, 2002 and 2001. See Note 2 for a further discussion of our Prince assets disposition.

Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our HIOS interstate natural gas system and our Petal storage facility are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects.

Under the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*, which we adopted on January 1, 2003, the cost associated with the retirement of long-lived assets for regulated entities accounted for under SFAS No. 71 should be classified as a regulatory liability instead of as a component of property, plant and equipment. As a result, we reclassified $13.6 million from property, plant and equipment to a regulatory liability and at December 31, 2003, this balance is included in other noncurrent liabilities in our consolidated balance sheet. Prior to January 2003, this item was reflected in accumulated depreciation, depletion and amortization and the balance for this item at December 31, 2002, was $12.9 million.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle (GAAP) of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. We review collectibility regularly and adjust the allowance as necessary, primarily under the specific identification method. At December 31, 2003 and 2002, the allowance was $4.0 million and $2.5 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure and are valued at prices representing the estimated value of these imbalances upon settlement. We estimate the value of our imbalances at prices representing the estimated value of the imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month-end spot prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying consolidated balance sheets. Our imbalance receivables and imbalance payables were as follows at December 31 (in thousands):

	2003	2002
Imbalance Receivables		
Trade	$37,228	$ 88,929
Affiliates	$16,405	$ 15,460
Imbalance Payables		
Trade	$68,446	$104,035
Affiliates	$14,047	$ 22,316

Property, Plant and Equipment

We record our property, plant and equipment at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Additionally, 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 also capitalize the major units of property replacements or improvements and expense minor items including repair and maintenance costs. In addition, we reduce our property, plant and equipment balance for any amounts that we receive in the form of contributions in aid of construction.

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff to the total cost of the group until its net book value equals its estimated salvage value. Currently, depreciation rates on our regulated interstate system and storage facility vary from 1 to 20 percent. Using these rates, the remaining depreciable lives of these assets range from 1 to 39 years.

Our non-regulated gathering pipelines, platforms and related facilities, processing facilities and equipment, and storage facilities and equipment are depreciated on a straight-line basis over the estimated useful lives which are as follows:

Gathering pipelines	5-40 years
Platforms and facilities	18-30 years
Processing facilities	25-30 years
Storage facilities	25-30 years

We account for our oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, developmental wells and acquisitions of mineral leasehold interests are capitalized. Production, exploratory dry hole and other exploration costs, including geological and geophysical costs and delay rentals, are expensed as incurred. Unproved properties are assessed periodically and any impairment in value is recognized currently as depreciation, depletion and amortization expense.

Depreciation, depletion and amortization of the capitalized costs of producing oil and natural gas properties, consisting principally of tangible and intangible costs incurred in developing a property and costs of productive leasehold interests, are computed on the unit-of-production method. Unit-of-production rates are based on annual estimates of remaining proved developed reserves or proved reserves, as appropriate, for each property.

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At December 31, 2002, accrued abandonment costs were $24.6 million, of which $6.4 million was related to offshore wells. As discussed below, we adopted SFAS No. 143 *Accounting for Asset Retirement Obligations* on January 1, 2003 and the amounts accrued and capitalized were adjusted to conform to the provisions of that statement.

Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation, depletion and amortization of the disposed assets with any resulting gain or loss reflected in income.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143. The provisions of this statement relate primarily to our obligations to plug abandoned offshore wells that constitute part of our non-segment assets.

Upon our adoption of SFAS No. 143, we recorded (i) a $7.4 million net increase to property, plant, and equipment, relating to offshore wells, representing non-current retirement assets, (ii) a $5.7 million increase to noncurrent liabilities representing retirement obligations, and (iii) a $1.7 million increase to income as a cumulative effect of accounting change. Each retirement asset is depreciated over the remaining useful life of the long-term asset with which the retirement liability is associated. An ongoing expense is recognized for the interest component of the liability due to the changes in the value of the retirement liability as a result of the passage of time, which we reflect as a component of depreciation expense in our income statement.

Other than our obligations to plug and abandon wells, we cannot estimate the costs to retire or remove assets used in our business because we believe the assets do not have definite lives or we do not have the legal obligation to abandon or dismantle the assets. We believe that the lives of our assets or the underlying reserves associated with our assets cannot be estimated. Therefore, aside from the liability associated with the plugging and abandonment of offshore wells, we have not recorded liabilities relating to any of our other assets.

The pro forma income from continuing operations and amounts per common unit for the years ended December 31, 2002 and 2001, assuming the provisions of SFAS No. 143 were adopted prior to the earliest period presented, are shown below:

	Years Ended December 31,	
	2002	2001
Pro forma income from continuing operations	$93,932	$54,321
Pro forma income from continuing operations allocated to common unitholders	$35,369	$12,446
Pro forma basic income from continuing operations per weighted average common unit	$ 0.83	$ 0.36
Pro forma diluted income from continuing operations per weighted average common unit	$ 0.83	$ 0.36

The pro forma amount of our asset retirement obligations at December 31, 2002 and 2001, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented was $5.7 million and $5.3 million. Our asset retirement obligation for December 31, 2003, is shown below.

Year	Liability Balance as of January 1	Accretion	Other Change in Liability	Liability Balance as of December 31
		(In thousands)		
2003	$5,726	$442	$(246)[1]	5,922

[1] Abandonment work performed during the year ended December 31, 2003.

Goodwill and Other Intangible Assets

We adopted the provisions of SFAS No. 142 *Goodwill and Other Intangible Assets* on January 1, 2002, except for goodwill and intangible assets we acquired after June 30, 2001 for which we adopted the provisions immediately. Accordingly, we record identifiable intangible assets we acquire individually or with a group of other assets at fair value upon acquisition. Identifiable intangible assets with finite useful lives are amortized to expense over the estimated useful life of the asset. Identifiable intangible assets with indefinite useful lives and goodwill are evaluated annually for impairment by comparison of their carrying amounts with the fair value of the individual assets. We recognize an impairment loss in income for the amount by which the carrying value of any identifiable intangible asset or goodwill exceeds the fair value of the specific assets. As of December 31, 2003 and 2002, we had no goodwill, other than as described below.

As of December 31, 2003 and 2002, the carrying amount of our equity investment in Poseidon exceeded the underlying equity in net assets by approximately $3.0 million. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount and will test it for impairment if an event occurs that indicates there may be a loss in value, or at least annually. Prior to January 1, 2002, we amortized this excess amount using the straight line method over approximately 30 years. This excess amount is reflected on our accompanying consolidated balance sheets in investments in unconsolidated affiliates. Our adoption of this statement did not have a material impact on our financial position or results of operations.

As part of our acquisition of the EPN Holding assets and the San Juan assets, we obtained intangible assets representing contractual rights under dedication and transportation agreements with producers. As of December 31, 2003 and 2002, the value of these intangible assets was approximately $3.4 million and

$4.0 million and is reflected on our accompanying consolidated balance sheets as intangible assets. We amortize the intangible assets acquired in the EPN Holding asset acquisition to expense using the units-of-production method over the expected lives of the reserves ranging from 26 to 45 years. We amortize the intangible assets acquired in the San Juan asset acquisition over the life of the contracts of approximately 4 years.

Impairment and Disposal of Long-Lived Assets

We apply the provisions of SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets* to account for impairment and disposal of long-lived assets. Accordingly, we evaluate the recoverability of long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value, less cost to sell, as an impairment loss in income from operations in the period the impairment is determined.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss in the period(s) in which they occur. Upon our adoption of SFAS No. 144, we reclassified our losses on the sale of long-lived assets of $0.4 million and $11.4 million for the years ended December 31, 2002 and 2001, into operating income to conform with the provisions of SFAS No. 144.

We also reclassify the asset or assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flow and whether we have any continuing involvement.

Capitalization of Interest

Interest and other financing costs are capitalized in connection with construction and drilling activities as part of the cost of the asset and amortized over the related asset's estimated useful life.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. At December 31, 2003 and 2002, the unamortized amount of our debt issue costs included in other noncurrent assets was $29.2 million and $32.6 million. Amortization of debt issue costs for the years ended December 31, 2003, 2002 and 2001 were $7.5 million, $4.4 million and $3.6 million and are included in interest and debt expense on our consolidated statements of income.

Revenue Recognition and Cost of Natural Gas and Other Products

Revenue from gathering and transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from commodity sales is recognized upon delivery. Commodity storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of the transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services, treating services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided. Other revenues generally are recorded when services have been provided or products have been delivered.

Prior to 2002, our cost of natural gas consisted primarily of natural gas purchased at GulfTerra Alabama Intrastate for resale. As a result of our acquisition of the EPN Holding assets and the San Juan assets, we are now incurring additional costs related to system imbalances and for the purchase of natural gas as part of our producer services activities. As a convenience for our producers, we may purchase natural gas from them at the wellhead at an index price less an amount that compensates us for our gathering services. We then sell this gas into the open market at points on our system at the same index price. We reflect these sales in our revenues and the related purchases as cost of natural gas on the accompanying consolidated statements of income.

Typhoon Oil Pipeline's transportation agreement with BHP and Chevron Texaco provides that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. Beginning in 2003, we record revenue from these buy/sell transactions upon delivery of the oil based on the net amount billed to the producers. We acquired the Typhoon oil pipeline in November 2002, and for the year ended December 31, 2002, we recorded revenue based on the gross amount billed to the producers. For the year ended December 31, 2002, we reclassified $10.5 million from cost of natural gas and other products to revenue to conform to our 2003 presentation. This reclassification has no effect on operating income, net income or partners' capital.

As of July 1, 2003, HIOS implemented new rates, subject to a refund, and we established a reserve for our estimate of the refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes.

Environmental Costs

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our consolidated balance sheets in other noncurrent liabilities at their undiscounted amounts.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we engage in price risk management activities for non-trading purposes to manage market risks associated with commodities we purchase and sell and interest rates on variable rate debt. Our price risk management activities involve the use of a variety of derivative financial instruments, including:

- exchange-traded future contracts that involve cash settlement;

- forward contracts that involve cash settlements or physical delivery of a commodity; and
- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity or variable rate debt instrument.

We account for all of our derivative instruments in our consolidated financial statements under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* We record all derivatives in our consolidated balance sheets at their fair value as other assets or other liabilities and classify them as current or noncurrent based upon their anticipated settlement date.

For those instruments entered into to hedge risk and which qualify as hedges, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. In addition to its designation, a hedge must be effective. To be effective, changes in the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking various hedge transactions. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is not highly effective as a hedge or if we decide to discontinue the hedging relationship.

During 2003, 2002 and 2001, we entered into cash flow hedges that qualify for hedge accounting under SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged. At the date of the hedged transaction, we reclassify the gains or losses resulting from the sale, maturity, extinguishment or termination of derivative instruments designated as hedges from accumulated other comprehensive income to operating income or interest expense, as appropriate, in our consolidated statements of income. We classify cash inflows and outflows associated with the settlement of our derivative transactions as cash flows from operating activities in our consolidated statements of cash flows.

We also record our ownership percentage of the changes in the fair value of derivatives of our investments in unconsolidated affiliates in accumulated other comprehensive income.

We may also purchase and sell instruments to economically hedge price fluctuations in the commodity markets. These instruments are not documented as hedges due to their short-term nature, or do not qualify under the provisions of SFAS No. 133 for hedge accounting due to the terms in the instruments. Where such derivatives do not qualify, or are not documented, changes in their fair value are recorded in earnings in the current period.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices in the San Juan Basin in anticipation of our acquisition of the San Juan assets. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Beginning with the acquisition date in November 2002, we have designated this derivative as a cash flow hedge and are accounting for it as such under SFAS No. 133.

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. This statement amends SFAS No. 133 to incorporate several interpretations of the Derivatives Implementation Group (DIG), and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. There was no initial financial statement impact of adopting this standard, although the FASB and DIG continue to deliberate on the application of the standard to certain derivative contracts, which may impact our financial statements in the future.

Income Taxes

As of December 31, 2003, neither we nor any of our subsidiaries are taxable entities. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

Income (Loss) per Common Unit

Basic income (loss) per common unit excludes dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period. Diluted income (loss) per common unit reflects potential dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period increased by the number of additional common units that would have been outstanding if the potentially dilutive units had been issued.

Basic income (loss) per common unit and diluted income (loss) per common unit are the same for the years ended December 31, 2002 and 2001, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our GulfTerra Alabama Intrastate operations, our Indian Basin processing plant, the San Juan assets and our unconsolidated affiliate, Poseidon Oil Pipeline Company, L.L.C.

The following table presents our allocation of accumulated other comprehensive loss as of December 31:

	2003	2002	2001
Common units' interest	$(7,488)	$(4,623)	$(1,259)
Series C units' interest	$(1,409)	$ (942)	$ —
General partner's interest	$ (130)	$ (57)	$ (13)

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 under our Omnibus Plan and Director Plan. For the years ending December 31, 2003, 2002 and 2001, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, to account for all of our other stock-based compensation programs.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure.* This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement is effective for fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation issued to individuals who are on our general partner's current board of directors and for those grants made prior to El Paso Corporation's acquisition of our general partner in August 1998 and will include data providing the pro forma income effect of using the fair value method as required by SFAS No. 148. We will continue to use the provisions of SFAS No. 123 to account for all of our other stock-based compensation programs.

If compensation expense related to these plans had been determined by applying the fair value method in SFAS No. 123 our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	Years Ended December 31,		
	2003	2002	2001
		(In thousands)	
Net income, as reported	$163,139	$97,688	$55,149
Add: Stock-based employee compensation expense included in reported net income	1,489	1,168	367
Less: Stock-based employee compensation expense determined under fair value based method	1,532	1,912	678
Pro forma net income	$163,096	$96,944	$54,838
Pro forma net income allocated to common unitholders	$ 66,452	$38,616	$12,949
Earnings per common unit:			
Basic, as reported	$ 1.33	$ 0.92	$ 0.38
Basic, pro forma	$ 1.33	$ 0.90	$ 0.38
Diluted, as reported	$ 1.32	$ 0.92	$ 0.38
Diluted, pro forma	$ 1.32	$ 0.90	$ 0.38

The effects of applying SFAS No. 123 in this pro forma disclosure may not be indicative of future amounts.

Accounting for Debt Extinguishments

In January 2003, we adopted SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* Accordingly, we now evaluate the nature of any debt extinguishments to determine whether to report any gain or loss resulting from the early extinguishment of debt as an extraordinary item or as a component of income from continuing operations.

Accounting for Costs Associated with Exit or Disposal Activities

In January 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. This statement impacts any exit or disposal activities that we initiate after January 1, 2003 and we now recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Our adoption of this pronouncement did not have an effect on our financial position or results of operations.

Accounting for Guarantees

In accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*, we record a liability at fair value, or otherwise disclose, certain guarantees issued after December 31, 2002, that contractually require us to make payments to a guaranteed party based on the occurrence of certain events. We have not entered into any material guarantees that would require recognition under FIN No. 45.

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

In May 2003, the 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. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. We adopted the provisions of SFAS No. 150 on July 1, 2003, and our adoption had no material impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires a company to consolidate a VIE if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. In December 2003, the FASB issued FIN 46-R, which amended FIN No. 46, to extend its effective date until the first quarter of 2004 for all types of entities except special purpose entities (SPE's). In addition, FIN No. 46-R also limited the scope of FIN No. 46 to exclude certain joint ventures of other entities that meet the characteristics of businesses.

We have no SPE's as defined by FIN Nos. 46 and 46-R. We have evaluated our joint ventures, unconsolidated subsidiaries and other contractual arrangements that could be considered variable interests or variable interest entities that were created before February 1, 2003 and have determined that they will not have a significant effect on our reported results and financial position when we adopt the provisions of FIN No. 46-R in the first quarter of 2004.

2. Acquisitions and Dispositions

Merger with Enterprise

On December 15, 2003, we, along with Enterprise and El Paso Corporation, announced that we had executed definitive agreements to merge Enterprise and GulfTerra to form one of the largest publicly traded MLPs. The general partner of the combined partnership will be jointly owned by affiliates of El Paso Corporation and privately-held Enterprise Products Company, with each owning a 50-percent interest. The definitive agreements include three transactions, of which two affect us.

In the first transaction that effects us, which occurred with the signing of the merger agreement, a wholly owned subsidiary of Enterprise purchased a 50 percent limited-voting interest in our general partner. This interest entitles Enterprise to half of the cash distributed to our general partner, but does not allow Enterprise to elect any of our general partner's directors or otherwise generally participate in our general partner's management of our business.

The second transaction that affects us will occur at the merger date. At the closing of the merger, each outstanding GulfTerra common unit (other than those owned by Enterprise) will convert into 1.81 Enterprise common units, GulfTerra will become a wholly-owned subsidiary of Enterprise, and El Paso Corporation will acquire a 50 percent interest in Enterprise's general partner (including the right to elect half of the directors of Enterprise's general partner). The closing of the merger is subject to the satisfaction of specified conditions, including obtaining clearance under the Hart-Scott-Rodino Antitrust Improvement Acts, and the approval of our unitholders and Enterprise's unitholders. Completion of the merger is expected to occur during the second half of 2004.

Our merger agreement with Enterprise limits our ability to raise additional capital prior to the closing of the merger without Enterprise's approval. In addition, because the closing of the merger will be a change of control, and thus a default, under our credit facility, we will either repay or amend that facility prior to the closing. In addition, because the merger closing will constitute a change of control under our indentures, we will be required to offer to repurchase our outstanding senior subordinated notes (and possibly our senior notes) at 101 percent of their principal amount after the closing. In coordination with Enterprise, we are evaluating alternative financing plans in preparation for the close of the merger. We and Enterprise can agree on the date of the merger closing after the receipt of all necessary approvals. We do not intend to close until appropriate financing is in place.

If the merger agreement is terminated and (1) a business transaction between us and a third party that conflicts with the merger was proposed and certain other conditions were met or (2) we materially and willfully violated our agreement not to solicit transactions that conflict with the merger, then we will be required to pay Enterprise a termination fee of $112 million. If the merger agreement is terminated because our unitholders did not approve the merger and either (1) a possible business transaction involving us but not involving Enterprise and conflicting with the merger was publicly proposed and our board of directors publicly and timely reaffirmed its recommendations of the Enterprise merger or (2) no such possible business transaction was publicly announced, then we will be required to pay Enterprise a termination fee of $15 million. Enterprise is subject to similar termination fee requirements.

