EL PASO CORP/DE
Form 10-K/A
April 08, 2005

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

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

(Mark One)
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ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004
OR

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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 þ No o.

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. þ

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

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

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

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

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

Documents Incorporated by Reference

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

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

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

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

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

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EXPLANATORY NOTE

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

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

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PART I

ITEM 1. BUSINESS

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

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

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

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

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Business Segments

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

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

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

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

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

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

Regulated Business Pipelines Segment

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

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

Wholly Owned Interstate Transmission Systems

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

of Atlanta and
Birmingham.

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

[1] Includes throughput transported on behalf of affiliates.

(2) This capacity reflects winter-sustainable west-flow capacity and 800 MMcf/d of east-end delivery capacity.
(3) This capacity was placed in service on December 1, 2004. Compression was added and placed in service on January 31, 2005, which increased the design capacity to 576 MMcf/d.

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

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

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Partially Owned Interstate Transmission Systems

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

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

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

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

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

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

Underground Natural Gas Storage Entities

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

Storage Entity	As of December 31, 2004 Ownership Interest	Storage Capacity(1)	Location
	(Percent)	(Bcf)	

Bear Creek Storage	100	58	Louisiana
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage(2)	50	13	Michigan
Young Gas Storage(2)	48	6	Colorado

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

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

LNG Facility

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

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Regulatory Environment

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

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

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

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

Markets and Competition

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

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

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

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

Contract Expirations

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

Transmission System	Customer Information	Contract Information	Competition
TGP	Approximately 432 firm and interruptible customers Major Customers: None of which individually represents more than 10 percent of revenues	Approximately 464 firm contracts 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. In the offshore areas of the Gulf of Mexico, factors such as the distance of the supply field from the pipeline, relative basis pricing of the pipeline receipt options, costs of intermediate gathering or required processing of the gas all influence determinations of whether gas is ultimately attached to our system.
ANR	Approximately 259 firm and interruptible customers Major Customer: We Energies (909 BBtu/d)	Approximately 570 firm contracts Weighted average remaining contract term of approximately three years.	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

	Contract terms expire in 2005-2010.	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. ANR also competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR s principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.

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

[1] Approximately 1,564 MMcf/d currently under contract is subject to early termination in August 2006 provided customers give timely notice of an intent to terminate. If all of these rights were exercised, the weighted average remaining contract term would decrease to approximately three years.
[2] Reflects the impact of an agreement we entered into, subject to FERC approval, to extend 750 MMCf/d of SoCal s current capacity, effective September 1, 2006, for terms of three to five years.

Transmission System	Customer Information	Contract Information	Competition
SNG	Approximately 230 firm and interruptible customers	Approximately 203 firm contracts 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 (415 BBtu/d)	Contract terms expire in 2006-2013.	
	Scana Corporation (346 BBtu/d)	Contract terms expire in 2005-2019.	

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Transmission System	Customer Information	Contract Information	Competition
CIG	Approximately 112 firm and interruptible customers Major Customers: Public Service Company of Colorado (970 BBtu/d) (261 BBtu/d) (187 BBtu/d)	Approximately 191 firm contracts Weighted average remaining contract term of approximately five years. Contract term expires in 2007. Contract term expires in 2009-2014. Contract term expires in 2006.	CIG serves two major markets. Its on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its off-system market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. Competition for its on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for its off-system market consists of other interstate pipelines that are directly connected to its supply sources.
WIC	Approximately 49 firm and interruptible customers Major Customers: Williams Power Company (303 BBtu/d) Colorado Interstate Gas Company (247 BBtu/d) Western Gas Resources (235 BBtu/d) Cantera Gas Company (226 BBtu/d)	Approximately 47 firm contracts Weighted average remaining contract term of approximately six years. Contract terms expire in 2008-2013. Contract terms expire in 2005-2016. Contract terms expire in 2007-2013.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC s one Bcf/d Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply and can readily be expanded as supply increases. Currently, there are two other interstate pipelines that transport limited volumes out of this basin.

		Contract terms expire in 2012-2013.	
MPC	Approximately 14 firm and interruptible customers	Approximately nine firm contracts Weighted average remaining contract term of approximately two years.	MPC faces competition from existing pipelines, a newly proposed pipeline, LNG projects and alternative energy sources that generate electricity such as hydroelectric power, nuclear, coal and fuel oil.
	Major Customers:		
	Texaco Natural Gas Inc. (185 BBtu/d)		
	Burlington Resources Trading Inc. (76 BBtu/d)	Contract term expires in 2007.	
	Los Angeles Department of Water and Power	Contract term expires in 2007.	
	(50 BBtu/d)	Contract term expires in 2007.	

