EL PASO CORP/DE
Form 10-K
February 28, 2008

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2007

OR

o **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 (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ.

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ.

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 29, 2007 computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date: $12,068,373,398.

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 February 22, 2008: 700,784,034

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 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2008.

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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	=	barrel
BBtu	=	billion British thermal units
Bcf	=	billion cubic feet
Bcfe	=	billion cubic feet of natural gas equivalents
LNG	=	liquefied natural gas
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
Mcfe	=	thousand cubic feet of natural gas equivalents
MDth	=	thousand dekatherms
MMBtu	=	million British thermal units
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
GWh	=	thousand megawatt hours
MW	=	megawatt
NGL	=	natural gas liquids
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 , the Company , or El Paso , we are describing El Paso Corporation and/o subsidiaries.

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PART I

ITEM 1. BUSINESS

Business and Strategy

We are an energy company, originally founded in 1928 in El Paso, Texas that primarily operates in the natural gas transmission and exploration and production sectors of the energy industry. Our purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner.

Natural Gas Transmission. We own or have interests in North America s largest interstate pipeline system with approximately 42,000 miles of pipe that connect North America s major natural gas producing basins to its major consuming markets. We also provide approximately 230 Bcf of storage capacity and have an LNG receiving terminal and related facilities in Elba Island, Georgia with 806 MMcf of daily base load sendout capacity. The size, connectivity and diversity of our U.S. pipeline system provides growth opportunities through infrastructure development or large scale expansion projects and gives us the capability to adapt to the dynamics of shifting supply and demand. Our focus is to enhance the value of our transmission business by successfully executing on our backlog of committed expansion projects in the United States and Mexico and developing new growth projects in our market and supply areas.

Exploration and Production. Our exploration and production business is currently focused on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we held an estimated 2.9 Tcfe of proved natural gas and oil reserves, not including our equity share in the proved reserves of an unconsolidated affiliate of 0.2 Tcfe. In this business, we are focused on growing our reserve base through disciplined capital allocation and portfolio management, cost control and marketing our natural gas and oil production at optimal prices while managing associated price risks.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Our business segments provide a variety of energy products and services and are managed separately as each segment requires different technology and marketing strategies. For a further discussion of our business segments, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through four separate, wholly owned pipeline systems, three majority-owned systems and three partially owned systems. These systems connect the nation s principal natural gas supply regions to the five largest consuming regions in the United States: the Gulf Coast, California, the northeast, the southwest and the southeast. We also have access to systems in Canada and assets in Mexico. Our Pipelines segment also includes our ownership of storage capacity through our transmission systems, two underground storage facilities and our LNG terminal and related facilities.

Each of our U.S. pipeline systems and storage facilities operate under Federal Energy Regulatory Commission (FERC) approved tariffs that establish rates, cost recovery mechanisms, and other terms and conditions of service to our customers. 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.

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Our strategy is to enhance the value of our transmission and storage business by:

- Successfully executing on our backlog of committed expansion projects;
- Developing new growth projects in our market and supply areas;
- Recontracting or contracting available or expiring capacity;
- Focusing on efficiency and synergies across our systems;
- Ensuring the safety of our pipeline systems and assets; and
- Providing outstanding customer service.

In November 2007, we formed El Paso Pipeline Partners, L.P., our master limited partnership (MLP). We contributed our Wyoming Interstate system and 10 percent general partner interests in each of Southern Natural Gas and Colorado Interstate Gas to the MLP. Our ownership interest in the MLP at December 31, 2007 consists of a two percent general partner interest and a 64.8 percent limited partner interest.

The tables below provide more information on our pipeline systems:

		As of December 31, 2007						
Transmission System	Supply and Market Region	Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2007	2006 (BBtu/d)	2005
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.	100	13,700	7,069	92	4,880	4,534	4,443
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian, Anadarko basins and via interconnects the Rocky Mountains to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650[2]	44	4,189	4,179	4,053
		100	400	400[4]		458	461	161

Mojave Pipeline (MPC)	Connects with the EPNG system near Cadiz, California, the EPNG and Transwestern systems at Topock, Arizona and to the Kern River Gas Transmission Company system in California. This system also extends to customers in the vicinity of Bakersfield, California.							
Cheyenne Plains Gas Pipeline (CPG) [3]	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	861		735	583	433

(1) Includes throughput transported on behalf of affiliates.

(2) Reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.