Exchange with El Paso Corporation

In connection with our November 2002 San Juan assets acquisition, El Paso Corporation retained the obligation to repurchase the Chaco plant from us for $77 million in October 2021. In October 2003, we released El Paso Corporation from that obligation in exchange for El Paso Corporation contributing specified communication assets and other rights to us. The communication assets we received are used in the operation of our pipeline systems. Prior to the October 2003 exchange, we had access to these assets under our general and administrative services agreement with El Paso Corporation. We recorded the communication assets at El Paso Corporation's book value of $23.3 million with the offset to partners' capital.

As a result of the October 2003 exchange, we revised our estimate for the depreciable life of the Chaco plant from 19 to 30 years, the estimated remaining useful life of the Chaco plant. Depreciation expense will decrease approximately $0.5 million and $2.3 million on a quarter and annual basis.

Cameron Highway Oil Pipeline Company

Refer to Note 3 for a discussion related to our sale of a 50 percent interest in Cameron Highway Oil Pipeline.

San Juan Assets

In November 2002, we acquired from subsidiaries of El Paso Corporation, interests in assets we collectively refer to as the San Juan assets, which consist of the following:

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a 50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility, and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;
- 100 percent of the Typhoon Oil Pipeline assets located in the Deepwater Trend area of the Gulf of Mexico. Typhoon Oil was placed in service in July 2001 and provides transportation of oil produced from the Typhoon field for delivery to a platform in Green Canyon Block 19 with onshore access through various oil pipelines;
- 100 percent of the Typhoon Gas Pipeline, which was placed in service in August 2001. Typhoon Gas is also located in the Deepwater Trend area of the Gulf of Mexico. The pipeline gathers natural gas from the Typhoon field for redelivery into El Paso Corporation's ANR Patterson System; and
- 100 percent of the Coastal Liquids Partners' NGL Business, consisting of an integrated set of NGL assets that stretch from the Mexico border near McAllen, Texas, to Houston, Texas. This business includes a fractionation facility near Houston, Texas; a truck-loading terminal near McAllen, Texas, and leased underground NGL storage facilities.

We purchased the San Juan assets for $782 million, $764 million after adjustments for capital expenditures and actual working capital acquired. During 2003, the total purchase price and net assets acquired decreased $2.4 million due to post-closing purchase price adjustments related to natural gas imbalances, NGL in-kind reserves and well loss reserves. We financed the purchase of these assets with net proceeds from an offering of $200 million of $10\frac{5}{8}$% Senior Subordinated Notes due 2012; borrowings of $237.5 million under our senior secured acquisition term loan; our issuance, to El Paso Corporation, of 10,937,500 of our Series C units valued at $32 per unit or $350 million; and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

In connection with this acquisition, we entered into an agreement with El Paso Corporation under which El Paso Corporation would have been required, subject to specified conditions, to repurchase the Chaco plant from us for $77 million in October 2021, at which time we would have had the right to lease the plant from them for a period of 10 years with the option to renew the lease annually thereafter. In October 2003, we released El Paso Corporation from that repurchase obligation in exchange for El Paso Corporation contributing communication assets to us.

As a result of our acquisition of the San Juan assets, our financial results from the operation of the Chaco plant are significantly different from our results prior to the purchase in the following ways:

- We no longer receive fixed fee revenue of $0.134/Dth for natural gas processed; rather, from a majority of our customers, we receive a processing fee of an in-kind portion of the NGL produced from the natural gas processed. We then sell these NGL and, accordingly, our processing revenues are affected by changes in the price of NGL.
- We no longer receive revenue for leasing the Chaco plant to El Paso Field Services.
- We no longer recognize amortization expense relating to our investment in processing agreement, which we terminated upon completing the acquisition. This decrease in amortization expense is offset by additional depreciation expense associated with the acquired assets.

In accordance with our procedures for evaluating and valuing material acquisitions with El Paso Corporation, our Audit and Conflicts Committee engaged independent financial advisors. Separate financial advisors delivered fairness opinions for the acquisition of the San Juan assets and the issuance of the Series C units. Based on these opinions, our Audit and Conflicts Committee and the full Board approved these transactions.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At November 27, 2002
	(In thousands)
Note receivable	$ 17,100
Property, plant and equipment	763,696
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,766
Imbalances payable	17,403
Other current liabilities	2,565
Total liabilities assumed	19,968
Net assets acquired	$763,798

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we are amortizing to expense over the life of the contracts of approximately 4 years. We recorded adjustments to the purchase price of approximately $18 million primarily for capital expenditures and actual working capital acquired.

Our consolidated financial statements include the results of operations of the San Juan assets from the November 27, 2002 purchase date. We have included the assets and operating results of the El Paso Field Services' San Juan Gathering and Processing Businesses and the Typhoon Gas Pipeline in our natural gas pipelines and plants segment and the assets and operating results of the Typhoon Oil Pipeline and Coastal Liquids Partners' NGL Business in our oil and NGL logistics segment from the purchase date. The following selected unaudited pro forma financial information presents our consolidated operating results for the years ended December 31, 2002 and 2001 as if we acquired the San Juan assets on January 1, 2001:

	2002	2001
	(In thousands, except per unit amounts)	
Operating revenues	$627,191	$427,942
Income from continuing operations	$ 88,902	$ 77,219
Income allocated to common unitholders from continuing operations	$ 25,738	$ 16,687
Basic and diluted net income per unit from continuing operations	$ 0.60	$ 0.43

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

EPN Holding Assets

In April 2002, we acquired, through a series of related transactions, from subsidiaries of El Paso Corporation the following midstream assets located in Texas and New Mexico, which we collectively refer to, for purposes of these financial statements, as the EPN Holding assets:

- The Waha natural gas gathering and treating system and the Carlsbad natural gas gathering system which are generally located in the Permian Basin region of Texas and New Mexico.
- A 50 percent undivided interest in the Channel Pipeline System, an intrastate natural gas transmission system located along the Gulf Coast of Texas.
- The TPC Offshore pipeline system, a collection of natural gas gathering and transmission assets located offshore of Matagorda Bay, Texas, including the Oyster Lake and MILSP Condensate Separation and Stabilization facilities and other undivided interests in smaller pipelines.
- GulfTerra Texas Pipeline, L.P. which owned, among other assets, (i) the GulfTerra Texas intrastate pipeline system, (ii) the TGP natural gas lateral pipelines, (iii) the leased natural gas storage facilities located in Wharton County, Texas generally known as the Wilson Storage facility, (iv) an 80 percent undivided interest in the East Texas 36 inch pipeline, (v) a 50 percent undivided interest in the West Texas 30 inch pipeline, (vi) a 50 percent undivided interest in the North Texas 36 inch pipeline, (vii) the McMullen County natural gas gathering system, (viii) the Hidalgo County natural gas gathering system, (ix) a 22 percent undivided interest in the Bethel-Howard pipeline, and (x) a 75 percent undivided interest in the Longhorn pipeline.
- El Paso Hub Services L.L.C. which owned certain contract rights and parcels of real property located in Texas.
- 100 percent of the outstanding joint venture interest in Warwink Gathering and Treating Company which owned, among other assets, the Warwink natural gas gathering system located in the Permian Basin region of Texas and New Mexico.

In conjunction with the acquisition of the above assets, we obtained from another affiliate of El Paso Corporation, all of the equity interest in El Paso Indian Basin, L.P. which owned a 42.3 percent undivided, non-operating interest in the Indian Basin natural gas processing plant and treating facility located in southeastern New Mexico and the price risk management activities associated with the plant.

We acquired the EPN Holding assets to provide us with a significant new source of cash flow, greater diversification of our midstream asset base and to provide new long term internal growth opportunities in the Texas intrastate market. We purchased the EPN Holding assets for $750 million, adjusted for the assumption of $15 million of net working capital obligations related to natural gas imbalances resulting in net consideration of $735 million comprised of the following:

- $420 million of cash;
- $119 million of assumed short-term indebtedness payable to El Paso Corporation, which we subsequently repaid;
- $6 million in common units; and
- $190 million in assets, comprised of our Prince TLP and our nine percent overriding royalty interest in the Prince field (see discussion below).

During 2003, the purchase price and net assets acquired increased $17.5 million due to post-closing purchase price adjustments related primarily to a reduction in natural gas imbalance payables assumed in the transaction.

We entered into a limited recourse credit agreement with a syndicate of commercial banks to finance substantially all of the cash consideration associated with this transaction. See Note 6 for additional discussion regarding the EPN Holding term credit facility.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At April 8, 2002
	(In thousands)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we will amortize to expense using the units-of-production method over the expected lives of the underlying reserves ranging from 26 to 45 years. Additionally, we assumed environmental liabilities of $21.1 million for estimated environmental remediation costs associated with the GulfTerra Texas intrastate pipeline assets as discussed in Note 11.

Our consolidated financial statements include the results of operations of the EPN Holding assets from the April 8, 2002 purchase date. We have included the assets and operating results of the Waha, Carlsbad and Warwink natural gas gathering systems; the Channel and TPC Offshore pipeline systems; and the GulfTerra Texas pipeline assets (excluding the Wilson Storage facility) in our natural gas pipelines and plants segment. Our 42.3 percent ownership interest in the assets and operating results of the Indian Basin plant are included in our oil and NGL logistics segment and the Wilson storage facility assets and operating results are included in our natural gas storage segment. The following selected unaudited pro forma information depicts our consolidated results of operations for the years ended December 31, 2002 and 2001 as if we acquired the EPN Holding assets on January 1, 2001:

	2002	2001
	(In thousands, except per unit amounts)	
Operating revenues	$540,154	$538,095
Income from continuing operations	$114,517	$ 81,022
Income allocated to common unitholders from continuing operations	$ 56,020	$ 38,874
Basic and diluted net income per unit from continuing operations	$ 1.31	$ 1.13

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

Prince Assets

In connection with our April 2002 acquisition of the EPN Holding assets from El Paso Corporation, we sold our Prince tension leg platform (TLP) and our nine percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation. The results of operations for these assets have been accounted for as discontinued operations and have been excluded from continuing operations for all periods in our consolidated statements of income. Accordingly, the segment results in Note 15 reflect neither the results of operations for the Prince assets nor the related net assets held for sale. The Prince TLP was previously included in the platform services segment and related royalty interest was included in non-segment activity. Included in income from discontinued operations for the years ended December 31, 2002 and 2001 were revenues of $7.8 million and $8.8 million attributable to these disposed assets.

In April 2002, we sold the Prince assets for $190 million and recognized a gain on the sale of $0.4 million during 2002. In conjunction with this transaction, we repaid the related outstanding $95 million principal balance under our Argo term loan.

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately $81 million, consisting of $26 million cash and $55 million of assumed indebtedness, and at the acquisition date also repaid all of Deepwater Holdings' $110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we acquired interests in the title holder of, and other interests in the Chaco cryogenic natural gas processing plant for $198.5 million. The total purchase price was composed of a payment of $77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of $121.5 million to El Paso Field Services in connection with the execution of a 20-year fee-based processing agreement relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we received a fixed fee for each dekatherm of natural gas that we processed at the Chaco plant, and we bore all costs associated with the plant's ownership and operations. El Paso Field Services personnel continued to operate the plant. In accordance with the original construction financing agreements, the Chaco plant was under an operating lease to El Paso Field Services. El Paso Field Services had the right to repurchase the Chaco plant at the end of the lease term in October 2002 for approximately $77 million. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

Since the Chaco transaction was an asset acquisition, we have assigned the total purchase price to property, plant and equipment and investment in processing agreement. Since the Deepwater Holdings transaction was an acquisition of additional interests in a business, we are providing summary information related to the acquisition of Deepwater Holdings in the following table (in thousands):

Fair value of assets acquired	$ 81,331
Cash acquired	5,386
Fair value of liabilities assumed	(60,917)
Net cash paid	$ 25,800

In connection with our acquisition of the San Juan assets in November 2002, the original terms of the processing, lease and operating agreements between the Chaco plant and El Paso Field Services were terminated. The effect on our operation of the Chaco plant resulting from our acquisition of the San Juan assets is discussed above.

GTM Texas (formerly EPN Texas)

In February 2001, we acquired GTM Texas from a subsidiary of El Paso Corporation for $133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 500 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGL into ethane, propane, butane and natural gasoline products that are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of GTM Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 2001, as if we acquired GTM Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2001:

	2001
	(In thousands, except per unit amounts)
Operating revenues	$269,681
Operating income	$101,406
Net income allocated to limited partners	$ 39,157
Basic and diluted net income per unit	$ 1.14

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately $163 million consisting of approximately $109 million for the assets we sold and approximately $54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately $12 million, and Deepwater Holdings recognized losses of approximately $21 million. Our share of Deepwater Holdings' losses was approximately $14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying 2001 consolidated statement of income.

As additional consideration for the above transactions, El Paso Corporation agreed to make payments to us totaling $29 million. These payments were made in quarterly installments of $2.25 million for three years beginning in 2001 and we will receive the final payment of $2 million in the first quarter of 2004. From this additional consideration, we realized income of approximately $25 million in the first quarter of 2001, which has been reflected in other income in the accompanying 2001 consolidated statement of income.

3. Investments in Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2003, the carrying amount of our equity investments exceeded the underlying equity in net assets by approximately $3.0 million, which is included in our oil and NGL logistics segment. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount, refer to Note 1, Summary of Significant Accounting Policies, Goodwill and Other Intangible Assets. Summarized financial information for these investments is as follows:

	As of or for the Year Ended December 31, 2003				
	Coyote	Deepwater Gateway[(c)]	Cameron Highway[(c)]	Poseidon	Total
			(In thousands)		
End of period ownership interest	50%	50%	50%	36%	
Operating results data:					
Operating revenues	$ 7,200	$ —	$ —	$ 41,293	
Other income	7	47	37	56	
Operating expenses	(355)	—	—	(3,694)	
Depreciation	(1,381)	—	—	(8,316)	
Other expenses	(736)	(31)	(171)	(6,313)	
Net income (loss)	$ 4,735	$ 16	$ (134)	$ 23,026	
Our share:					
Allocated income (loss)	$ 2,368	$ 8	$ (67)	$ 8,289	
Adjustments[(a)]	9	(8)	67	(191)	
Earnings from unconsolidated affiliate	$ 2,377	$ —	$ —	$ 8,098	$11,373[(b)]
Allocated distributions	$ 3,500	$ —	$ —	$ 8,640	$12,140
Financial position data:					
Current assets	$ 987	$ 8,271	$ 53,644	$ 98,937	
Noncurrent assets	31,897	230,825	266,554	218,893	
Current liabilities	34,784	18,294	26,332	91,146	
Noncurrent liabilities	—	155,000	125,000	123,000	

(a) We recorded adjustments primarily for differences from estimated earnings reported in our Annual Report on our Form 10-K and actual earnings reported in the unaudited financial statements of our unconsolidated affiliates.

(b) Total earnings from unconsolidated affiliates includes a $898 thousand gain associated with the sale of our interest in Copper Eagle.

(c) Cameron Highway Oil Pipeline Company and Deepwater Gateway, L.L.C. are development stage companies; therefore there are no operating revenues or operating expenses to provide operational results. Since their formations, they have incurred organizational expenses and received interest income.

Cameron Highway. In June 2003, we formed Cameron Highway Oil Pipeline Company and contributed to this newly formed company the $458 million Cameron Highway oil pipeline system construction project. Cameron Highway is responsible for building and operating the pipeline, which is scheduled for completion during the fourth quarter of 2004. We entered into producer agreements with three major anchor producers, BP Exploration & Production Company, BHP Billiton Petroleum (Deepwater), Inc., and Union Oil Company of California, which agreements were assigned to and assumed by Cameron Highway. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline.

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero Energy Corporation for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project. In July 2003, we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us $5 million once the system is completed and another $11 million by the end of 2006. We expect to reflect the receipts of these additional amounts in the periods received as gains from the sale of long-lived assets in our statement of income. In connection with the formation of the Cameron Highway joint venture, Valero agreed to pay their proportionate share of pipeline construction costs that exceed Cameron Highway's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

The Cameron Highway oil pipeline system project is expected to be funded with 37 percent equity, or $169 million through capital contributions from us and Valero, the two Cameron Highway partners, which contributions have already been made, and 63 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. See Note 6 for additional discussion of the project loan facility. As of December 31, 2003, Cameron Highway has spent approximately $256 million (of which $85 million constituted equity contributions by us) related to this pipeline, which is in the construction stage. We and Valero are obligated to make additional capital contributions to Cameron Highway if and to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including initial equity contributions and proceeds from Cameron Highway's project loan facility.

Deepwater Gateway. As of December 31, 2003, we have contributed $33 million, as our 50 percent share, to Deepwater Gateway, which amount satisfies our initial equity funding requirement related to the Marco Polo TLP. We expect that the remaining costs associated with the Marco Polo TLP will be funded through the $155 million project finance loan and Deepwater Gateway's members' contingent equity obligations (of which our share is $14 million). This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. The loan agreement requires Deepwater Gateway to maintain a debt service reserve equal to six months' interest. Other than that debt service reserve and any other reserve amounts agreed upon by more than 66.7 percent majority interest of Deepwater Gateway's members, Deepwater Gateway will (after the project finance loan is either repaid or converted into a term loan) distribute any available cash to its members quarterly. Deepwater Gateway is not currently generating income or cash flow. Deepwater Gateway is managed by a management committee consisting of representative from each of its members.

Front Runner Oil Pipeline. In September 2003, we announced that Poseidon, our 36 percent owned joint venture, entered into an agreement for the purchase and sale of crude oil from the Front Runner Field. Poseidon will construct, own and operate the $28 million project, which will connect the Front Runner platform with Poseidon's existing system at Ship Shoal Block 332. The new 36-mile, 14-inch pipeline is expected to be operational by the third quarter of 2004 and have a capacity of 65 MBbls/d. As Poseidon expects to fund Front Runner's capital expenditures from its operating cash flow and from its revolving credit facility, we do not expect to receive distributions from Poseidon until the Front Runner oil pipeline is completed.

	As of or for the Year Ended December 31, 2002			
	Coyote[(a)]	Poseidon	Deepwater Gateway[(b)]	Total
	(In thousands)			
End of period ownership interest	50%	36%	50%	
Operating results data:				
Operating revenues	$ 635	$ 54,261	$ —	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	—	
Depreciation	(110)	(8,356)	—	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	$ 414	$ 60,986	$ (214)	
Our share:				
Allocated income (loss)	$ 207	$ 21,955	$ (107)	
Adjustments[(c)]	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	$ 194	$ 13,445	$ —	$13,639
Allocated distributions	$ 2,000	$ 15,804	$ —	$17,804
Financial position data:				
Current assets	$ 1,575	$ 152,784	$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	—	148,000	27,000	

(a) We acquired an interest in Coyote Gas Treating, L.L.C. in November 2002 as part of the San Juan assets acquisition.