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

Non-regulated Business Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in the United States and Brazil. In the United States, as of December 31, 2004, we controlled over 3 million net acres of leasehold acreage through our operations in 20 states, including Louisiana, New Mexico, Texas, Oklahoma, Alabama and Utah, and through our offshore operations in federal and state waters in the Gulf of Mexico. During 2004, daily equivalent natural gas production averaged approximately 814 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2004, were approximately 2.2 Tcfe.

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

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

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

Natural Gas, Oil and Condensate and Natural Gas Liquids Reserves

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

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natural gas equivalents of 145,507 MMcfe, all net to our ownership interests. Our estimated proved reserves as of December 31, 2004, and our 2004 production are as follows:

Net Proved Reserves[1]

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

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

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

Net Proved Reserves[1]

	Natural Gas	Oil/ Condensate	NGL	Total	
	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(Percent)
United States					
Producing	1,085,581	12,507	10,588	1,224,152	62
Non-Producing	201,696	7,134	1,355	252,626	13
Undeveloped	436,564	7,690	1,258	490,253	25
Total proved	1,723,841	27,331	13,201	1,967,031	100
Brazil					
Producing	29,239	1,375		37,488	18
Non-Producing	24,988	1,238		32,415	15
Undeveloped	14,516	21,558		143,866	67
Total proved	68,743	24,171		213,769	100
Worldwide					

Producing	1,114,820	13,882	10,588	1,261,640	58
Non-Producing	226,684	8,372	1,355	285,041	13
Undeveloped	451,080	29,248	1,258	634,119	29
Total proved	1,792,584	51,502	13,201	2,180,800	100

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

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

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating

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underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of reasonable certainty be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreage and Wells

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

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

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

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

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

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

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

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

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

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

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

Total	24	82	41	301	273	516

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

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

Net Production, Sales Prices, Transportation and Production Costs

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

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

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

Total production cost	$	0.71	$	0.56	$	0.50

(1) Prices are stated before transportation costs.
(2) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

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Acquisition, Development and Exploration Expenditures

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

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

Total full cost pool expenditures	776	1,403	2,211
Non-full cost pool expenditures	14	18	49
Total capital expenditures	$ 790	$ 1,421	$ 2,260

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

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

Regulatory and Operating Environment

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

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

Our production business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to property or injuries to people. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain insurance coverage to limit exposure to potential losses resulting from these operating hazards.

Markets and Competition

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

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

Non-regulated Business Marketing and Trading Segment

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

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

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

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

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

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

Markets and Competition

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

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

Non-regulated Business Power Segment

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

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

Project	Country	El Paso Ownership Interest	Gross Capacity	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
		(Percent)	(MW)			
Brazil						
Araucaria(1)	Brazil	60	484	Copel	(2)	Natural Gas
Macae	Brazil	100	928	Petrobras(3)	2007(2)	Natural Gas
Manaus	Brazil	100	238	Manaus Energia(4)	2008	Oil
Porto Velho(1)	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro	Brazil	100	158	Manaus Energia(4)	2008	Oil
Asia						
Fauji(1)	Pakistan	42	157	Pakistan Water and Power	2029	Natural Gas
Habibullah(1)	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
KIECO(1)	South Korea	50	1,720	KEPCO	2020	Natural Gas
Meizhou Wan(1)	China	26	734	Fujian Power	2025	Coal
Haripur(1)	Bangladesh	50	116	Bangladesh Power	2014	Natural Gas
PPN(1)(5)	India	26	325	Tamil Nadu	2031	Naphtha/Natural Gas
Saba(1)	Pakistan	94	128	Pakistan Water and Power	2029	Oil
Sengkang(1)	Indonesia	48	135	PLN	2022	Natural Gas
Central and other South America						

Aguaytia[1]	Peru	24	155	Various	2005, 2006	Natural Gas
Fortuna[1]	Panama	25	300	Union Fenosa	2005, 2008	Hydroelectric
Itabo[1]	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Nejapa	El Salvador	87	144	AES and PPL	2005	Oil
Europe						
Enfield[1]	United Kingdom	25	378	Spot Market		Natural Gas
EMA[1]	Hungary	50	69	Dunaferr Energy Services	2016	Natural Gas/Oil

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

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

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

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

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

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

(1) These power facilities are reflected as investments in unconsolidated affiliates in our financial statements.
(2) These power facilities (referred to as merchant plants) do not have long-term power purchase agreements with third parties. Our Marketing and Trading segment sells the power that a majority of these facilities generate to the

wholesale power market.

(3) These plants have Board approval for sale and are targeted to be sold in the first half of 2005. We have executed sales agreements on the Pawtucket and San Joaquin facilities.

(4) These plants were sold in the first quarter of 2005.

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

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

Regulatory Environment & Markets and Competition

International. Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of these countries have recently developed

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or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures are subject to change (including differing interpretations) over time.