(3) Completed in 2005

(4) Reflects east to west flow capacity

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Transmission System	Supply and Market Region	As of December 31, 2007 Ownership Interest (Percent)	Miles of Pipeline[1]	Design Capacity[1] (MMcf/d)	Storage Capacity[1] (Bcf)	Average Throughput[1] 2007 (BBtu/d)	2006	2005
Southern Natural Gas (SNG)	Extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including, the metropolitan areas of Atlanta and Birmingham.	97	7,600	3,665	60	2,345	2,167	1,984
Colorado Interstate Gas (CIG)	Extends from production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnections with pipeline systems transporting gas to the midwest, the southwest, California and the Pacific northwest.	97	4,000	3,048	29	2,339	2,008	1,902
Wyoming Interstate (WIC)[2]	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	67	800	2,721		2,071	1,914	1,572
Florida Gas Transmission[3] (FGT)	Extends from South Texas to South Florida.	50	4,881	2,100		2,056	2,018	1,916

Samalayuca Pipeline and Gloria a Dios Compression Station[4]	Extends from U.S.-Mexico border to the state of Chihuahua, Mexico.	50	23	460	462	442	423
San Fernando Pipeline[4]	Extends from Pemex Compression Station 19 to the Pemex metering station in San Fernando, Mexico in the State of Tamaulipas.	50	71	1,000	951	951	951

(1) Includes throughput transported on behalf of affiliates and represents the systems totals and are not adjusted for our ownership interest.

(2) Includes the recently completed Kanda expansion project placed in service in January 2008.

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

(4) We have a 50 percent equity interest in Gasoductos de Chihuahua, which owns these systems.

In December 2007, we placed the LPG Burgos pipeline in service. This 117 mile pipeline, in which we own 50%, transports liquified petroleum gas and extends from Pemex s Burgos complex to the Monterrey market in the state of Nuevo Leoń, Mexico. The system has a design capacity of 30 million barrels/day and in 2007 we transported an average of 30 million barrels/day.

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As of December 31, 2007, we had the following FERC approved pipeline expansion projects on our systems. For a further discussion of other backlog expansion projects, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Project	Existing System	Capacity (MMcf/d)	Description	Anticipated Completion or In-Service Date
Essex Middlesex Project	TGP	80	To construct 7.8 miles of 24-inch pipeline connecting our Beverly-Salem line to the DOMAC line in Essex and Middlesex Counties, Massachusetts	November 2008
Medicine Bow Expansion	WIC	330	To construct a new 24,930 horsepower compression facility which increases capacity from the Powder River Basin in northeast Wyoming to the WIC mainline near the Cheyenne Hub	July 2008
Cheyenne Plains Expansion	CPG	70	To construct a new compression facility comprised of 10,310 horsepower at the Kirk Compressor Station in Yuma County, Colorado	July 2008
Cypress Phase II	SNG	114	To add 10,350 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	May 2008
Cypress Phase III	SNG	161	To add 20,700 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	January 2011
Southeast Supply Header (Phase I)	SNG	140	To construct 115 miles of pipeline to the western portion of our system and provide access through pipeline interconnects to several supply basins	June 2008

Intrastate Transmission Systems

CIG has a 50 percent interest in WYCO Development, L.L.C. (WYCO). WYCO owns a state regulated intrastate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to Public Service Company of Colorado s (PSCo) Fort St. Vrain electric generation plant. WYCO also owns a compressor station on our WIC system s Medicine Bow lateral in Wyoming and leases these pipeline and compression facilities to PSCo and WIC, respectively, under long-term leases. WYCO currently has two expansion projects underway, the High Plains pipeline and Totem storage expansion projects, expected to be completed in 2008 and 2009. CIG will lease these facilities and will be the operator of these projects.

Underground Natural Gas Storage Facilities

In addition to the storage along our pipeline systems, we own or have interests in the following natural gas storage facilities:

	As of December 31, 2007		
Storage Entity	**Ownership Interest (Percent)**	**Storage Capacity[1] (Bcf)**	**Location**
Bear Creek Storage	100	58	Louisiana
Young Gas Storage	48	6	Colorado

(1) Approximately 58 Bcf is contracted to affiliates. Amounts are not adjusted for our ownership interest.

LNG Facility

We own an LNG receiving terminal located on Elba Island, near Savannah, Georgia with a peak sendout capacity of 1.2 Bcf/d and a base load sendout capacity of 0.8 Bcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

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In September 2007, we received FERC approval to expand the Elba Island LNG receiving terminal and construct the Elba Express Pipeline. The expansion is anticipated to increase the peak sendout capacity of the terminal from 1.2 Bcf/d to 2.1 Bcf/d. The Elba Express Pipeline will consist of approximately 190 miles of pipeline with a total capacity of 1.2 Bcf/d, which will transport natural gas from the Elba Island LNG terminal to markets in the southeastern and eastern United States. In February 2008, we completed our acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, which is constructing a FERC approved liquefied natural gas terminal in Pascagoula, Mississippi that is expected to be placed in service in late 2011.

Markets and Competition

Our Pipelines segment provides 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 energy, wind, hydroelectric power and fuel oil.