(b) In June 2002, we formed Deepwater Gateway, L.L.C., a 50/50 joint venture with Cal Dive International, Inc., to construct and install the Marco Polo TLP. Also in August 2002, Deepwater Gateway obtained a project finance loan to fund a substantial portion of the cost to construct the Marco Polo TLP. For further discussion of this project loan, see Note 6, Financing Transactions. Deepwater Gateway, L.L.C. is a development stage company; therefore there are no operating revenues or operating expenses to provide operational results. Since Deepwater Gateway's formation in 2002, it has incurred organizational expenses and received interest income.

(c) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on our Form 10-K and actual earnings recorded in the audited annual reports of our unconsolidated affiliates. The adjustment for Poseidon primarily represents the receipt of proceeds from a favorable litigation related to the January 2000 pipeline rupture.

	As of or for the Year Ended December 31, 2001				
	Deepwater Holdings[(a)]	Poseidon	Divested Investments[(b)]	Other[(c)]	Total
			(In thousands)		
End of period ownership interest	100%	36%	—	50%	
Operating results data:					
Operating revenues	$ 40,933	$ 70,401	$1,982	$145	
Other income (loss)	—	394	(85)	—	
Operating expenses	(16,740)	(1,586)	(590)	(73)	
Depreciation	(8,899)	(10,552)	(953)	—	
Other (expenses) income	(5,868)	(7,668)	222	(22)	
Loss on sale of assets	(21,453)	—	—	—	
Net income (loss)	$(12,027)	$ 50,989	$ 576	$ 50	
Our share:					
Allocated income (loss)[(d)]	$ (9,925)	$ 18,356	$ 148	$ 25	
Adjustments[(e)]	—	(146)	(9)	—	
Earnings (loss) from unconsolidated affiliates	$ (9,925)	$ 18,210	$ 139	$ 25	$ 8,449
Allocated distributions	$ 12,850	$ 22,212	$ —	$ —	$35,062
Financial position data:					
Current assets		$ 91,367		$177	
Noncurrent assets		226,570		—	
Current liabilities		80,365		33	
Noncurrent liabilities		150,000		—	

(a) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. Deepwater Holdings sold its interest in its UTOS subsidiary in April 2001. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings and as a result of this transaction, from the acquisition date Deepwater Holdings is consolidated in our financial statements. The information presented for Deepwater Holdings as an equity investment is through October 18, 2001.

(b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

(c) Through October 2001 this company processed gas for Deepwater Holdings' Stingray subsidiary. This agreement was terminated in October 2001, and as of this date there are no operations related to this investment.

(d) The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' $21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately $14 million.

(e) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on Form 10-K and actual earnings reported in the audited annual reports of our unconsolidated affiliates.

4. Property, Plant and Equipment

Our property, plant and equipment consisted of the following:

	December 31, 2003	December 31, 2002
	(In thousands)	
Property, plant and equipment, at cost[(1)]		
Pipelines	$2,487,102	$2,317,503
Platforms and facilities	121,105	128,582
Processing plants	305,904	300,897
Oil and natural gas properties	131,100	127,975
Storage facilities	337,535	331,562
Construction work-in-progress	383,640	177,964
	3,766,386	3,384,483
Less accumulated depreciation, depletion and amortization	871,894	659,545
Total property, plant and equipment, net	$2,894,492	$2,724,938

(1) Includes leasehold acquisition costs with an unamortized balance of $3.2 million and $4.1 million at December 31, 2003 and 2002. One interpretation being considered relative to SFAS No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Intangible Assets* is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on our consolidated balance sheets. We will continue to include these costs in property, plant, and equipment until further guidance is provided.

Due to the sale of our interest in the Manta Ray Offshore system in January 2001, we lost a primary connecting point to our Manta Ray pipeline. As a result, we abandoned the Manta Ray pipeline and recorded an impairment of approximately $3.9 million in the first quarter of 2001 which is reflected in the natural gas pipelines and plants segment.

5. Investment in Processing Agreement

As part of our October 2001 Chaco transaction, we paid $121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. The processing agreement was being amortized on a straight-line basis over the life of the agreement and we recorded amortization expense of $5.6 million in 2002 and $1.5 million in 2001 related to this asset. As a result of the San Juan acquisition in November 2002, we now own the gathering system and related facilities previously owned by El Paso Field Services, including the rights of El Paso Field Services under the arrangements relating to the Chaco plant. As part of the San Juan acquisition, the processing agreement was terminated.

6. Financing Transactions

Credit Facility

Our credit facility consists of two parts: the revolving credit facility maturing in 2006 and a senior secured term loan maturing in 2008. Our credit facility is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 16, and are collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries). The interest rates we are charged on our credit facility are determined at our option using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) LIBOR. The interest rate we are charged is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's. The interest we are charged would increase by 0.25% if the credit ratings on our senior secured credit facility decrease or our leverage ratio decreases, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. Additionally, we pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.30% to 0.50%.

Our credit facility contains covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders. The financial covenants associated with our credit facility are as follows:

(a) The ratio of consolidated EBITDA, as defined in our credit agreements, to consolidated interest expense cannot be less than 2.0 to 1.0;

(b) The ratio of consolidated total senior indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 3.25 to 1.0; and

(c) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0.

Among other things, our credit agreement includes as an event of default a change of control, defined as the failure of El Paso Corporation and its subsidiaries to no longer own at least 50 percent of our general partner. We are in compliance with the financial ratios and covenants contained in each of our credit facilities at December 31, 2003.

Revolving Credit Facility

In September 2003, we renewed our revolving credit facility to, among other things, expand the credit available from $600 million to $700 million and extend the maturity from May 2004 to September 2006.

At December 31, 2003, we had $382 million outstanding under our revolving credit facility at an average interest rate of 3.17%. We may elect that all or a portion of the revolving credit facility bear interest at either the variable rate described above increased by 1.0% or LIBOR increased by 2.0%. The total amount available to us at December 31, 2003, under this facility was $318 million.

Senior Secured Term Loan

In December 2003, we refinanced the term loan portion of our credit facility to provide greater financial flexibility by, among other things, expanding the existing term component from $160 million to $300 million, extending the maturity from October 2007 to December 2008, reducing the semi-annual payments from $2.5 million to $1.5 million and reducing the interest rate we are charged by 1.25%. We used the proceeds from the term loan to repay the $155 million outstanding under the initial term loan and to temporarily reduce amounts outstanding under our revolving credit facility. We charged $2.8 million to interest and debt expense in December 2003 to write-off unamortized debt issuance costs associated with the initial term loan.

The senior secured term loan is payable in semi-annual installments of $1.5 million in June and December of each year for the first nine installments and the remaining balance at maturity in December 2008. We may elect that all or a portion of the senior secured term loan bear interest at either 1.25% over the variable base rate discussed above; or LIBOR increased by 2.25%. As of December 31, 2003, we had $300 million outstanding with an average interest rate of 3.42%.

GulfTerra Holding Term Credit Facility (formerly EPN Holding Term Credit Facility)

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a $560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the GulfTerra Holding term loan) of $535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the GulfTerra Holding revolving credit facility) of up to $25 million to finance EPN Holding's working capital. At the time of its acquisition, EPN Holding borrowed $535 million ($531 million, net of issuance costs) under this term loan and had $25 million available under the GulfTerra Holding revolving credit facility. We used net proceeds of approximately $149 million from our April 2002 common unit offering, $0.6 million contributed by our general partner to maintain its one percent capital account balance and $225 million of the net proceeds from our May 2002 offering of 8½% Senior Subordinated Notes to reduce indebtedness under the term loan. In July 2003, we repaid the remaining $160 million balance of this term credit facility with proceeds from our issuance of $250 million 6¼% senior notes due 2010. We recognized a loss of $1.2 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility.

Senior Secured Acquisition Term Loan

As part of our November 2002 San Juan assets acquisition, we entered into a $237.5 million senior secured acquisition term loan to fund a portion of the purchase price. We repaid this senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million 8½% senior subordinated notes due 2010. We recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs in connection with our repayment of this facility. From the issuance of the senior secured acquisition term loan in November 2002 to its repayment date, the interest rates on our revolving credit facility and GulfTerra Holding term credit facility were 2.25% over the variable base rate described above or LIBOR increased by 3.50%.

Argo Term Loan

This loan with a balance of $95 million, including current maturities, at December 31, 2001, was repaid in full in April 2002, in connection with the EPN Holding assets acquisition.

Senior Notes

In July 2003, we issued $250 million in aggregate principal amount of 6¼% senior notes due June 2010. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay $160 million of indebtedness under the GulfTerra Holding term credit facility and to temporarily repay $85.1 million of the balance outstanding under our revolving credit facility. The interest on our senior notes is payable semi-annually in June and December with the principal maturing in June 2010. Our senior notes are unsecured obligations that rank senior to all our existing and future subordinated debt and equally with all of our existing and future senior debt, although they are effectively junior in right of payment to all of our existing and future senior secured debt to the extent of the collateral securing that debt. Our senior notes are guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries.

We may redeem some or all of our senior notes, at our option, at any time with at least 30 days notice at a price equal to the greater of (1) 100 percent of the principal amount plus accrued interest, or (2) the sum of the present value of the remaining scheduled payments plus accrued interest.

Senior Subordinated Notes

Each issue of our senior subordinated notes is subordinated in right of payment to all of our existing and future senior debt, including our existing credit facility and the senior notes we issued in July 2003.

In March 2003, we issued $300 million in aggregate principal amount of 8½% senior subordinated notes. The interest on these notes is payable semi-annually in June and December, and the notes mature in June 2010. We used the proceeds of approximately $293.5 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility. We may, at our option, prior to June 1, 2006, redeem up to 33 percent of the originally issued aggregate principal amount of these notes at a redemption price of 108.50 percent of the principal amount, and in December 2003, we redeemed $45 million under this provision (see discussion below). We may redeem all or part of the remainder of these notes at any time on or after June 1, 2007. The redemption price on that date is 104.25 percent of the principal amount, declining annually until it reaches 100 percent of the principal amount.

In November 2002, we issued $200 million in aggregate principal amount of 10⅝% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in December 2012. These notes were issued for $198 million, net of discount of $1.5 million to yield 10.75% (proceeds of $194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%, and in December 2003, we redeemed $66 million under this provision (see discussion below). On or after December 1, 2007, we may redeem all or part of the remainder of these notes at 105.313% of the principal amount.

In May 2002, we issued $230 million in aggregate principal amount of 8½% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature June 2011. The Senior Subordinated Notes were issued for $234.6 million (proceeds of approximately $230 million, net of issuance costs). We used proceeds of $225 million to reduce indebtedness under our EPN Holding term credit facility and the remainder for general partnership purposes. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $75.9 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 2001, we issued $250 million in aggregate principal amount of 8½% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately $243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%, and in December 2003, we redeemed $82.5 million under this provision (see discussion below). On or after June 1, 2006, we may redeem all or part of the remainder of these notes at 104.250% of the principal amount.

In May 1999, we issued $175 million in aggregate principal amount of 10⅜% Senior Subordinated Notes. The interest on these notes is payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately $169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. On or after June 1, 2004, we may redeem all or part of these notes at 105.188% of the principal amount.

Our subsidiaries, except GulfTerra Energy Partners Finance Corporation and our unrestricted subsidiaries, have guaranteed our obligations under the senior notes and all of the issuances of senior subordinated notes described above. In addition, we could be required to repurchase the senior notes and senior subordinated notes if certain circumstances relating to change of control or asset dispositions exist.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½%

senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of $8\frac{1}{2}$%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. At December 31, 2003, the fair value of the swap was a liability, included in non-current liabilities, of approximately $7.4 million. The fair value of the hedged debt decreased by the same amount.

In December 2003, we used a portion of the net proceeds from our October 2003 equity offerings to redeem approximately $269.4 million in principal amount of our senior subordinated notes. The terms of our indentures allow us to use proceeds from an equity offering, within a 90 day period after the offering, to redeem up to 33 percent of the principal during the first three years the notes are outstanding. We incurred additional costs totaling $29.1 million resulting from the payment of the redemption premiums and the write-off of unamortized debt issuance costs, premiums and discounts. We accounted for these costs as an expense during the fourth quarter of 2003 in accordance with the provisions of SFAS No. 145.

In March 2004, we gave notice to exercise our right, under the terms of our senior subordinated notes' indentures, to repay, at a premium, approximately $39.1 million in principal amount of those senior subordinated notes. The indentures provide that, within 90 days of an equity offering, we can call up to 33 percent of the original face amount at a premium. The amount we can repay is limited to the net proceeds of the offering. We will recognize additional costs totaling $4.1 million resulting from the payment of the redemption premiums and the writeoff of unamortized debt issuance costs. We will account for these costs as an expense during the second quarter of 2004 in accordance with the provisions of SFAS No. 145.

Restrictive Provisions of Senior and Senior Subordinated Notes

Our senior and senior subordinated notes include provisions that, among other things, restrict our ability and the ability of our subsidiaries (excluding our unrestricted subsidiaries) to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies, and enter into sale and lease-back transactions, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries in addition to restricting our ability to make distributions to our unitholders. Many restrictive covenants associated with our senior notes will effectively be removed following a period of 90 consecutive days during which they are rated Baa3 or higher by Moody's or BBB— or higher by S&P, and some of the more restrictive covenants associated with some (but not all) of our senior subordinated notes will be suspended should they be similarly rated.

Other Credit Facilities

Poseidon

As of December 31, 2003, Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, was party to a $185 million credit agreement under which it had $123 million outstanding at December 31, 2003.

In January 2004, Poseidon amended its credit agreement and decreased the availability to $170 million. The amended facility matures in January 2008. The outstanding balance from the previous facility was transferred to the new facility.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of the $123 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.25% over the LIBOR rate resulting in an effective interest rate of 4.74% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility are dependent on its leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2003 was LIBOR plus 1.25% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.25% for Base Rate loans. As of December 31, 2003, the remaining $48 million was at an average interest rate of 2.46%.

Under its amended credit facility, based on Poseidon's leverage ratio for the year ended December 31, 2003, Poseidon's interest rate is LIBOR plus 2.00% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 1.00% for Base Rate loans. Poseidon's interest rates will decrease by 0.25% if their leverage ratio declines to 3.00 to 1.00 or less, by 0.50% if their leverage ratio declines to 2.00 to 1.00 or less, or by 0.625% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires Poseidon to maintain a debt service reserve equal to two times the previous quarters' interest.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, restrictions on liens collateralizing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of Poseidon's debt and other financial obligations.

Under the Poseidon $170 million revolving credit facility, the financial debt covenants are:

(a) Poseidon must maintain consolidated tangible net worth in an amount not less than $75 million plus 100% of the net cash proceeds from the issuance by Poseidon of equity securities of any kind;

(b) the ratio of Poseidon's EBITDA, as defined in Poseidon's credit agreement, to interest expense paid or accrued during the four quarters ending on the last day of the current quarter must be at least 2.50 to 1.00; and

(c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 4.50 to 1.00 in 2004, 3.50 to 1.00 in 2005 and 3.00 to 1.00 thereafter.

Poseidon was in compliance with the above covenants and the covenants under its previous facility as of December 31, 2003.

Deepwater Gateway

In August 2002, Deepwater Gateway, our joint venture that is constructing the Marco Polo TLP, obtained a $155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either (i) LIBOR plus 1.75% or (ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets. If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to $22.5 million. As of December 31, 2003, Deepwater Gateway had $155 million outstanding under the project finance loan at an average interest rate of 2.94% and had not paid us or any of our subsidiaries any distributions.

This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the project finance loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. In addition, Deepwater Gateway is prohibited from making distributions until the project finance loan has been repaid or is converted.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest (See Note 3 for additional discussion relating to the formation of Cameron Highway), entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes, each of which fund proportionately as construction costs are incurred.

The $225 million construction loan bears interest at Cameron Highway's option at each borrowing at either (i) 2.00% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) 3.00% over LIBOR. Upon completion of the construction, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly principal payments of $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable. At December 31, 2003, Cameron Highway had $69 million outstanding under the construction loan at an average interest rate of 4.21%.

The interest rate on Cameron Highway's senior secured notes is 3.25% over the rate on 10-year U.S. Treasury securities. Principal payments of $4 million are due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013. At December 31, 2003, Cameron Highway had $56 million outstanding under the notes at an average interest rate of 7.38%.

Under the terms of its project loan facility, Cameron Highway must pay each of the lenders and the senior secured noteholders commitment fees of 0.5% per year on any unused portion of such lender's or noteholder's committed funds. The project loan facility as a whole is collateralized by (1) substantially all of Cameron Highway's assets, including, upon conversion, a debt service reserve capital account, and (2) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, as discussed in Note 3, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Debt Maturity Table

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

2004	$ 3,000
2005	3,000
2006	385,000
2007	3,000
2008	288,000
Thereafter	1,135,600
Total long-term debt and other financing obligations, including current maturities	$1,817,600

Interest and Debt Expense

We recognized the interest cost incurred in connection with our financing transactions as follows for each of the years ended December 31:

	2003	2002	2001
		(In thousands)	
Interest expense incurred	$140,282	$87,522	$ 54,885
Interest capitalized	(12,452)	(5,571)	(11,755)
Net interest expense	127,830	81,951	43,130
Less: Interest expense on discontinued operations	—	891	1,588
Net interest expense on continuing operations	$127,830	$81,060	$ 41,542

Loss Due to Early Redemptions of Debt

We recognized losses associated with early redemptions of debt as follows for each of the years ended December 31:

	2003	2002
	(In thousands)	
Loss due to payment of redemption premiums	$24,302	$ —
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	12,544	2,434
	$36,846	$2,434

7. Financial Instruments

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Liabilities:				
Revolving credit facility	$382.0	$382.0	$491.0	$491.0
GulfTerra Holding term credit facility	—	—	160.0	160.0
Senior secured term loan	300.0	300.0	160.0	160.0
Senior secured acquisition term loan	—	—	237.5	237.5
$10^3/_8$% senior subordinated notes	175.0	189.9	175.0	186.4
$8^1/_2$% senior subordinated notes[(1)]	167.5	188.4	250.0	233.1
$8^1/_2$% senior subordinated notes[(1)]	156.6	173.4	234.3	214.5
$10^5/_8$% senior subordinated notes	133.1	165.5	198.5	205.5
$8^1/_2$% senior subordinated notes	255.0	290.7	—	—
$6^1/_4$% senior notes	250.0	262.5	—	—
Non-trading derivative instruments				
Commodity swap and forward contracts	$ 9.0	$ 9.0	$ 4.7	$ 4.7
Interest rate swap	7.4	7.4	—	—

(1) Excludes market value of interest rate swap, see interest rate swap discussion below.