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

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

Non-regulated Business Field Services Segment

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

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

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

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

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

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

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

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

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

Other Operations and Assets

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

Corporate Activities

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

Discontinued Operations

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

Environmental

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

Employees

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

Executive Officers of the Registrant

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

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

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

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

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

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

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

Available Information

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

ITEM 2. PROPERTIES

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

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

ITEM 3. LEGAL PROCEEDINGS

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

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

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

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

Environmental Proceedings

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PART II

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

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

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

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

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

Odd-lot Sales Program

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

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ITEM 6. SELECTED FINANCIAL DATA

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

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

(1) During the completion of the financial statements for the year ended December 31, 2004, we identified an error in the manner in which we had originally adopted the provisions of SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, in 2002. Upon adoption of these standards, we incorrectly adjusted the cost of investments in unconsolidated affiliates and the cumulative effect of change in accounting principle for the excess of our share of the affiliates fair value of the net assets over their original cost, which we believed was negative goodwill. The amount originally recorded as a cumulative effect of accounting change was $154 million and related to our investments in Citrus Corporation, Portland Natural Gas, several Australian investments and an investment in the Korea Independent Energy Corporation. We subsequently determined that the amounts we adjusted were not negative goodwill, but rather amounts that should have been allocated to the

long-lived assets underlying our investments. As a result, we were required to restate our 2002 financial statements to reverse the amount we recorded as a cumulative effect of an accounting change on January 1, 2002. This adjustment also impacted a deferred tax adjustment and an unrealized loss we recorded on our Australian investments during 2002, requiring a further restatement of that year. The restatements also affected the investment, deferred tax liability and stockholders equity balances we reported as of December 31, 2002 and 2003. See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a further discussion of the restatements.

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

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

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

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

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

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

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

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

Overview

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

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

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

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

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

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

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

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

In 2005, we will continue to work to achieve our long-range goals by:

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

Capital Resources and Liquidity

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

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

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

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

(1) Includes proceeds from a $1.25 billion term loan under our new $3 billion credit agreement.

(2) Includes $850 million of repayments under our previous $3 billion revolving credit facility.

(3) Consists of $815 million of debt related to Utility Contract Funding and $72 million of debt related to Mohawk River Funding IV.

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

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

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

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

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

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

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

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

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

Overview of Cash Flow Activities for 2004 Compared to 2003

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

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

Continuing financing activities		
Payments to retire long-term debt and redeem preferred interests	2.5	4.1
Payments of revolving credit facilities	0.9	1.2
Dividends paid to common stockholders	0.1	0.2
Other	0.1	
	3.6	5.5
Total cash outflows	5.4	9.6
Net change in cash	$ 0.7	$ (0.2)

Cash From Continuing Operating Activities

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

Cash From Continuing Investing Activities

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

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

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

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

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

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

Cash From Continuing Financing Activities

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

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

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Contractual Obligations and Off-Balance Sheet Arrangements

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

Off-Balance Sheet Arrangements and Related Liabilities

Guarantees

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

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

Contractual Obligations

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

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

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

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

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

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

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

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

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

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

Commodity-based Derivative Contracts

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

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

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

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

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

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

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

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

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

(2) In the fourth quarter of 2004, we recorded a $227 million charge associated with the sale of our Cedar Brakes I and II subsidiaries and their related restructured power contracts. See Part II, Item 8, Financial Statements and

Supplementary Data, Notes 3 and 5 for additional information on this sale.

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

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

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

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

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

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

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

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

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

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

Results of Operations

Overview

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

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

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

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

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

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

As we refocused our activities on our core businesses by divesting of non-core businesses and restructuring our organization, we incurred losses and incremental costs in each year. During this period, we also resolved significant legal contingencies. These items are described in the table below. For a more detailed discussion of these factors and other items impacting our financial performance, see the individual segment

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and other results included in Part II, Item 8, Financial Statements and Supplementary Data, Notes 3 through 5, and 21.

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

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

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

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

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

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

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

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

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

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

Individual Segment Results

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

Regulated Business   Pipelines Segment

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

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

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

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

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

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

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

Operating Results

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

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

(1) Throughput volumes exclude volumes related to our equity investments in Portland Natural Gas Transmission System, EPIC Energy Australia Trust and Alliance Pipeline, which have been sold. In addition, volumes exclude

intrasegment activities. Throughput volumes include volumes related to our Mexico investments which were transferred from our Power segment effective January 1, 2004.

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

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

[1] Consists of costs of operations, electric and power purchase costs, shared services allocations and environmental costs.
[2] Consists of individually insignificant items across several of our pipeline systems.

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

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

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

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

Guardian Pipeline, which is owned in part by We Energies, currently provides a portion of We Energies firm transportation requirements and, therefore, directly competes with ANR for a portion of the markets in Wisconsin. This could impact ANR s existing customer contracts as well as future contractual negotiations with We Energies. In addition, ANR has entered into an agreement with a shipper to restructure one of its transportation contracts on its Southeast Leg as well as a related gathering contract. In March 2005, this

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restructuring was completed and ANR received approximately $26 million, which will be included in its earnings during the first quarter of 2005.