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

	2003			2002		
	Notional Volume		Maximum	Notional Volume		Maximum
	Buy	Sell	Term in Years	Buy	Sell	Term in Years
Commodity						
Natural Gas (MDth)	85	10,980	<1	95	10,950	<1
NGL (MBbl)	—	1,644	<1	—	—	—

In July 2003, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%.

As of December 31, 2003, and 2002, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because the variable interest rates on these loans reprice frequently to reflect currently available interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments from prices indicated for the same or similar commodity transactions for a specific index.

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of our customers' failure to pay. Our customers are concentrated in the energy sector, and the creditworthiness of several industry participants have been called into question. We maintain credit policies to minimize overall credit risk. We monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. Partners' Capital

General

As of December 31, 2003, we had 58,404,649 common units outstanding. Common units totaling 48,020,404 are owned by the public, representing an 82.2 percent common unit interest in us. As of December 31, 2003, El Paso Corporation, through its subsidiaries, owned 10,384,245 common units, or 17.8 percent of our outstanding common units, all of our 10,937,500 Series C units and 50 percent of our one percent general partner interest.

Offering of Common Units

During 2003, we issued the following common units in public offerings:

Offering Date	Common Units Issued	Public Offering Price	Net Offering Proceeds
		(per unit)	(in thousands)
October 2003	4,800,000	$40.60	$186.1
August 2003	507,228	$39.43	$ 19.7
June 2003	1,150,000	$36.50	$ 40.3
May 2003[(1)]	1,118,881	$35.75	$ 38.3
April 2003	3,450,000	$31.35	$103.1

(1) Offering includes 80 Series F convertible units offered. Refer to description below.

In addition to our public offerings of common units, in October 2003, we sold 3,000,000 common units privately to Goldman Sachs in connection with their purchase of a 9.9 percent membership interest in our general partner. We used the net proceeds of $111.5 million from that private sale and the net proceeds from the other common unit public offerings to temporarily reduce amounts outstanding under our revolving credit facility, senior subordinated notes, and for general partnership purposes.

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to a large institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until the date we merge with Enterprise (subject to other defined extension rights). The Series F2 units are convertible into up to $40 million of common units. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of (i) the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75, or (ii) the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). The price at which the Series F convertible units could have been converted to common units, assuming we had received a conversion notice on December 31, 2003 and March 2, 2004, was $40.38 and $39.40. The Series F convertible units may be converted into a maximum of 8,329,679 common units. Holders of Series F convertible units are not entitled to vote or receive distributions. The $4.1 million value associated with the Series F convertible units is included in partners' capital as a component of common units capital.

In August 2003, we amended the terms of the Series F convertible units to permit the holder to elect a "cashless" exercise — that is, an exercise where the holder gives up common units with a value equal to the exercise price rather than paying the exercise price in cash. If the holder so elects, we have the option to settle the net position by issuing common units or, if the settlement price per unit is above $26.00 per unit, paying the holder an amount of cash equal to the market price of the net number of units. These amendments had no effect on the classification of the Series F convertible units on the balance sheet at December 31, 2003.

In the first quarter of 2004, 45 Series F1 convertible units were converted into 1,146,418 common units, for which the holder of the convertible units paid us $45 million.

Any Series F convertible units outstanding at the merger date will be converted into rights to receive Enterprise common units, subject to the restrictions governing the Series F units. The number of Enterprise common units and the price per unit at conversion will be adjusted based on the 1.81 exchange ratio.

In connection with the offerings in 2003, our general partner contributed to us approximately $2.0 million of our Series B preference units and cash of $3.1 million in order to maintain its one percent general partner interest.

In April 2002, we completed simultaneous offerings of 4,083,938 common units, which included a public offering of 3,000,000 common units and a private offering, at the same unit price, of 1,083,938 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $149 million to reduce indebtedness under EPN Holding's term credit facility. Also in April 2002, we issued in a private offering 159,497 common units at the then-current market price of $37.74 per unit to a subsidiary of El Paso Corporation as partial consideration for our acquisition of the EPN Holding assets. In addition, our general partner contributed approximately $0.6 million in cash to us in April 2002 in order to maintain its one percent capital account balance.

In October 2001, we completed simultaneous offerings of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately $212 million to redeem 44,608 of our Series B preference units for their liquidation value of $50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $2.1 million in cash to us in order to satisfy its one percent contribution requirement.

In March 2001, we completed a public offering of 2,250,000 common units. We used the net cash proceeds of $66.6 million from the offering to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed $0.7 million to us in order to satisfy its one percent capital contribution requirement.

Series B Preference Units

In August 2000, we issued 170,000 Series B preference units with a value of $170 million to acquire the Petal and Hattiesburg natural gas storage businesses. In October 2001, we redeemed 44,608 of the Series B preference units for $50 million liquidation value including accrued distributions of approximately $5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2002, the liquidation value of the outstanding Series B preference units was approximately $158 million. In October 2003, we redeemed all 123,865 of our remaining outstanding Series B preference units for $156 million, a 7 percent discount from their liquidation value of $167 million. For this redemption, we used borrowings under our revolving credit facility. We reflected the discount as an increase to the common units capital, Series C units capital and to our general partner's capital accounts.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of $32 per unit, $350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1993 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of the Series C units has the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit can convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. In addition, our general partner contributed $3.5 million to us in order to satisfy its one percent capital contribution requirement. The holder of the Series C units has thus far not requested a vote to convert the Series C units into common units. As part of the proposed merger with Enterprise, Enterprise will purchase from a subsidiary of El Paso Corporation all of our outstanding Series C units. These units will not be converted to Enterprise common units in the merger but rather will remain limited partnership interests in GulfTerra after the closing of the merger transaction and, as such interest, will lose their GulfTerra common unit conversion and distribution rights.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in the partnership agreement, to our unitholders and to our general partner. Available cash generally consists of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves for any proper partnership purpose. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of our agreements or obligations.

Cash distributions on common units, Series C units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly distributions. The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the year ended December 31, 2003:

Month Paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(Per unit)		(In millions)	
February	$0.675	$29.7	$ 7.4	$15.0
May	$0.675	$32.0	$ 7.4	$15.9
August	$0.700	$34.8	$ 7.7	$18.0
November	$0.710	$41.4	$ 7.8	$21.2

In January 2004, we declared a cash distribution of $0.71 per common and Series C unit, $49.3 million in aggregate, for the quarter ended December 31, 2003, which we paid on February 14, 2004. In addition, we paid our general partner $21.3 million related to its general partner interest. At the current distribution rates, our general partner receives approximately 30.2 percent of our total cash distributions for its role as our general partner.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances. No grants of unit options were made in 2002. During 2003, under our Omnibus Plan, we granted 17,500 unit options, 25,000 time-vested restricted units and will grant 25,000 restricted units, if certain performance targets are achieved, to employees of El Paso Field Services whose primary responsibilities are the commercial management of our assets.

In August 1998, we also adopted the 1998 Common Unit Plan for Non-Employee Directors (Director Plan), formerly the 1998 Unit Option Plan for Non-Employee Directors, to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of Directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman may designate. During 2003, under the Director Plan, we granted 5,226 restricted units at a fair value per unit of $36.37 and 10,500 unit options with a grant price of $35.92. Restricted units awards representing 5,429 and 4,090 were granted during 2002 and 2001 with a fair value of $32.23 and $33.00 per unit. As of December 31, 2003, 12,292 restricted units were outstanding.

We have accounted for all of these unit options and restricted units, except for the unit options issued to non-employee directors, in accordance with SFAS No. 123. Under SFAS No. 123, we report the fair value of these issuances as deferred compensation. Deferred compensation is amortized to compensation expense over the respective vesting or performance period. We have accounted for the unit options issued to the non-employee directors of our general partner's Board of Directors in accordance with APB No. 25.

We issued time-vested restricted units and the performance-based restricted units at fair value at their date of grant. The restrictions on the time-vested units will lapse in four years from the date of grant. The restrictions on the performance-based restricted units will lapse if we achieve a specified level of target performance for identified "greenfield" projects by June 1, 2007 (for the 15,000 performance-based restricted units issued in June 2003) and by August 1, 2007 (for the 10,000 performance-based restricted units issued in August 2003). If we do not reach those targets by the applicable dates, the performance-based units will be forfeited. We will amortize the fair value of the time-vested restricted units over their four-year restricted period and the fair value of the performance-based restricted units over their performance periods. The performance-based restricted units are not entitled to vote or to receive distributions, until after (and if) we achieve specified level of target performance. The restricted units issued to non-employee directors of our general partner's Board of Directors were issued at fair value at their date of grant. This fair value is being amortized to compensation expense over the period of service, which we have estimated to be one year.

Total unamortized deferred compensation as of December 31, 2003 and 2002 was approximately $1.5 million and $1.2 million. Our 2001 deferred compensation is fully amortized. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1 percent to our general partner and 99 percent to our limited partners.

The following table summarizes activity under the Omnibus Plan and Director Plan (excluding our restricted units) as of and for the years ended December 31, 2003, 2002 and 2001.

	2003		2002		2001	
	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price	# Units of Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of year	1,550,000	$32.17	1,614,500	$32.09	925,500	$27.15
Granted	28,000	35.08	8,000	32.23	1,016,500	35.00
Exercised	318,000	31.74	42,500	27.19	307,500	27.17
Forfeited	—	—	—	—	—	—
Canceled	144,000	34.99	30,000	34.99	20,000	27.19
Outstanding at end of year	1,116,000	$32.00	1,550,000	$32.17	1,614,500	$32.09
Options exercisable at end of year	1,106,000	$31.98	1,068,500	$30.88	606,500	$27.22

The fair value of each unit option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

Assumption	2003	2002	2001
Expected term in years	7	8	8
Expected volatility	28.93%	31.05%	27.50%
Expected distributions	8.88%	8.09%	9.55%
Risk-free interest rate	3.31%	3.24%	5.05%

The Black-Scholes weighted average fair value of options granted during 2003, 2002, and 2001 was $3.55, $3.71, and $2.62 per unit option, respectively.

Options outstanding as of December 31, 2003, are summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$19.86 to $27.80	423,500	4.6	$27.13	423,500	$27.13
$27.80 to $39.72	692,500	6.9	$34.99	682,500	$34.99
$19.86 to $39.72	1,116,000	6.0	$32.00	1,106,000	$31.98

9. Earnings Per Common Unit

The following table sets forth the computation of basic and diluted earnings per common unit (in thousands, except for unit amounts):

	For the Years Ended December 31,		
	2003	2002	2001
Numerator:			
Numerator for basic earnings per common unit —			
Income from continuing operations	$65,155	$34,275	$12,174
Income from discontinued operations	—	5,085	1,086
Cumulative effect of accounting change	1,340	—	—
	$66,495	$39,360	$13,260
Denominator:			
Denominator for basic earnings per common unit — weighted-average common units	49,953	42,814	34,376
Effect of dilutive securities:			
Unit options	177	—	—
Restricted units	15	—	—
Series F convertible units	86	—	—
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	50,231	42,814	34,376
Basic earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.03	—	—
	$ 1.33	$ 0.92	$ 0.38
Diluted earnings per common unit			
Income from continuing operations	$ 1.30	$ 0.80	$ 0.35
Income from discontinued operations	—	0.12	0.03
Cumulative effect of accounting change	0.02	—	—
	$ 1.32	$ 0.92	$ 0.38

10. Related Party Transactions

The majority of our related party transactions are with affiliates of our general partner. Under an agreement that was in place before an indirect subsidiary of El Paso Corporation purchased our general partner, an affiliate of our general partner was obligated to provide individuals to perform the day to day financial, administrative, accounting and operational functions for us. As our activities increased, the fee for such services has also increased. Further, we provide services to various El Paso Corporation subsidiaries and, in turn, they provide us services. In addition, we have acquired a number of assets from subsidiaries of El Paso Corporation. We have not had any material transactions with Enterprise, other than the merger agreement transactions, since Enterprise acquired 50 percent of our general partner.

The following table provides summary data of our transactions with related parties for the years ended December 31:

	2003	2002	2001
		(In thousands)	
Revenues received from related parties:			
Natural gas pipelines and plants	$ 84,375	$159,608	$20,710
Oil and NGL Logistics	29,413	26,288	25,249
Platform services[1]	—	—	35
Natural gas storage	—	3,016	2,325
Other[1]	—	9,809	5,676
	$113,788	$198,721	$53,995
Expenses paid to related parties:			
Purchased natural gas costs	$ 33,148	$ 22,784	$34,768
Operation and maintenance	91,208	60,458	33,721
	$124,356	$ 83,242	$68,489
Reimbursements received from related parties:			
Operation and maintenance	$ 2,426	$ 2,100	$11,499

(1) In addition to revenues from continuing operations reflected above, we also received revenues from related parties in 2002 and 2001 of $6.8 million and $8.2 million for our Prince TLP and $1.0 million and $0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statements.

For the years ended December 31, 2003, 2002 and 2001, revenues received from related parties consisted of approximately 13%, 43% and 28% of our revenue from continuing operations. Also, we have undertaken efforts to reduce our transactions with El Paso Merchant Energy North America Company (Merchant Energy) and as of June 30, 2003, we replaced all our month-to-month arrangements that were previously with Merchant Energy with similar arrangements with third parties.

The following table provides summary data categorized by our related parties for the years ended December 31:

	2003	2002	2001
		(In thousands)	
Revenues received from related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 30,146	$ 92,675	$16,433
El Paso Production Company[1]	9,109	9,054	4,230
Southern Natural Gas Company	13	112	277
Tennessee Gas Pipeline Company	93	—	638
El Paso Field Services	74,427	96,880	32,382
Unconsolidated Subsidiaries			
Manta Ray Offshore[2]	—	—	35
	$113,788	$198,721	$53,995
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	$ 27,777	$ 19,226	$28,169
El Paso Production Company	—	2,251	6,412
Southern Natural Gas Company	143	245	187
Tennessee Gas Pipeline Company	—	70	—
El Paso Field Services	5,181	950	—
El Paso Natural Gas Company	47	42	—
	$ 33,148	$ 22,784	$34,768
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	$ 90,925	$ 60,000	$33,187
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	283	458	534
	$ 91,208	$ 60,458	$33,721
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings[3]	$ —	$ —	$ 9,399
Poseidon Oil Pipeline Company	2,426	2,100	2,100
	$ 2,426	$ 2,100	$11,499

(1) In addition to revenues from continuing operations from El Paso Production Company reflected above, during 2002 and 2001 we also received revenues of $7.8 million and $8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statements.

(2) We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso Corporation's merger with the Coastal Corporation.

(3) In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. In April 2001, Deepwater Holdings sold its UTOS subsidiary. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings, and as a result of this transaction, on a going forward basis, Deepwater Holdings is consolidated in our financial statements and our agreement with Deepwater Holdings terminated.

Revenues received from related parties

EPN Holding Assets. Our revenues from related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired gathering, transportation and processing contracts with affiliates of our general partner. For the years ended December 31, 2003 and 2002, we received $26.5 million and

$68.9 million from El Paso Merchant Energy North America Company, $19.9 million and $35.8 million from El Paso Field Services and $3.4 million and $4.0 million from El Paso Production Company.

GTM Texas. In connection with our acquisition of GTM Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the years ended December 31, 2003, 2002 and 2001, we received revenue of approximately $21.5 million, $26.0 million and $25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the years ended December 31, 2002 and 2001, we received revenue of $29.6 million and $6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the years ended December 31, 2002 and 2001, we received $1.8 million and $0.6 million related to this lease. As a result of the San Juan asset acquisition in November 2002, the processing agreement and the operating lease were terminated.

Storage facilities. With the April 2002 acquisition of the EPN Holding assets, we purchased contracts held by Wilson Storage with El Paso Merchant Energy North America Company. For the year ended December 31, 2002, we received approximately $2.9 million from El Paso Merchant Energy North America Company for natural gas storage fees. El Paso Merchant Energy North America Company and Tennessee Gas Pipeline Company use our Petal and Hattiesburg storage facilities from time to time. For the years ended December 31, 2002 and 2001 we received approximately $0.1 million and $1.6 million from El Paso Merchant Energy North America Company for natural gas storage fees. For the year ended December 31, 2001 we received approximately $0.7 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. Prior to April 1, 2002, we received a monthly demand charge of approximately $1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the year ended December 31, 2002 and the four months ended December 31, 2001, we received $6.8 million and $8.2 million in platform revenue related to this agreement. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our Prince TLP to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

Production fields. Through 2000 we had agreed to sell substantially all of our oil and natural gas production to El Paso Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and $0.015 per dekatherm of natural gas for marketing production. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties and our oil and natural gas sales related to El Paso Merchant Energy North America Company were approximately $9.8 million and $5.7 million for years ended December 31, 2002 and 2001.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2002 and the four months ended December 31, 2001, we recorded approximately $1.0 million and $0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

GulfTerra Alabama Intrastate. Several El Paso Corporation subsidiaries buy and transport natural gas on our GulfTerra Alabama Intrastate system. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.7 million, $6.8 million and $8.3 million from El Paso Merchant Energy North America Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $4.5 million, $4.5 million and $4.2 million from El Paso Production Company. For the years ended December 31, 2003, 2002 and 2001, we received approximately $0.1 million, $0.1 million and $0.2 million from Southern Natural Gas Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings. HIOS is a natural gas transmission system that has entered into interruptible transportation agreements at a non-discounted rate of $0.1244. For the years ended December 31, 2003 and 2002 and approximately three months ended December 31, 2001, we received $0.1 million, $1.4 million and $0.8 million from El Paso Merchant Energy. For the year ended December 31, 2003 and 2002, we received $1.2 million and $0.6 million from El Paso Production Company.

Texas NGL assets. In connection with our acquisition of the San Juan assets in November, 2002, we entered into a 10-year transportation agreement with El Paso Field Services. Pursuant to this agreement, beginning January 1, 2003, we receive a fee of $1.5 million per year for transportation on our NGL pipeline which extends from Corpus Christi to near Houston. In addition, we provide transportation, fractionation, storage and terminaling services to El Paso Field Services, as well as to various third parties, typically under agreements of one year term or less. We received approximately $7.5 million and $0.3 million in revenues from El Paso Field Services for the years ended December 31, 2003 and 2002.

Other. In addition to the revenues discussed above, we received $2.8 million and $2.6 million from El Paso Merchant North America and $25.6 million and $3.3 million from El Paso Field Services during 2003 and 2002 for additional gathering and processing services. The 2003 increase in revenues for El Paso Field Services was primarily as a result of higher natural gas prices and NGL volumes sold to El Paso Field Services from our Big Thicket assets.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 we received approximately $0.03 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso's merger with the Coastal Corporation.

Expenses paid to related parties

Cost of natural gas. Our cost of natural gas paid to related parties increased in 2003 and 2002 as a result of our San Juan assets acquisitions and our EPN Holding transaction in which we acquired contracts with affiliates of our general partner. For the year ended December 31, 2003, our San Juan assets had cost of natural gas expenses of $1.3 million from El Paso Merchant Energy North America and $0.3 million from El Paso Field Services. For the year ended December 31, 2003 and 2002, our EPN Holding assets had cost of natural gas expenses of $0.9 million and $0.3 million from El Paso Merchant Energy North America Company and $3.5 million and $0.4 million from El Paso Field Services relating to the GulfTerra Texas gathering system. GulfTerra Alabama Intrastate's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2003, 2002 and 2001, we had natural gas purchases of approximately $25.6 million, $18.9 million and $28.2 million from El Paso Merchant Energy North America Company, and $0.1 million, $0.2 million and $0.2 million from Southern Natural Gas Company and $2.3 million and $6.4 million from El Paso Production Company for the years ended December 31, 2002 and 2001. We also receive lease and throughput fees from El Paso Field Services for Hattiesburg and Anse

La Butte. For the year ended December 31, 2002 we received $0.5 million from El Paso Field Services related to these fees.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a general and administrative services agreement between subsidiaries of El Paso Corporation and us, a fee of approximately $0.8 million per month was charged to our general partner, and accordingly, to us, which is intended to approximate the amount of resources allocated by El Paso Corporation and its affiliates in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. In April 2002, in connection with our acquisition of EPN Holding assets, our general and administrative services agreement was extended to December 31, 2005, and the fee increased to approximately $1.6 million per month. In November 2002, as a result of the San Juan assets acquisition, the monthly fee under our general and administrative services agreement increased by $1.3 million, bringing our total monthly fee to $2.9 million. We believe this fee approximates the actual costs incurred. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf.

As we became operator of additional facilities or systems, acquired new operations or constructed new facilities, we entered into additional management and operating agreements with El Paso Field Services. All fees paid under these contracts approximate actual costs incurred.

The following table shows the amount El Paso Field Services charged us for each of our agreements for the year ended December 31:

	2003	2002	2001
		(In thousands)	
Basic management fee	$34,800	$18,092	$ 9,300
Operating fees[(1)]	52,924	38,422	19,821
Insurance and other costs	3,201	3,486	4,066
	$90,925	$60,000	$33,187

(1) Operating fees increased from 2002 to 2003 and from 2001 to 2002 due to the acquisition of the San Juan assets and EPN Holding assets.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. All fees received under contracts approximate actual costs incurred.

Acquisitions

We have purchased assets from related parties. See Note 2 for a discussion of these asset acquisitions.

Other Matters

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 11, Commitments and

Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made claims for approximately $5 million for costs incurred during the year ended December 31, 2003 as costs exceeded the established thresholds for the year ended December 31, 2003.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have an agreement to receive $6.1 million, of which $3.0 million has been collected, from ANR Pipeline Company for our Phoenix project. As of December 31, 2003, we have received $10.5 million from ANR Pipeline and $7.0 million from El Paso Field Services for the Marco Polo natural gas pipeline. In October 2003, we collected $2 million from Tennessee Gas Pipeline for our Medusa project. These amounts are reflected as a reduction in project costs. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines. El Paso Field Services' contribution is in anticipation of additional natural gas volumes that will flow through to its onshore natural gas processing facilities.

In August 2003, Arizona Gas Storage L.L.C., along with its 50 percent partner APACS Holdings L.L.C., sold their interest in Copper Eagle Gas Storage L.L.C. to El Paso Natural Gas Company (EPNG), a subsidiary of El Paso Corporation. Copper Eagle Gas Storage is developing a natural gas storage project located outside of Phoenix, Arizona. Arizona Gas Storage is an indirect 60 percent owned subsidiary of us and 40 percent owned by IntraGas US, a Gaz de France North American subsidiary. APACS Holdings L.L.C. is a wholly owned subsidiary of Pinnacle West Energy, a subsidiary of Pinnacle West Capital Corporation. We have the right to receive $6.2 million of the sale proceeds, including a note receivable for $4.9 million to be paid quarterly over the next twelve months, from EPNG and we recorded a gain of $882 thousand related to the sale of Copper Eagle. In the event of EPNG default, the Copper Eagle Gas Storage project will revert back to the original owners without compensation to EPNG.

In September 2003, we entered into a nonbinding letter of intent with Southern Natural Gas Company, a subsidiary of El Paso Corporation, regarding the proposed development and sale of a natural gas storage cavern and the proposed sale of an undivided interest in a pipeline and other facilities related to that natural gas storage cavern. The new storage cavern would be located at our storage complex near Hattiesburg, Mississippi. If Southern Natural Gas determines that there is sufficient market interest, it would purchase the land and mineral rights related to the proposed storage cavern and would pay our costs to construct the storage cavern and related facilities. Upon completion of the storage cavern, Southern Natural Gas would acquire an undivided interest in our Petal pipeline connected to the storage cavern. We would also enter into an arrangement with Southern Natural Gas under which we would operate the storage cavern and pipeline on its behalf.

Before we consummate this transaction, and enter into definitive transaction documents, the transaction must be recommended by the audit and conflicts committee of our general partner's board of directors, which committee consists solely of directors meeting the independent director requirements established by the NYSE and the Sarbanes-Oxley Act, and then approved by our general partner's full board of directors.

In October 2003, we exchanged with El Paso Corporation its obligation to repurchase the Chaco plant from us in 19 years for additional assets (refer to Note 2). Also in October 2003, we redeemed all of our outstanding Series B preference units (refer to Note 8).

The counterparty for one of our San Juan hedging activities is J. Aron and Company, an affiliate of Goldman Sachs. Goldman Sachs was also a co-manager of our 4,800,000 public common unit offering in October 2003, and is one of the lenders under our revolving credit facility and owned 9.9 percent of our general partner during part of the fourth quarter of 2003.

Our accounts receivable due from related parties consisted of the following as of:

	December 31, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 4,113	$30,512
El Paso Production Company	5,991	4,346
Tennessee Gas Pipeline Company	1,350	930
El Paso Field Services[(1)]	16,571	36,071
El Paso Natural Gas Company	4,255	1,033
ANR Pipeline Company	1,600	671
Other	830	627
	34,710	74,190
Unconsolidated Subsidiaries		
Deepwater Gateway	3,939	9,636
Cameron Highway	9,302	—
Other	14	—
	13,255	9,636
Total	$47,965	$83,826

(1) The December 2002 receivable balance includes approximately $15 million of natural gas imbalances relating to our EPN Holding acquisition.

Our accounts payable due to related parties consisted of the following as of:

	December 31, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 7,523	$ 8,871
El Paso Production Company	4,069	14,518
Tennessee Gas Pipeline Company	1,278	1,319
El Paso Field Services[(1)]	13,869	55,648
El Paso Natural Gas Company	942	1,475
El Paso Corporation	6,249	4,181
Southern Natural Gas	1,871	—
Other	667	132
	36,468	86,144
Unconsolidated Subsidiaries		
Deepwater Gateway	2,268	—
Other	134	—
	2,402	—
Total	$38,870	$86,144

(1) The December 2002 payable balance includes approximately $19 million of working capital adjustments relating to our EPN Holding acquisition due to El Paso Field Services; and approximately $22 million of natural gas imbalances relating to our EPN Holding acquisition.

In connection with the sale of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and ending with a $2 million payment in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

	December 31, 2003	December 31, 2002
	(In thousands)	
Accounts receivable, net	$1,960	$ 8,403
Other noncurrent assets	—	1,960
	$1,960	$10,363

11. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, we, along with numerous other energy companies, were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to 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). Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). We, along with numerous other energy companies, are named 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 certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that they contend these owners 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, attorney's 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 on April 10, 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 petition has been filed as to heating content claims. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

In connection with our April 2002 acquisition of the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P., City of Edinburg, Houston Pipe Line Company LP, and City of Corpus Christi discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of

Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services filed an appeal with the Eighth Court of Appeals in El Paso, Texas. On August 15, 2003 the Court of Appeals reversed the lower's courts calculation of past judgment interest but otherwise affirmed the judgment. A motion for a rehearing was denied. A petition for review by the Texas Supreme Court has been filed.

Also, GulfTerra Texas Pipeline L.P., (GulfTerra Texas, formerly known as EPGT Texas Pipeline L.P.) now owned by GulfTerra Holding, was involved in litigation with the City of Edinburg concerning the City's claim that GulfTerra Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by GulfTerra Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and GulfTerra Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both GulfTerra Texas and Southern Union jointly and severally liable to the City for approximately $4.7 million. The judgment relied on the single business enterprise doctrine to impose contractual obligations on GulfTerra Texas and Southern Union entities that were not parties to the contract with the City. GulfTerra Texas appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against GulfTerra Texas. The City sought a remand to the trial court of its claim of tortious interference against GulfTerra Texas. Briefs were filed and oral arguments were held in November 2002. In October 2003, the Texas Supreme Court issued an opinion in favor of GulfTerra Texas and Southern Union on all issues. The City has requested rehearing.

In December 2000, a 30-inch natural gas pipeline jointly owned by GulfTerra Intrastate, L.P. (GulfTerra Intrastate) now owned by GulfTerra Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. GulfTerra Intrastate is the operator of the pipeline. Two lawsuits were filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits sought recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company was added as an additional defendant. In accordance with the terms of the operating agreement, GulfTerra Intrastate agreed to assume the defense of and to indemnify Houston Pipe Line Company. As of December 31, 2003, all claims have now been settled and these settlements had no impact on our financial statements.

The City of Corpus Christi, Texas (the "City") alleged that GulfTerra Texas and various Coastal entities owed it monies for past obligations under City ordinances that propose to tax GulfTerra Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. Some but not all of the GulfTerra Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demanded that GulfTerra Texas agree to a going-forward consent agreement in order for the GulfTerra Texas pipe and Coastal pipe to have the right to remain in the City rights-of-way. In December 2003, GulfTerra Texas and the City entered into a license agreement releasing GulfTerra Texas from any past obligations and providing certain rights for the use of the City rights-of-way and City owned property. This agreement was retroactive to October 1, 2002.

In August 2002, we acquired the Big Thicket assets, which consist of the Vidor plant, the Silsbee compressor station and the Big Thicket gathering system located in east Texas, for approximately $11 million from BP America Production Company (BP). Pursuant to the purchase agreement, we have identified environmental conditions that we are working with BP and appropriate regulatory agencies to address. BP has agreed to indemnify us for exposure resulting from activities related to the ownership or operation of these facilities prior to our purchase (i) for a period of three years for non-environmental claims and (ii) until one year following the completion of any environmental remediation for environmental claims. Following expiration of these indemnity periods, we are obligated to indemnify BP for environmental or non-environmental claims. We, along with BP and various other defendants, have been named in the following two lawsuits for claims based on activities occurring prior to our purchase of these facilities.

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et. al. In June 2003, the plaintiffs sued us in state district court in Hardin County, Texas. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between GulfTerra and BP, GulfTerra requested that BP indemnify GulfTerra for any exposure. BP has agreed to indemnify us in this matter.

Melissa Duvail, et. al., v. GulfTerra GC, L.P., et. al. In June 2003, seventy-four residents of Hardin County, Texas, sued us and others in state district court in Hardin County, Texas. The plaintiffs allege that they have been exposed to hazardous chemicals, including arsenic and benzene, through their water supply, and that the defendants are responsible for that exposure. As with the Beverly case, our connection with the occurrences that are the basis of this suit appears to be our August 2002 purchase of certain assets from BP, including a facility known as the Silsbee compressor station, which is located in Hardin County, Texas. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, BP has agreed to indemnify us for this matter.

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.

For each of our outstanding legal matters, we evaluate the merits of the case, 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, we will establish the necessary accruals. As of December 31, 2003, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and 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, 2003, we had a reserve of approximately $21 million, included in other noncurrent liabilities, for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $3 million in the aggregate for the years 2004 through 2008, primarily to comply with clean air regulations.

Shoup Air Permit Violation. 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 NoE included a draft Agreed Order assessing a penalty of $365,750 for the cited violations. The alleged violations pertained to emission limit exceedences, testing, reporting, and recordkeeping issues in 2001. While the NoE was addressed to El Paso Field Services, L.P., the substance of the NoE also concerns equipment owned at the Shoup plant by Gulfterra GC, L.P. El Paso Field Services, L.P. has responded to the NoE and is preparing to meet with the TCEQ to discuss the alleged violations and the proposed penalty.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or 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 reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate Final Rule. In November 2003, the FERC issued a Final Rule extending its standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our HIOS natural gas pipeline and Petal natural gas storage facility, including the 60-mile Petal natural gas pipeline, are interstate facilities as defined by the Natural Gas Act, the regulations dictate how HIOS and Petal conduct business and interact with all energy affiliates of El Paso Corporation and us.

The standards of conduct require us, absent a waiver, to functionally separate our HIOS and Petal interstate facilities from our other entities. We must dedicate employees to manage and operate our interstate facilities independently from our other Energy Affiliates. This employee group must function independently and is prohibited from communicating non-public transportation information or customer information to its Energy Affiliates. Separate office facilities and systems are necessary because of the requirement to restrict affiliate access to interstate transportation information. The Final Rule also limits the sharing of employees and offices with Energy Affiliates. The Final Rule was effective on February 9, 2004, subject to possible rehearing. On that date, each transmission provider filed with FERC and posted on the internet website a plan and scheduling for implementing this Final Rule. By June 1, 2004, written procedures implementing this Final Rule will be posted on the internet website. Requests for rehearing have been filed and are pending. At this time, we cannot predict the outcome of these requests, but at a minimum, adoption of the regulations in the form outlined in the Final Rule will place additional administrative and operational burdens on us.

Pipeline Safety Final Rule. In December 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas," or HCA. The final rule requires operators to (1) perform ongoing assessments of pipeline integrity; (2) identify and characterize applicable threats to pipeline segments that could impact an HCA; (3) improve data collection, integration and analysis; (4) repair and remediate the pipeline as necessary; and (5) implement preventive and mitigative actions. The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. The Final Rule is effective as of January 14, 2004. At this time, we cannot predict the outcome of this final rule.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. As of July 1, 2003, HIOS implemented the requested rates, subject to a refund, and has established a reserve for its estimate of its refund obligation. We will continue to review our expected refund obligation as the rate case moves through the hearing process and may increase or decrease the amounts reserved for refund obligation as our expectation changes. The FERC has conducted a hearing on this matter and an initial decision is expected to be issued in April 2004.

During the latter half of 2002, we experienced a significant unfavorable variance between the fuel usage on HIOS and the fuel collected from our customers for our use. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. As of December 31, 2003, we had recorded fuel differences of approximately $8.2 million, which is included in other non-current assets. We are currently in discussions with the FERC as well as our customers regarding the potential collection of some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers will negatively impact our earnings.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. On February 25, 2004, the FERC issued an order denying GulfTerra Texas' request for rehearing and ordered GulfTerra Texas to file, within 45 days from the issuance of the order, a calculation of refunds and a refund plan. Additionally, the FERC ordered GulfTerra Texas to file a new rate case or justification of existing rates within three years from the date of the order.

In July 2002, Falcon Gas Storage, a competitor, also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. The FERC denied Falcon's late intervention on February 25, 2004. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider.

Falcon filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied. The Railroad Commission has set their case for hearing beginning on April 13, 2004. The City Board of Public Service of San Antonio filed an intervention in opposition to Falcon's complaint.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint venture arrangements (including our Cameron Highway, Deepwater Gateway and Poseidon joint ventures) we form to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources including proceeds from credit arrangements.

Operating Lease

We have long-term operating lease commitments associated with the Wilson natural gas storage facility we acquired in April 2002 in connection with the EPN Holding acquisition. The term of the natural gas storage facility and base gas leases runs through January 2008, and subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal. We also have long-term operating lease commitments associated with two NGL storage facilities in Texas we acquired in November 2002 in connection with our San Juan asset acquisition. The leases covering these facilities expire in 2006 and 2012.

The future minimum lease payments under these operating lease commitments as of December 31, 2003 are as follows (in millions):

2004	$ 7
2005	7
2006	7
2007	6
2008	3
Thereafter	2
Total minimum lease payments	$32

Rental expense under operating leases was approximately $7.2 million and $3.9 million for the years ended December 31, 2003 and 2002. We did not have any operating leases prior to our acquisition of the EPN Holding assets in April 2002.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question. As a result of these general circumstances, we have established an internal group to monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

12. Accounting for Hedging Activities

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids and purchases or sales of gas associated with our processing plants and our gathering activities, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* We did not have any derivative contracts in place at December 31, 2000, and therefore, there was no transition adjustment recorded in our financial statements. During 2003, 2002 and 2001, we entered into cash flow hedges.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative through current earnings since it did not qualify for hedge accounting under SFAS No. 133. Through the acquisition date in 2002, we recognized a $0.4 million gain in the margin of our natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February and August 2003, we entered into additional derivative financial instruments to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivatives are financial swaps on 30,000 MMBtu per day whereby we receive an average fixed price of $4.23 per MMBtu and pay a floating price based on the San Juan index. As of December 31, 2003 and 2002, the fair value of these cash flow hedges was a liability of $5.8 million and $4.8 million, as the market price at those dates was higher than the hedge price. For the year ended December 31, 2003, we reclassified approximately $9.8 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income as a decrease in revenue. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. In connection with our San Juan asset purchase, we also acquired the outstanding risk management positions at the Chaco plant. The value of these NGL and natural gas positions was a $0.5 million liability at the acquisition date and this amount was included in the working capital adjustments to the purchase price. These positions expired in December 2002.