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

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

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

Expansion projects currently in process include:

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

Cheyenne Plains Gas Pipeline commenced free-flow operations in December 2004 and as of January 31, 2005 is fully in-service. Approval has already been received for Cheyenne Plains Phase II which will add an additional 179 MMcf/d of capacity that is scheduled to be available by the end of 2005.

CIG s Raton Basin 2005 Expansion will add 104 MMcf/d of capacity that is scheduled to be available by the end of 2005.

WIC expects to complete its Piceance lateral with capacity of 333 MMcf/d by the end of 2005.

EPNG s Line 1903 project, consisting of an expansion from Cadiz, California to Ehrenberg, Arizona, that is expected to be in-service by end of 2005 and will increase its capacity by 372 MMcf/d.

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

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

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

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

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

SNG filed a rate case in August 2004; settlement discussions with major customers are underway with a settlement conference to be scheduled in early 2005.

EPNG expected to file for new rates that would be effective January 2006.

CIG required to file for new rates that would be effective October 2006.

MPC expected to file for new rates that would be effective February 2007.

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

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

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

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Non-regulated Business Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and minimize our total administrative costs.

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

Reserves, Production and Costs

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

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

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions

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

Natural Gas

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

Oil

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

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

Operational Factors Affecting the Year Ended December 31, 2004

During 2004, our Production segment experienced the following:

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

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

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

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

Operating Results

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

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

	2004	Percent Variance	2003	Percent Variance	2002
Volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	244,857	(28)%	338,762	(28)%	470,082
Average realized prices including hedges ($/Mcf) (4)	$ 5.83	8%	$ 5.40	61%	$ 3.35
Average realized prices excluding hedges ($/Mcf) (4)	$ 5.90	7%	$ 5.51	74%	$ 3.17
Average transportation costs ($/Mcf)	$ 0.17	(6)%	$ 0.18		$ 0.18

Oil, condensate and NGL					
Volumes (MBbls)	8,818	(25)%	11,778	(28)%	16,462
Average realized prices including hedges ($/Bbl) [4]	$ 34.61	33%	$ 25.96	22%	$ 21.28
Average realized prices excluding hedges ($/Bbl) [4]	$ 34.75	30%	$ 26.64	25%	$ 21.38
Average transportation costs ($/Bbl)	$ 1.12	7%	$ 1.05	8%	$ 0.97
Total equivalent volumes(MMcfe)	297,766	(27)%	409,432	(28)%	568,852
Production costs($/Mcfe)					
Average lease operating costs	$ 0.60	43%	$ 0.42		$ 0.42
Average production taxes	0.11	(21)%	0.14	75%	0.08
Total production cost[1]	$ 0.71	27%	$ 0.56	12%	$ 0.50
Average general and administrative expenses ($/Mcfe)	$ 0.58	49%	$ 0.39	86%	$ 0.21
Unit of production depletion cost ($/Mcfe)	$ 1.69	29%	$ 1.31	28%	$ 1.02

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

(2) Includes ceiling test charges, restructuring charges, asset impairments and gains on asset sales.

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

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(4) Prices are stated before transportation costs.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Outlook for 2005

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

A total capital expenditure budget, including acquisitions, of approximately $900 million.

Daily production volumes to average in excess of 800 MMcfe/d.

A focus on cost control, operating efficiencies, and process improvements to keep our per unit cash operating costs between $1.25/ MMcfe and $1.40/ MMcfe.

Industry-wide increases in drilling costs and oilfield service costs that will require constant monitoring of capital spending programs.

Non-regulated Business Marketing and Trading Segment

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

2001 and 2002

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

2003 and 2004

A challenging trading environment with reduced liquidity, lower credit standing of industry participants and a general decline in the number of trading counterparties.

The ongoing liquidation of our historical trading portfolio.

The announcement in December 2003 that we would change our operations to primarily focus on the physical marketing of natural gas and oil produced in our Production segment.

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

Our Marketing and Trading segment s portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. The following is a

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discussion of the significant types of contracts used by our Marketing and Trading segment and how they impact our financial results:

Natural Gas Contracts

Production-related and other natural gas derivatives

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

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

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

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

Transportation-related contracts

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

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

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

The difference in natural gas prices at contractual receipt and delivery locations;

The capital needed to use this capacity (i.e. cash margins or letters of credit associated with the purchase and sale of natural gas to use the capacity); and

The capacity required to meet our other long term obligations.

Storage contracts

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

Power Contracts

Tolling contracts. We have two tolling contracts under which we supply fuel to power plants and receive the power generated