In connection with our GulfTerra Alabama Intrastate operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices. As of December 31, 2003, the fair value of these cash flow hedges was an asset of approximately $77 thousand. For the twelve months ended December 31, 2003, we reclassified approximately $218 thousand of unrealized accumulated gain related to these derivatives from accumulated other comprehensive income to earnings. As of December 31, 2002, the fair value of these cash flow hedges was an asset of $86 thousand. During the year ended December 31, 2002, we reclassified a loss of $1.4 million from other comprehensive income to earnings. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

Beginning in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002, and we recorded a loss of $163 thousand during 2002 for these cash flow hedges. We did not have any ineffectiveness in our hedging relationship since all sale prices were based on the same index as the hedge transaction.

During 2003, we entered into additional derivative financial instruments to hedge a portion of our business' exposure to changes in NGL prices during 2003 and 2004. We entered into financial swaps for 3,500 barrels per day for February through June 2003, 3,200 barrels per day for July 2003, 4,900 barrels per day for August 2003, and 6,000 barrels per day for August 2003 through September 2004. The average fixed price received was $0.49 per gallon for 2003 and will be $0.47 per gallon for 2004 while we pay a monthly average floating price based on the OPIS average price for each month. As of December 31, 2003, the fair value of these cash flow hedges was a liability of $3.3 million. For the twelve months ended December 31, 2003, we reclassified approximately $0.4 million of unrealized accumulated loss related to these derivatives from accumulated other comprehensive income to earnings.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. This interest rate swap expired on January 9, 2004. We have recognized as a reduction in income our 36 percent share of Poseidon's realized loss on the interest rate swap of $1.7 million for the twelve months ended December 31, 2003, or $0.6 million, through our earnings from unconsolidated affiliates. As of December 31, 2002, the fair value of its interest rate swap was a liability of $1.4 million, as the market interest rate was lower than the hedge rate, resulting in accumulated other comprehensive loss of $1.4 million. We included our 36 percent share of this liability of $0.5 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income. Additionally, we recognized in income our 36 percent share of Poseidon's realized loss of $1.2 million for the twelve months ended December 31, 2002, or $0.4 million, through our earnings from unconsolidated affiliates.

We estimate the entire $9.0 million of unrealized losses included in accumulated other comprehensive income at December 31, 2003, will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next 12 months. When our derivative financial instruments are settled, the related amount in accumulated other comprehensive income is recorded in the income statement in operating revenues, cost of natural gas and other products, or interest and debt expense, depending on the item being hedged. The effect of reclassifying these amounts to the income statement line items is recording our earnings for the period at the ''hedged price'' under the derivative financial instruments.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on $250 million out of $480 million of our 8½% senior subordinated notes due 2011. With this swap agreement, we pay the counterparty a LIBOR based interest rate plus a spread of 4.20% (which rate was 1.55% at December 31, 2003) and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge under SFAS No. 133. As of December 31, 2003, the fair value of the interest rate swap was a liability included in non-current liabilities of approximately $7.4 million and the fair value of the hedged debt decreased by the same amount.

The counterparties for our San Juan hedging activities are J. Aron and Company, an affiliate of Goldman Sachs, and UBS Warburg. We do not require collateral and do not anticipate non-performance by these counterparties. Through June 2003, the counterparty for our GulfTerra Alabama Intrastate operations was El Paso Merchant Energy. Beginning in August 2003, the counterparty is UBS Warburg, and we do not require collateral or anticipate non-performance by this counterparty. The counterparty for our NGL hedging activities for the Indian Basin and Chaco plants is J. Aron and Company, an affiliate of Goldman Sachs. We do not require collateral and do not anticipate non-performance by this counterparty. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by this counterparty. Wachovia Bank is our counterparty on our interest rate swap on the 8½% notes, and we do not require collateral or anticipate non-performance by this counterparty.

13. Supplemental Disclosures to the Statements of Cash Flows

Cash paid for interest, net of amounts capitalized were as follows:

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Interest	$135,131	$73,598	$41,020

Noncash investing and financing activities excluded from the consolidated statements of cash flows were as follows:

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Investment in Cameron Highway Oil Pipeline Company Joint Venture	$50,836	$ —	$ —
Exchange with El Paso Corporation	23,275	—	—
Adoption of SFAS No. 143	5,726	—	—
Note receivable due to sale of Copper Eagle	3,656		
Increase in property, plant and equipment, offset by accounts payable and other noncurrent liabilities due to purchase price adjustments	377		
Acquisition of San Juan assets			
Issuance of Series C units	—	350,000	—
Investment in processing agreement classified to property, plant and equipment	—	114,412	—
Acquisition of EPN Holding assets			
Issuance of common units	—	6,000	—
Acquisition of additional 50 percent interest in Deepwater Holdings			
Working capital acquired	—	—	7,494

14. Major Customers

The percentage of our revenue from major customers was as follows:

	Year Ended December 31,		
	2003	2002	2001
Chevron	14%	—	—
BHP Petroleum	14%	—	—
Burlington Resources	13%	—	—
El Paso Merchant Energy North America Company	—	21%	—
El Paso Field Services	—	18%	16%
Alabama Gas Corporation	—	—	14%

The 2003 major customers are a result of our San Juan asset acquisition in November 2002. Also, during 2003 we decreased our activities with affiliates of El Paso Corporation, including replacing all our month-to-month arrangements that were previously with El Paso Merchant Energy with similar arrangements with third parties. The 2002 percentage increase in revenue from El Paso Merchant Energy North America Company and El Paso Field Services is primarily due to our EPN Holding acquisition completed in 2002.

15. Business Segment Information:

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies and we have segregated our business activities into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

The accounting policies of the individual segments are the same as those described in Note 1. We record intersegment revenues at rates that approximate market.

We use performance cash flows (which we formerly referred to as EBITDA) to evaluate the performance of our segments, determine how resources will be allocated and develop strategic plans. We define performance cash flows as earnings before interest, income taxes, depreciation and amortization and other adjustments. Historically our lenders and equity investors have viewed our performance cash flows measure as an indication of our ability to generate sufficient cash to meet debt obligations or to pay distributions, we believe that there has been a shift in investors' evaluation regarding investments in MLPs and they now put as much focus on the performance of an MLP investment as they do its ability to pay distributions. For that reason, we disclose performance cash flows as a measure of our segment's performance. We believe performance cash flows is also useful to our investors because it allows them to evaluate the effectiveness of our business segments from an operational perspective, exclusive of the costs to finance those activities, income taxes and depreciation and amortization, none of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures.

Our operating results and financial position reflect the acquisitions of the San Juan assets in November 2002, the EPN Holding assets in April 2002, the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001 and GTM Texas in February 2001. The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included prospectively from the purchase date. The following are results as of and for the periods ended December 31:

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Non-Segment Activity[1]	Total
			(In thousands)			
For the Year Ended December 31, 2003						
Revenue from external customers	$ 734,670	$ 53,850	$ 44,297	$ 20,861	$ 17,811	$ 871,489
Intersegment revenue	127	—	278	2,603	(3,008)	—
Depreciation, depletion and amortization	68,747	8,603	11,720	5,334	4,442	98,846
Earnings from unconsolidated investments	2,377	8,098	898	—	—	11,373
Performance cash flows	311,164	59,053	29,554	20,181	N/A	N/A
Assets	2,289,546	464,246	315,853	162,275	89,660	3,321,580
For the Year Ended December 31, 2002						
Revenue from external customers[2]	$ 357,581	$ 37,645	$ 28,602	$ 16,672	$ 16,890	$ 457,390
Intersegment revenue	227	—	—	9,283	(9,510)	—
Depreciation, depletion and amortization	44,479	6,481	8,503	4,205	8,458	72,126
Earnings from unconsolidated investments	194	13,445	—	—	—	13,639
Performance cash flows	167,185	43,347	16,629	29,224	N/A	N/A
Assets	2,279,955	265,900	320,662	140,758	123,621	3,130,896
For the Year Ended December 31, 2001						
Revenue from external customers	$ 100,683	$ 32,327	$ 19,373	$ 15,385	$ 25,638	$ 193,406
Intersegment revenue	381	—	—	12,620	(13,001)	—
Depreciation, depletion and amortization	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge	3,921	—	—	—	—	3,921
Earnings (loss) from unconsolidated investments	(9,761)	18,210	—	—	—	8,449
Performance cash flows	52,200	47,560	13,209	30,783	N/A	N/A
Assets	563,698	195,839	226,991	115,364	69,968	1,171,860

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Non-Segment Activity" column, to remove intersegment transactions.

(2) The revenue amount for our Oil and NGL Logistics segment has been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of sales and other products. See Note 1, Summary of Significant Accounting Policies, for a further discussion.

A reconciliation of our segment performance cash flows to our net income is as follows:

	Years Ended December 31, 2003	2002	2001
Natural gas pipelines & plants	$311,164	$167,185	$ 52,200
Oil & NGL logistics	59,053	43,347	47,560
Natural gas storage	29,554	16,629	13,209
Platform services	20,181	29,224	30,783
Segment performance cash flows	419,952	256,385	143,752
Plus: Other, nonsegment results	15,107	10,427	17,688
Earnings from unconsolidated affiliates	11,373	13,639	8,449
Income from discontinued operations	—	5,136	1,097
Cumulative effect of accounting change	1,690	—	—
Noncash hedge gain	—	411	—
Noncash earnings related to future payments from El Paso Corporation	—	—	25,404
Less: Interest and debt expense	127,830	81,060	41,542
Loss due to early redemptions of debt	36,846	2,434	—
Depreciation, depletion and amortization	98,846	72,126	34,778
Asset impairment charge	—	—	3,921
Cash distributions from unconsolidated affiliates	12,140	17,804	35,062
Minority interest	917	(60)	100
Net cash payment received from El Paso Corporation	8,404	7,745	7,426
Discontinued operations of Prince facilities	—	7,201	6,561
Loss on sale of Gulf of Mexico assets	—	—	11,851
Net income	$163,139	$ 97,688	$ 55,149

16. Guarantor Financial Information

In May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries for $8 million. As a result of this acquisition, all our subsidiaries, but not our equity investees, are wholly owned by us. As of December 31, 2003, our credit facility is guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and is collateralized by substantially all of our assets. In addition, all of our senior notes and senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries, excluding our unrestricted subsidiaries. As of December 31, 2002, our revolving credit facility, GulfTerra Holding term credit facility, senior secured term loan and senior secured acquisition term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.), and are collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, as of December 31, 2002, all of our senior subordinated notes are jointly, severally, fully and unconditionally guaranteed by us and all our subsidiaries excluding our unrestricted subsidiaries. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

Non-guarantor subsidiaries for the year ended December 31, 2003, consisted of our unrestricted subsidiaries (Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C.). Non-guarantor subsidiaries for the year ended December 31, 2002, consisted of Argo and Argo I for the quarter ended March 31, 2002, our GulfTerra Holding (then known as EPN Holding) subsidiaries, which owned the EPN Holding assets and equity interests in GulfTerra Holding (then known as EPN Holding), for the quarters ended June 30, 2002 and September 30, 2002, and our unrestricted subsidiaries for the quarter ended December 31, 2002. Non-guarantor subsidiaries for all other periods consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
For the Year Ended December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ —	$171,738	$ —	$171,738
NGL sales	—	—	121,167	—	121,167
Gathering and transportation	—	815	387,962	—	388,777
Processing	—	—	52,988	—	52,988
	—	815	733,855	—	734,670
Oil and NGL logistics					
Oil sales	—	—	2,231	—	2,231
Oil transportation	—	—	26,769	—	26,769
Fractionation	—	—	22,034	—	22,034
NGL Storage	—	—	2,816	—	2,816
	—	—	53,850	—	53,850
Platform services	—	—	20,861	—	20,861
Natural gas storage	—	—	44,297	—	44,297
Other — oil and natural gas production	—	—	17,811	—	17,811
	—	815	870,674	—	871,489
Operating expenses					
Cost of natural gas and other products	—	—	287,157	—	287,157
Operation and maintenance	5,908	279	183,515	—	189,702
Depreciation, depletion and amortization	148	42	98,656	—	98,846
(Gain) loss on sale of long-lived assets	(19,000)	—	321	—	(18,679)
	(12,944)	321	569,649	—	557,026
Operating income	12,944	494	301,025	—	314,463
Earnings from consolidated affiliates	236,753	—	—	(236,753)	—
Earnings from unconsolidated affiliates	—	898	10,475	—	11,373
Minority interest expense	—	(917)	—	—	(917)
Other income	784	—	422	—	1,206
Interest and debt expense (income)	51,721	(3)	76,112	—	127,830
Loss due to early redemptions of debt	35,621	—	1,225	—	36,846
Income from continuing operations	163,139	478	234,585	(236,753)	161,449
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$163,139	$ 478	$236,275	$(236,753)	$163,139

CONDENSED CONSOLIDATING STATEMENT OF INCOME
Year Ended December 31, 2002

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ 30,778	$ 54,223	$ —	$ 85,001
NGL sales	—	15,050	17,928	—	32,978
Gathering and transportation	—	71,560	122,776	—	194,336
Processing	—	5,316	39,950	—	45,266
	—	122,704	234,877	—	357,581
Oil and NGL logistics					
Oil sales	—	—	108	—	108
Oil transportation	—	—	8,364	—	8,364
Fractionation	—	—	26,356	—	26,356
NGL storage	—	—	2,817	—	2,817
	—	—	37,645	—	37,645
Platform services	—	—	16,672	—	16,672
Natural gas storage	—	2,699	25,903	—	28,602
Other — oil and natural gas production	—	—	16,890	—	16,890
	—	125,403	331,987	—	457,390
Operating expenses					
Cost of natural gas and other products	—	39,280	69,539	—	108,819
Operation and maintenance	6,056	27,701	81,405	—	115,162
Depreciation, depletion and amortization	274	10,729	61,123	—	72,126
Loss on sale of long-lived assets	—	—	473	—	473
	6,330	77,710	212,540	—	296,580
Operating income	(6,330)	47,693	119,447	—	160,810
Earnings from consolidated affiliates	64,851	—	29,714	(94,565)	—
Earnings from unconsolidated affiliates	—	—	13,639	—	13,639
Minority interest income	—	60	—	—	60
Other income	1,471	5	61	—	1,537
Interest and debt expense (income)	(37,696)	22,048	96,708	—	81,060
Loss due to early redemptions of debt	—	—	2,434	—	2,434
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Income from discontinued operations	—	4,004	1,132	—	5,136
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688

(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENT OF INCOME
Year Ended December 31, 2001

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues					
Natural gas pipelines and plants					
Natural gas sales	$ —	$ —	$ 59,701	$ —	$ 59,701
Gathering and transportation	—	—	33,849	—	33,849
Processing	—	—	7,133	—	7,133
	—	—	100,683	—	100,683
Oil and NGL logistics					
Oil transportation	—	—	7,082	—	7,082
Fractionation	—	—	25,245	—	25,245
	—	—	32,327	—	32,327
Platform services	—	—	15,385	—	15,385
Natural gas storage	—	—	19,373	—	19,373
Other — oil and natural gas production	—	—	25,638	—	25,638
	—	—	193,406	—	193,406
Operating expenses					
Cost of natural gas and other products	—	—	51,542	—	51,542
Operation and maintenance	(200)	—	33,479	—	33,279
Depreciation, depletion and amortization	323	—	34,455	—	34,778
Asset impairment charge	—	—	3,921	—	3,921
Loss on sale of long-lived assets	10,941	—	426	—	11,367
	11,064	—	123,823	—	134,887
Operating income (loss)	(11,064)	—	69,583	—	58,519
Earnings from consolidated affiliates	22,393	—	1,308	(23,701)	—
Earnings from unconsolidated affiliates	—	—	8,449	—	8,449
Minority interest expense	—	—	(100)	—	(100)
Other income	28,492	—	234	—	28,726
Interest and debt expense (income)	(15,328)	—	56,870	—	41,542
Income from continuing operations	55,149	—	22,604	(23,701)	54,052
Income (loss) from discontinued operations	—	1,308	(211)	—	1,097
Net income	$ 55,149	$1,308	$ 22,393	$(23,701)	$ 55,149

(1) Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 30,425	$ —	$ —	$ —	$ 30,425
Accounts receivable, net					
Trade	—	61	43,142	—	43,203
Unbilled trade	—	52	63,015	—	63,067
Affiliates	746,126	3,541	41,606	(743,308)	47,965
Affiliated note receivable	—	3,713	55	—	3,768
Other current assets	3,573	—	17,022	—	20,595
Total current assets	780,124	7,367	164,840	(743,308)	209,023
Property, plant and equipment, net	8,039	431	2,886,022	—	2,894,492
Intangible assets	—	—	3,401	—	3,401
Investments in unconsolidated affiliates	—	—	175,747	—	175,747
Investments in consolidated affiliates	2,108,104	—	622	(2,108,726)	—
Other noncurrent assets	199,761	—	9,155	(169,999)	38,917
Total assets	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580
Current liabilities					
Accounts payable					
Trade	$ —	$ 22	$ 113,798	$ —	$ 113,820
Affiliates	10,691	3,499	767,988	(743,308)	38,870
Accrued gas purchase costs	—	—	15,443	—	15,443
Accrued interest	10,930	—	269	—	11,199
Current maturities of senior secured term loan	3,000	—	—	—	3,000
Other current liabilities	2,601	1	24,433	—	27,035
Total current liabilities	27,222	3,522	921,931	(743,308)	209,367
Revolving credit facility	382,000	—	—	—	382,000
Senior secured term loans, less current maturities	297,000	—	—	—	297,000
Long-term debt	1,129,807	—	—	—	1,129,807
Other noncurrent liabilities	7,413	—	211,629	(169,999)	49,043
Minority interest	—	1,777	—	—	1,777
Partners' capital	1,252,586	2,499	2,106,227	(2,108,726)	1,252,586
Total liabilities and partners' capital	$3,096,028	$7,798	$3,239,787	$(3,022,033)	$3,321,580

CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2002

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 20,777	$ —	$ 15,322	$ —	$ 36,099
Accounts receivable, net					
Trade	—	36	90,343	—	90,379
Unbilled trade	—	38	49,102	—	49,140
Affiliates	709,230	3,055	67,513	(695,972)	83,826
Other current assets	1,118	—	2,333	—	3,451
Total current assets	731,125	3,129	224,613	(695,972)	262,895
Property, plant and equipment, net	6,716	454	2,717,768	—	2,724,938
Intangible assets	—	—	3,970	—	3,970
Investments in unconsolidated affiliates	—	5,197	90,754	—	95,951
Investments in consolidated affiliates	1,787,767	—	693	(1,788,460)	—
Other noncurrent assets	205,262	—	7,879	(169,999)	43,142
Total assets	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade	$ —	$ 302	$ 119,838	$ —	$ 120,140
Affiliates	18,867	2,982	760,267	(695,972)	86,144
Accrued interest	14,221	—	807	—	15,028
Accrued gas purchase costs	—	—	6,584	—	6,584
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	1,645	5	19,545	—	21,195
Total current liabilities	39,733	3,289	907,041	(695,972)	254,091
Revolving credit facility	491,000	—	—	—	491,000
Senior secured term loans, less current maturities	392,500	—	160,000	—	552,500
Long-term debt	857,786	—	—	—	857,786
Other noncurrent liabilities	(1)	—	193,725	(169,999)	23,725
Minority interest	—	1,942	—	—	1,942
Partners' capital	949,852	3,549	1,784,911	(1,788,460)	949,852
Total liabilities and partners' capital	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896

(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
Year Ended December 31, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 163,139	$ 478	$ 236,275	$(236,753)	$ 163,139
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income from continuing operations	163,139	478	234,585	(236,753)	161,449
Adjustments to reconcile net income to net cash provided by (used in) operating activities					
Depreciation, depletion and amortization	148	42	98,656	—	98,846
Distributed earning of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	(898)	(10,475)	—	(11,373)
Distributions from unconsolidated affiliates	—	—	12,140	—	12,140
(Gain) loss on sale of long-lived assets	(19,000)	—	321	—	(18,679)
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	11,320	—	1,224	—	12,544
Amortization of debt issuance cost	7,118	—	380	—	7,498
Other noncash items	1,224	1,206	1,015	—	3,445
Working capital changes, net of acquisitions and non-cash transactions	3,193	(533)	(362)	—	2,298
Net cash provided by operating activities	167,142	295	337,484	(236,753)	268,168
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(145)	—	(145)
Additions to property, plant and equipment	(2,166)	(19)	(329,834)	—	(332,019)
Proceeds from the sale and retirement of assets	69,836	—	8,075	—	77,911
Proceeds from sale of investments in unconsolidated affiliates	—	1,355	—	—	1,355
Additions to investments in unconsolidated affiliates	—	(211)	(35,325)	—	(35,536)
Repayments on note receivable	—	1,238	—	—	1,238
Cash paid for acquisitions, net of cash acquired	—	(20)	—	—	(20)
Net cash provided by (used in) investing activities	67,670	2,343	(357,229)	—	(287,216)
Cash flows from financing activities:					
Net proceeds from revolving credit facility	533,564	—	—	—	533,564
Repayments of revolving credit facility	(647,000)	—	—	—	(647,000)
Net proceeds from senior secured acquisition term loan	(23)	—	—	—	(23)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Repayment of GulfTerra Holding term loan	—	—	(160,000)	—	(160,000)
Net proceeds from senior secured term loan	299,512	—	—	—	299,512
Repayment of senior secured term loan	(160,000)	—	—	—	(160,000)
Net proceeds from issuance of long-term debt	537,428	—	—	—	537,426
Repayments of long-term debt	(269,401)	—	—	—	(269,401)
Net proceeds from issuance of common units	509,008	—	—	—	509,010
Redemption of Series B preference units	(155,673)	—	—	—	(155,673)
Advances with affiliates	(399,780)	(1,396)	164,423	236,753	—
Distributions to partners	(238,397)	—	—	—	(238,397)
Distributions to minority interests	—	(1,242)	—	—	(1,242)
Contribution from general partner	3,098	—	—	—	3,098
Net cash provided by (used in) financing activities	(225,164)	(2,638)	4,423	236,753	13,374
Increase (decrease) in cash and cash equivalents	$ 9,648	$ —	$ (15,322)	$ —	(5,674)
Cash and cash equivalents at beginning of year					36,099
Cash and cash equivalents at end of year					$ 30,425

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOW
Year Ended December 31, 2002

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 97,688	$ 29,714	$ 64,851	$(94,565)	$ 97,688
Less income from discontinued operations	—	4,004	1,132	—	5,136
Income from continuing operations	97,688	25,710	63,719	(94,565)	92,552
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	274	10,730	61,122	—	72,126
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(13,639)	—	(13,639)
Distributions from unconsolidated affiliates	—	—	17,804	—	17,804
Loss on sale of long-lived assets	—	—	473	—	473
Loss due to write-off of unamortized debt issuance costs, premiums and discounts	—	—	2,434	—	2,434
Amortization of debt issuance cost	3,449	621	373	—	4,443
Other noncash items	1,053	1,942	1,434	—	4,429
Working capital changes, net of acquisitions and non-cash transactions	16,812	(21,676)	(5,002)	—	(9,866)
Net cash provided by continuing operations	119,276	17,327	128,718	(94,565)	170,756
Net cash provided by discontinued operations	—	4,631	613	—	5,244
Net cash provided by operating activities	119,276	21,958	129,331	(94,565)	176,000
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(1,682)	—	(1,682)
Additions to property, plant and equipment	(4,619)	(9,099)	(188,823)	—	(202,541)
Proceeds from the sale and retirement of assets	—	—	5,460	—	5,460
Additions to investments in unconsolidated affiliates	—	(1,910)	(36,365)	—	(38,275)
Cash paid for acquisitions, net of cash acquired	—	(729,000)	(435,856)	—	(1,164,856)
Net cash used in investing activities of continuing operations	(4,619)	(740,009)	(657,266)	—	(1,401,894)
Net cash provided by (used in) investing activities of discontinued operations	—	(3,523)	190,000	—	186,477
Net cash used in investing activities	(4,619)	(743,532)	(467,266)	—	(1,215,417)
Cash flows from financing activities					
Net proceeds from revolving credit facility	359,219	7,000	—	—	366,219
Repayments of revolving credit facility	(170,000)	(7,000)	—	—	(177,000)
Net proceeds from GulfTerra Holding term credit facility	—	530,529	(393)	—	530,136
Repayment of GulfTerra Holding term credit facility	—	(375,000)	—	—	(375,000)
Net proceeds from senior secured acquisition term loan	233,236	—	—	—	233,236
Net proceeds from senior secured term loan	156,530	—	—	—	156,530
Net proceeds from issuance of long-term debt	423,528	—	—	—	423,528
Repayment of Argo term loan	—	—	(95,000)	—	(95,000)
Net proceeds from issuance of common units	150,159	—	—	—	150,159
Advances with affiliates	(1,103,585)	581,601	427,419	94,565	—
Contributions from general partner	4,095	—	—	—	4,095
Distributions to partners	(154,468)	—	—	—	(154,468)
Net cash provided by (used in) financing activities of continuing operations	(101,286)	737,130	332,026	94,565	1,062,435
Net cash used in financing activities of discontinued operations	—	(3)	—	—	(3)
Net cash provided by (used in) financing activities	(101,286)	737,127	332,026	94,565	1,062,432
Increase (decrease) in cash and cash equivalents	$ 13,371	$ 15,553	$ (5,909)	$ —	23,015
Cash and cash equivalents at beginning of year					13,084
Cash and cash equivalents at end of year					$ 36,099

(1) Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW
Year Ended December 31, 2001

	Issuer	Non-guarantor Subsidiaries[1]	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
		(In thousands)			
Cash flows from operating activities					
Net income	$ 55,149	$ 1,308	$ 22,393	$(23,701)	$ 55,149
Less income from discontinued operations	—	1,308	(211)	—	1,097
Income from continuing operations	55,149	—	22,604	(23,701)	54,052
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	323	—	34,455	—	34,778
Asset impairment charge	—	—	3,921	—	3,921
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(8,449)	—	(8,449)
Distributions from unconsolidated affiliates	—	—	35,062	—	35,062
Loss on sales of long-lived assets	10,941	—	426	—	11,367
Amortization of debt issuance cost	3,290	318	—	—	3,608
Other noncash items	270	—	274	—	544
Working capital changes, net of effects of acquisitions and non-cash transactions	(10,145)	385	(42,707)	—	(52,467)
Net cash provided by continuing operations	59,828	703	45,586	(23,701)	82,416
Net cash provided by discontinued operations	—	4,296	672	—	4,968
Net cash provided by operating activities	59,828	4,999	46,258	(23,701)	87,384
Cash flows from investing activities					
Development expenditures for oil and natural gas properties	—	—	(2,018)	—	(2,018)
Additions to property, plant and equipment	(896)	—	(507,451)	—	(508,347)
Proceeds from the sale and retirement of assets	89,162	—	19,964	—	109,126
Additions to investments in unconsolidated affiliates	—	—	(1,487)	—	(1,487)
Cash paid for acquisitions, net of cash acquired	—	—	(28,414)	—	(28,414)
Net cash provided by (used in) investing activities of continuing operations	88,266	—	(519,406)	—	(431,140)
Net cash used in investing activities of discontinued operations	—	(67,367)	(1,193)	—	(68,560)
Net cash provided by (used in) investing activities	88,266	(67,367)	(520,599)	—	(499,700)
Cash flows from financing activities					
Net proceeds from revolving credit facility	559,994	—	—	—	559,994
Repayments of revolving credit facility	(581,000)	—	—	—	(581,000)
Net proceeds from issuance of long-term debt	243,032	—	—	—	243,032
Advances with affiliates	(515,198)	13,563	477,934	23,701	—
Net proceeds from issuance of common units	286,699	—	—	—	286,699
Redemption of Series B preference units	(50,000)	—	—	—	(50,000)
Contributions from general partner	2,843	—	—	—	2,843
Distributions to partners	(105,923)	—	(486)	—	(106,409)
Net cash provided by (used in) financing activities of continuing operations	(159,553)	13,563	477,448	23,701	355,159
Net cash provided by financing activities of discontinued operations	—	49,960	—	—	49,960
Net cash provided by (used in) financing activities	(159,553)	63,523	477,448	23,701	405,119
Increase (decrease) in cash and cash equivalents	$ (11,459)	$ 1,155	$ 3,107	$ —	(7,197)
Cash and cash equivalents at beginning of year					20,281
Cash and cash equivalents at end of year					$ 13,084

[1] Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

17. Supplemental Oil and Natural Gas Information (Unaudited):

General

This footnote discusses our oil and natural gas production activities for the year 2001. The years 2003 and 2002 are not presented since these operations are not a significant part of our business as defined by SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*, and we do not expect it to become significant in the future.

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001. Estimates of our reserves at December 31, 2001 have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our policy is to recognize proved reserves only when economic producibility is supported by actual production. As a result, no proved reserves were booked with respect to any of our producing fields in the absence of actual production. Proved developed reserves are proved reserve volumes that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserve volumes that are expected to be recovered from new wells on undrilled acreage or from existing wells where a significant expenditure is required for recompletion. Reference Rules 4-10(a)(2)(i), (ii), (iii), (3) and (4) of Regulation S-X, for detailed definitions of proved reserves, which can be found at the SEC's website, *http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.*

Estimates of reserve quantities are based on sound geological and engineering principles, but, by their very nature, are still estimates that are subject to substantial upward or downward revision as additional information regarding producing fields and technology becomes available.

	Oil/Condensate MBbls[(1)]	Natural Gas MMcf[(1)]
Proved reserves — December 31, 2000	1,201	11,500
Revision of previous estimates	1,852	5,913
Production[(2)]	(345)	(4,172)
Proved reserves — December 31, 2001	2,708	13,241
Proved developed reserves December 31, 2001[(2)]	2,350	10,384

(1) Includes our overriding royalty interest in proved reserves on Garden Banks Block 73 and the Prince Field.

(2) Includes our overriding royalty interest in proved reserves of 1,341 MBbls of oil and 1,659 MMcf of natural gas on our Prince Field, which began production in 2001. These reserves were not included in proved reserves prior to 2001 because, consistent with our policy, economic producibility had not been supported by actual production. Also, we had increases in estimated proved reserves relating to our producing properties, primarily at our West Delta 35 field. Actual production in the Prince Field for 2001 was 37 MBbls of oil and 32 MMcf of natural gas.

The following are estimates of our total proved developed and proved undeveloped reserves of oil and natural gas by producing property as of December 31, 2001.

	Oil (barrels)		Natural Gas (Mcf)	
	Proved Developed	Proved Undeveloped	Proved Developed	Proved Undeveloped
	(In thousands)			
Garden Banks Block 72	277	—	1,900	—
Garden Banks Block 117	1,065	—	1,556	—
Viosca Knoll Block 817	12	—	2,216	2,437
West Delta Block 35	13	—	3,473	—
Prince Field	983	358	1,239	420
Total	2,350	358	10,384	2,857

In general, estimates of economically recoverable oil and natural gas reserves and of the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs and future plugging and abandonment costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Estimates with respect to proved undeveloped reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. A significant portion of our reserves is based upon volumetric calculations.

Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is calculated and presented in accordance with SFAS No. 69. Accordingly, future cash inflows were determined by applying year-end oil and natural gas prices, as adjusted for fixed price contracts in effect, to our estimated share of future production from proved oil and natural gas reserves. The average prices utilized in the calculation of the standardized measure of discounted future net cash flows at December 31, 2001, were $16.75 per barrel of oil and $2.62 per Mcf of natural gas. Actual future prices and costs may be materially higher or lower. Future production and development costs were computed by applying year-end costs to future years. As we are not a taxable entity, no future income taxes were provided. A prescribed 10 percent discount factor was applied to the future net cash flows.

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies. In the table following, the amounts of future production costs have been restated to include platform access fees paid to our platform segment. See note 2 to the table for further discussion of the impact of such fees on our consolidated standardized measure of discounted future net cash flows.

	December 31, 2001
	(In thousands)
Future cash inflows[1]	$ 80,603
Future production costs[2]	(19,252)
Future development costs	(10,530)
Future net cash flows	50,821
Annual discount at 10% rate	(11,761)
Standardized measure of discounted future net cash flows	$ 39,060

(1) Our future cash inflows include estimated future receipts from our overriding royalty interest in our Prince Field and Garden Banks Block 73. Since these are overriding royalty interests, we do not participate in the production or development costs for these fields, but do include their proved reserves, production volumes and future cash inflows in our data.

(2) Our future production costs include platform access fees paid by our oil and natural gas production business to affiliated entities included in our platform services segment. Such platform access fees are eliminated in our consolidated financial statements. The future platform access fees paid to our platform segment were $4,960 for 2001. On a consolidated basis, our standardized measure of discounted future net cash flows was $43,789 for 2001.

Estimated future net cash flows for proved developed and proved undeveloped reserves as of December 31, 2001, are as follows:

	Proved Developed	Proved Undeveloped	Total
		(In thousands)	
Undiscounted estimated future net cash flows from proved reserves before income taxes	$40,518	$10,303	$50,821
Present value of estimated future net cash flows from proved reserves before income taxes, discounted at 10%	$31,003	$ 8,057	$39,060

The following are the principal sources of change in the standardized measure:

	2001
	(In thousands)
Beginning of year	$ 77,706
Sales and transfers of oil and natural gas produced, net of production costs	(34,834)
Net changes in prices and production costs	(55,657)
Extensions, discoveries and improved recovery, less related costs	—
Oil and natural gas development costs incurred during the year	2,018
Changes in estimated future development costs	535
Revisions of previous quantity estimates	38,090
Accretion of discount	7,771
Changes in production rates, timing and other	3,431
End of year	$ 39,060

Development, Exploration, and Acquisition Expenditures

The following table details certain information regarding costs incurred in our development, exploration, and acquisition activities during the year ended December 31:

	2001
	(In thousands)
Development costs	$2,018
Capitalized interest	—
Total capital expenditures	$2,018

In the year presented, we elected not to incur any costs to develop our proved undeveloped reserves.

Capitalized Costs

Capitalized costs relating to our natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows as of December 31:

	2001
	(In thousands)
Oil and natural gas properties	
Proved properties	$ 54,609
Wells, equipment, and related facilities	104,766
	159,375
Less accumulated depreciation, depletion and amortization	108,307
	$ 51,068

Results of operations

Results of operations from producing activities were as follows at December 31:

	2001
	(In thousands)
Natural gas sales	$18,248
Oil, condensate, and liquid sales	8,062
Total operating revenues	26,310
Production costs[1]	16,367
Depreciation, depletion and amortization	7,567
Results of operations from producing activities	$ 2,376

(1) These production costs include platform access fees paid to affiliated entities included in our platform services segment. Such platform access fees, which were approximately $10 million in the year presented, are eliminated in our consolidated financial statements.

18. Supplemental Quarterly Financial Information:

	Quarter Ended (Unaudited)				
	March 31	June 30	September 30	December 31	Year
	(In thousands, except per unit data)				
2003					
Operating revenues[1]	$230,095	$237,031	$213,831	$190,532	$871,489
Operating income	75,107	77,886	92,079	69,391	314,463
Income from continuing operations	40,525	49,297	60,213	11,414	161,449
Cumulative effect of accounting change	1,690	—	—	—	1,690
Net income	42,215	49,297	60,213	11,414	163,139
Income allocation					
Series B unitholders	$ 3,876	$ 3,898	$ 4,018	$ —	$ 11,792
General partner					
Income from continuing operations	$ 14,860	$ 15,856	$ 18,031	$ 20,667	$ 69,414
Cumulative effect of accounting change	17	—	—	—	17
	$ 14,877	$ 15,856	$ 18,031	$ 20,667	$ 69,431
Common unitholders					
Income from continuing operations	$ 17,454	$ 24,160	$ 31,337	$ (7,796)	$ 65,155
Cumulative effect of accounting change	1,340	—	—	—	1,340
	$ 18,794	$ 24,160	$ 31,337	$ (7,796)	$ 66,495
Series C unitholders					
Income from continuing operations	$ 4,335	$ 5,383	$ 6,827	$ (1,457)	$ 15,088
Cumulative effect of accounting change	333	—	—	—	333
	$ 4,668	$ 5,383	$ 6,827	$ (1,457)	$ 15,421
Basic earnings per common unit					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.63	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	—	—	—	0.03
Net income	$ 0.43	$ 0.50	$ 0.63	$ (0.14)	$ 1.33
Diluted earnings per common unit[2]					
Income from continuing operations	$ 0.40	$ 0.50	$ 0.62	$ (0.14)	$ 1.30
Cumulative effect of accounting change	0.03	—	—	—	0.02
Net income	$ 0.43	$ 0.50	$ 0.62	$ (0.14)	$ 1.32
Distributions declared and paid per common unit	$ 0.675	$ 0.675	$ 0.700	$ 0.710	$ 2.760
Basic weighted average number of common units outstanding	44,104	48,005	50,072	57,562	49,953
Diluted weighted average number of common units outstanding	44,104	48,476	50,385	57,855	50,231

(1) Since November 2002, when we acquired the Typhoon Oil Pipeline, we have recognized revenue attributable to it using the "gross" method, which means we record as "revenues" all oil that we purchase from our customers at an index price less an amount that compensates us for our service and we record as "cost of oil" that same oil which we resell to those customers at the index price. We believe that a "net" presentation is more appropriate than a "gross" presentation and is consistent with how we evaluate the performance of the Typhoon Oil Pipeline. Based on our review of the accounting literature, we believe that generally accepted accounting principles permit us to use the "net" method, and accordingly we have presented the results of Typhoon Oil "net" for all periods. To reflect this reclassification, operating revenues have been reduced by $48.8 million, $73.1 million and $69.8 million for the quarters ended March 31, June 30 and September 30 of 2003. This change does not affect operating income or net income.

(2) As a result of the loss allocated to our common unitholders during the quarter ended December 31, 2003, the basic and diluted earnings per common units are the same.

	Quarter Ended (Unaudited)				
	March 31	June 30	September 30	December 31	Year
	(In thousands, except per unit data)				
2002					
Operating revenues[1]	$ 61,544	$120,489	$122,249	$153,108	$457,390
Operating income	22,712	45,777	41,936	50,385	160,810
Income from continuing operations	14,741	28,685	23,346	25,780	92,552
Income from discontinued operations	4,385	60	456	235	5,136
Net income	19,126	28,745	23,802	26,015	97,688
Income allocation					
Series B unitholders	$ 3,552	$ 3,630	$ 3,693	$ 3,813	$ 14,688
General partner					
Income from continuing operations	$ 8,691	$ 10,799	$ 10,755	$ 11,837	$ 42,082
Income from discontinued operations	44	—	5	2	51
	$ 8,735	$ 10,799	$ 10,760	$ 11,839	$ 42,133
Common unitholders					
Income from continuing operations	$ 2,498	$ 14,256	$ 8,898	$ 8,623	$ 34,275
Income from discontinued operations	4,341	60	451	233	5,085
	$ 6,839	$ 14,316	$ 9,349	$ 8,856	$ 39,360
Series C unitholders	$ —	$ —	$ —	$ 1,507	$ 1,507
Basic and diluted earnings per common unit					
Income from continuing operations	$ 0.06	$ 0.33	$ 0.20	$ 0.21	$ 0.80
Income from discontinued operations	0.11	—	0.01	—	0.12
Net income	$ 0.17	$ 0.33	$ 0.21	$ 0.21	$ 0.92
Distributions declared and paid per common unit	$ 0.625	$ 0.650	$ 0.650	$ 0.675	$ 2.600
Weighted average number of common units outstanding	39,941	42,842	44,130	44,069	42,814

(1) Operating revenues for the quarter ended December 31, 2002, have been reduced by $10.5 million to reflect the reclassification of Typhoon Oil Pipeline's cost of oil.

REPORT OF INDEPENDENT AUDITORS

To the Unitholders of GulfTerra Energy Partners, L.P.
and the Board of Directors and Stockholders of
GulfTerra Energy Company, L.L.C., as General Partner:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income and changes in accumulated other comprehensive income (loss), partners' capital and cash flows present fairly, in all material respects, the financial position of GulfTerra Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership'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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership has entered into a definitive agreement to merge with Enterprise Products Partners L.P.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for asset retirement obligations and its reporting for gains or losses resulting from the extinguishment of debt effective January 1, 2003.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for the impairment or disposal of long lived assets effective January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas
March 12, 2004

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2003

Each exhibit identified below is filed as part of this report. Exhibits not incorporated by reference to a prior filing 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.

Exhibit Number	Description
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).
2.B.1	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).
2.C	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).
2.D	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).
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 (Exhibit 4.1 to our Form 8-K dated May 10, 1999); Seventh Supplemental Indenture dated as of June 10, 2002, by and between El Paso and JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.2 to our Registration Statement on Form S-4 filed July 17, 2002; Eighth Supplemental Indenture dated as of June 26, 2002, between El Paso and JP Morgan Chase Bank (formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.A to our Form 8-K filed June 26, 2002).
4.B	Purchase Contract Agreement (including forms of Units and Stripped Units), dated as of June 26, 2002, between the Company and JPMorgan Chase Bank, as Purchase Contract Agent (Exhibit 4.B to our Form 8-K filed June 26, 2002).

Exhibit Number	Description
4.C	Registration Rights Agreement dated as of June 10, 2002, between El Paso and Credit Suisse First Boston Corporation (Exhibit 4.3 to our Registration Statement on Form S-4 filed July 17, 2002).
4.D	Pledge Agreement, dated as of June 26, 2002, among the Company, The Bank of New York, as Collateral Agent, Custodial Agent and Securities Intermediary, and JPMorgan Chase Bank, as Purchase Contract Agent (Exhibit 4.C to our Form 8-K filed June 26, 2002).
4.E	Remarketing Agreement, dated as of June 26, 2002, among the Company, JPMorgan Chase Bank, as Purchase Contract Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent (Exhibit 4.D to our Form 8-K filed June 26, 2002).
10.A	$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 El Paso Corporation's Form 8-K filed April 18, 2003).
*10.A.1	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.
*10.A.2	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.
10.A.3	Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August , 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.
10.B	$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 8K filed April 18, 2003).
10.C	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.D	Omnibus Compensation Plan dated January 1, 1992; Amendment No. 1 effective as of April 1, 1998 to the Omnibus Compensation Plan; Amendment No. 2 effective as of August 1, 1998 to the Omnibus Compensation Plan; Amendment No. 3 effective as of December 3, 1998 to the Omnibus Compensation Plan; and Amendment No. 4 effective as of January 20, 1999 to the Omnibus Compensation Plan. (Exhibit 10.C to our 1998 10-K); Amendment No. 5 effective as of August 1, 2001 to the Omnibus Compensation Plan (Exhibit 10.C.1 to our 2001 Third Quarter Form 10-Q).

Exhibit Number	Description
†10.E	1995 Incentive Compensation Plan Amended and Restated effective as of December 3, 1998 (Exhibit 10.D to our 1998 Form 10-K).
*†10.F	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003.
†10.G	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.F to our 1998 10-K) and Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.F.1 to our 1999 Second Quarter Form 10-Q); 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).
*†10.H.1	Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors.
†10.I	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our 1998 Third Quarter Form 10-Q); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan; Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.G.1 to our 1998 10-K).
†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 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).
*†10.K.1	Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan.
†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).
†10.M	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our 1998 Third Quarter Form 10-Q); 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).
†10.N	Deferred Compensation Plan Amended and Restated as of June 13, 2002 (Exhibit 10.M to our 2002 Second Quarter Form 10-Q); Amendment No. 1 effective as of November 7, 2002 to the Deferred Compensation Plan (Exhibit 10.M.1 to the 2002 Form 10-K).

Exhibit Number	Description
†10.O	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.O to our 1998 Third Quarter Form 10-Q); 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 and 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.P	2004 Key Executive Severance Protection Plan effective as of March 9, 2004.
†10.Q	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our 1998 Third Quarter Form 10-Q); 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).
*†10.Q.1	Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan.
†10.R	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.S	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.Q to EPNG's 1997 Form 10-K).
†10.T	Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.R to our 1999 Third Quarter Form 10-Q); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to our 2000 Second Quarter Form 10-Q).
†10.U	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 and 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.V	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, Commission File No. 1-14365); 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).
*†10.V.1	Amendment No. 2 effective as of December 31, 2003 to the El Paso Production Companies Long-Term Incentive Plan.
†10.W	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, Commission File No. 1-14365); 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).
*†10.W.1	Amendment No. 4 to Supplement No. 1 effective as of October 1, 2003.
*†10.W.2	Amendment No. 5 to Supplement No. 1 effective as of February 2, 2004.
†10.X	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).

Exhibit Number	Description
†10.X.1	Promissory Note dated May 30, 1997, made by William A. Wise to El Paso (Exhibit 10.R to EPNG's Form 10-Q, filed May 15, 1998); Amendment to Promissory Note dated November 20, 1997 (Exhibit 10.R to EPNG's 1998 First Quarter Form 10-Q). This Promissory Note dated May 30, 1997 was paid in full and El Paso transferred the lien on the residence to Mr. Wise's bank on March 19, 2003.
†10.Y	Pledge and Security Agreement, and Promissory Note, each dated August 16, 2001, by and between El Paso and William A. Wise. (Exhibit 10.CC to our 2001 Third Quarter Form 10-Q). The Promissory Note dated April 16, 2001 was paid in full and both the Promissory Note and Pledge and Security Agreement were cancelled on April 23, 2003.
†10.Z	Interim CEO Employment Agreement between Ronald L. Kuehn, Jr. and El Paso dated March 12, 2003 (Exhibit 10.Y to our 2003 First Quarter Form 10-Q).
†10.AA	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.BB	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.BB.1	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee.
*†10.CC	Letter Agreement dated January 6, 2004 between El Paso and Lisa A. Stewart.
†10.DD	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.EE	Form of Agreement to Restate Balance of Certain Compensation under the Alternative Benefits Program (previously filed as the Estate Enhancement Program) dated December 31, 2001, by and between El Paso and the named executives on the exhibit thereto, and Form of Promissory Note dated December 31, 2001, in favor of El Paso by trusts established by named executives, loan amounts, and interest rates (Exhibit 10.AA to our 2001 Form 10-K).
10.FF	Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P. effective as of August 31, 2000 (Exhibit 10.FF to our 2002 Third Quarter Form 10-Q); First Amendment to the Second Amended and Restated Agreement of Limited Partnership of GulfTerra Energy Partners, L.P. (Exhibit 10.CC.1 to our 2002 Form 10-K).
10.GG	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).
*10.HH	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 Number	Description
10.II	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.JJ	Amendment No. 2 dated April 30, 2003 to the $1,200,000,000 Senior Secured Interim Term Credit and Security Agreement dated as of March 13, 2003 (Exhibit 10.DD.1 to our 2003 First Quarter Form 10-Q).
10.KK	Second Amended and Restated Guaranty Agreement dated as of March 29, 2002, made by El Paso, as guarantor (Exhibit 10.EE.2 to our 2002 Third Quarter Form 10-Q).
10.LL	Amended and Restated Participation Agreement, dated as of April 12, 2002, by and among El Paso, Limestone Electron Trust, Limestone Electron, Inc, Credit Suisse First Boston (USA), Inc., El Paso Chaparral Holding Company, El Paso Chaparral Holding II Company, El Paso Chaparral Investor, L.L.C., El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., Mesquite Investors, L.L.C., El Paso Electron Overfund Trust, El Paso Electron Share Trust, Electron Trust, Wilmington Trust Company and The Bank Of New York (Exhibit 10.BB to our 2002 Third Quarter Form 10-Q).
10.LL.1	Fifth Amended and Restated Limited Liability Company Agreement of Chaparral Investors, L.L.C., dated as of April 12, 2002 (Exhibit 10.BB.1 to our 2002 Third Quarter Form 10-Q).
10.LL.2	Third Amended And Restated Limited Liability Company Agreement Of Mesquite Investors, L.L.C., dated as of March 27, 2000 (Exhibit 10.BB.2 to our 2002 Third Quarter Form 10-Q).
10.LL.3	Amended and Restated Management Agreement dated as of March 27, 2000, among El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., Mesquite Investors, L.L.C., and El Paso Chaparral Investors, L.L.C. (Exhibit 10.BB.3 to our 2002 Third Quarter Form 10-Q).
10.LL.4	Third Amended and Restated Trust Agreement of Limestone Electron Trust, dated as of April 12, 2002, by Wilmington Trust Company, El Paso, as holder of the El Paso Interest, Electron Trust (Exhibit 10.BB.4 to our 2002 Third Quarter Form 10-Q).
10.LL.5	Indenture, dated as of April 26, 2002, among Limestone Electron Trust, Limestone Electron, Inc., The Bank Of New York, and El Paso as guarantor (Exhibit 10.BB.5 to our 2002 Third Quarter Form 10-Q).
10.MM	Amended and Restated Participation Agreement, dated as of April 24, 2002, by and among El Paso, EPED Holding Company, EPED B Company, Jewel Investor, L.L.C., Gemstone Investor Limited, Gemstone Investor, Inc., Topaz Power Ventures, L.L.C., Emerald Finance, L.L.C., Citrine FC Company, Garnet Power Holdings, L.L.C., Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., Amethyst Power Holdings, L.L.C., Aquamarine Power Holdings, L.L.C., Peridot Finance S.à r.l., Gemstone Administração Ltda., El Paso Gemstone Share Trust, Wilmington Trust Company, and The Bank of New York (Exhibit 10.CC to our 2002 Third Quarter Form 10-Q).
10.MM.1	Shareholder Agreement dated as of April 24, 2002, by and among Gemstone Investor Limited, Jewel Investor, L.L.C. and El Paso, and The Bank of New York (Exhibit 10.CC.1 to our 2002 Third Quarter Form 10-Q).
10.MM.2	Second Amended and Restated Limited Liability Company Agreement of Diamond Power Ventures, L.L.C. dated as of April 24, 2002 (Exhibit 10.CC.2 to our 2002 Third Quarter Form 10-Q).
10.MM.3	Second Amended and Restated Limited Liability Company Agreement of Topaz Power Ventures, L.L.C. dated as of April 24, 2002 (Exhibit 10.CC.3 to our 2002 Third Quarter Form 10-Q).
10.MM.4	Second Amended and Restated Limited Liability Company Agreement of Garnet Power Holdings, L.L.C., dated as of April 24, 2002 (Exhibit 10.CC.4 to our 2002 Third Quarter Form 10-Q).

Exhibit Number	Description
10.MM.5	Indenture dated as of May 9, 2002, among Gemstone Investor Limited, Gemstone Investor, Inc., The Bank Of New York, and El Paso as guarantor (Exhibit 10.CC.5 to our 2002 Third Quarter Form 10-Q).
10.MM.6	Management Agreement, dated as of November 1, 2001, by and among Gemstone Administração Ltda., Garnet Power Holdings, L.L.C. Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., and EPED B Company (Exhibit 10.CC.6 to our 2002 Third Quarter Form 10-Q).
10.NN	Fourth Amended and Restated Partnership Agreement of Clydesdale Associates, L.P. dated as of July 19, 2002 (Exhibit 10.DD to our 2002 Third Quarter Form 10-Q).
10.NN.1	Amended and Restated Sponsor Subsidiary Credit Agreement dated April 16, 2003 among Noric Holdings, L.L.C. as borrower, and the Other Sponsor Subsidiaries Party as Co-Obligators, Mustang Investors, L.L.C., as Sponsor Subsidiary Lender, and Clydesdale Associates, L.P. as Subordinated Note Holder, and Wilmington Trust Company, as Sponsor Subsidiary Collateral Agent, and Citicorp North America, Inc. as Mustang Collateral Agent; Fifth Amended and Restated El Paso Agreement dated April 16, 2003 by El Paso Corporation, in favor of Mustang Investors, L.L.C. and the Other Indemnified Persons; Amended and Restated Guaranty Agreement dated as of April 16, 2003 made by El Paso Corporation, as Guarantor in favor of Each Sponsor Subsidiary, Noric, L.L.C., Noric, L.P. and each Controlled Business as Beneficiaries; Definitions Agreement dated as of April 16, 2003 among El Paso Corporation and Noric Holdings, L.L.C. and the Other Sponsor Subsidiaries Party thereto, Mustang Investors, L.L.C., and Clydesdale Associates, L.P. and the Other Parties Named therein (Exhibit 10.GG to our 2003 First Quarter Form 10-Q).
10.NN.2	Amended and Restated Guaranty Agreement, dated as of July 19, 2002, made by El Paso, as guarantor, in favor of, severally, each Sponsor Subsidiary, Noric, Noric LP and each Controlled Business (Exhibit 10.DD.2 to our 2002 Third Quarter Form 10-Q).
10.OO	Third Amended and Restated Company Agreement of Trinity River Associates, L.L.C. dated as of March 29, 2002, by and between Sabine River Investors, L.L.C., and Red River Investors, L.L.C. (Exhibit 10.EE to our 2002 Third Quarter Form 10-Q).
10.OO.1	Second Amended and Restated Sponsor Subsidiary Credit Agreement dated as of March 29, 2002, Sabine River Investors, L.L.C., as Borrower, each Sponsor Subsidiary, Trinity River Associates, L.L.C., as Lender, and Wilmington Trust Company, as Collateral Agent for Trinity (Exhibit 10.EE.1 to our Third Quarter Form 10-Q).
10.OO.2	Second Amended and Restated Guaranty Agreement dated as of March 29, 2002, made by El Paso, as guarantor (Exhibit 10.EE.2 to our 2002 Third Quarter Form 10-Q).
*21	Subsidiaries of El Paso.
*23.A	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
*23.B	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (GulfTerra).
*23.C	Consent of Huddleston & Co., Inc.
*23.D	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 our 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 30th day of September 2004.

EL PASO CORPORATION
Registrant

By /s/ DOUGLAS 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
/s/ DOUGLAS L. FOSHEE (Douglas L. Foshee)	President, Chief Executive Officer and Director (Principal Executive Officer)	September 30, 2004
/s/ D. DWIGHT SCOTT (D. Dwight Scott)	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	September 30, 2004
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	September 30, 2004
/s/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Chairman of the Board and Director	September 30, 2004
/s/ JOHN M. BISSELL (John M. Bissell)	Director	September 30, 2004
/s/ JUAN CARLOS BRANIFF (Juan Carlos Braniff)	Director	September 30, 2004
/s/ JAMES L. DUNLAP (James L. Dunlap)	Director	September 30, 2004
/s/ ROBERT W. GOLDMAN (Robert W. Goldman)	Director	September 30, 2004
/s/ ANTHONY W. HALL, JR. (Anthony W. Hall, Jr.)	Director	September 30, 2004

Signature	Title	Date
/s/ THOMAS R. HIX (Thomas R. Hix)	Director	September 30, 2004
/s/ WILLIAM H. JOYCE (William H. Joyce)	Director	September 30, 2004
/s/ J. CARLTON MACNEIL, JR. (J. Carlton MacNeil, Jr.)	Director	September 30, 2004
/s/ J. MICHAEL TALBERT (J. Michael Talbert)	Director	September 30, 2004
/s/ MALCOLM WALLOP (Malcolm Wallop)	Director	September 30, 2004
/s/ JOHN L. WHITMIRE (John L. Whitmire)	Director	September 30, 2004
/s/ JOE B. WYATT (Joe B. Wyatt)	Director	September 30, 2004