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

Electric power generation is the fastest growing demand sector of the natural gas market. The growth of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power. This potential benefit is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity, increased natural gas prices and the use and availability of other fuel sources for power generation. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and electric transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm transportation contracts with natural gas pipelines.

Our existing contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or remarket expiring capacity is dependent on 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 requirements, we attempt to recontract or remarket our capacity at the 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. The table below shows our firm transportation contracts as of December 31, 2007 for our wholly and majority owned systems that expire by year over the next five years and thereafter.

The following table details information related to our pipeline systems, including the customers, contracts, markets served and the competition faced by each as of December 31, 2007. Firm customers reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities and 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. Interruptible customers are customers without reserved capacity that pay usage charges based on the volume of gas they request to transport, store, inject or withdraw.

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TGP

Customer Information	Contract Information	Competition
Approximately 440 firm and interruptible customers.	Approximately 500 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in its 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.
Major Customer: National Grid USA and subsidiaries		
(722 BBtu/d)	Expire in 2009-2027.	

EPNG

Approximately 140 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately four years.	EPNG faces competition in the west and southwest from other existing and proposed pipelines, from California storage facilities, and from alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customers: Southern California Gas Company		
(187 BBtu/d)	Expires in 2009.	
(246 BBtu/d)	Expires in 2010.	
(323 BBtu/d)	Expires in 2011.	
Southwest Gas Corporation		
(11 BBtu/d)	Expires in 2008.	
(603 BBtu/d)	Expire in 2011-2015.	

MPC

Approximately 20 firm and interruptible customers	Approximately five firm transportation contracts. Weighted average remaining contract term of	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar,

	approximately eight years.	coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customer:		
EPNG (312 BBtu/d)	Expires in 2015.	

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CPG

Customer Information	Contract Information	Competition
Approximately 50 firm and interruptible customers	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately eight years.	CPG competes directly with other interstate pipelines serving the mid-continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets.
Major Customers:		
Oneok Energy Services Company L.P. (195 BBtu/d)	Expires in 2015.	
Encana Marketing (USA) Inc. (170 BBtu/d)	Expires in 2015.	
Anadarko Petroleum Corporation (195 BBtu/d)	Expire in 2015-2016.	
Coral Energy Resources, L.P. (125 BBtu/d)	Expires in 2019.	

SNG

Approximately 280 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately six years.	SNG faces competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on SNG s system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. 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 their other customers. In addition, SNG competes with pipelines and gathering systems for connection to new supply sources.
Major Customers:		
Atlanta Gas Light Company (981 BBtu/d)	Expire in 2008-2015.	
Southern Company Services (418 BBtu/d)	Expire in 2010-2018.	
Alabama Gas Corporation (413 BBtu/d)	Expire in 2010-2013.	
SCANA Corporation		

(315 BBtu/d)	Expire in 2010-2019.

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CIG

Customer Information	Contract Information	Competition
Approximately 120 firm and interruptible customers	Approximately 180 firm transportation contracts. Weighted average remaining contract term of approximately five years.	CIG serves two major markets, an on- system market and an off- system market. Its on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an intrastate pipeline, an interstate pipeline, local production from the Denver-Julesburg basin, and long-haul shippers who elect to sell into this market rather than the off-system market. CIG s 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 this off-system market consists of interstate pipelines that are directly connected to its supply sources. CIG faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.
Major Customers:		
PSCo		
(187 BBtu/d)	Expires in 2008.	
(9 BBtu/d)	Expires in 2009.	
(1,106 BBtu/d)	Expire in 2012-2014.	
Williams Gas Marketing, Inc.		
(53 BBtu/d)	Expires in 2009.	
(113 BBtu/d)	Expires in 2010.	
(350 BBtu/d)	Expire in 2011-2013.	
Anadarko Petroleum Corporation		
(70 BBtu/d)	Expires in 2008.	
(12 BBtu/d)	Expires in 2009.	
(80 BBtu/d)	Expires in 2010.	
(128 BBtu/d)	Expire in 2011-2015.	

WIC[1]

Approximately 50 firm and interruptible customers	Approximately 50 firm transportation contracts. Weighted average remaining contract term of approximately ten years.	WIC competes with existing pipelines to provide transportation services from supply basins in northwest Colorado, eastern Utah and Wyoming to pipeline interconnects in northeast Colorado, and western Wyoming.

Major Customers:

Williams Gas Marketing, Inc.	
(25 BBtu/d)	Expires in 2008.
(84 BBtu/d)	Expires in 2010.
(744 BBtu/d)	Expire in 2013-2021.
Anadarko Petroleum Corporation	
(25 BBtu/d)	Expires in 2008.
(810 BBtu/d)	Expire in 2009-2022.

(1) Information included has been adjusted to reflect the completion of the Kanda expansion project placed in service in January 2008.

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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, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Each of our interstate pipeline systems and storage facilities operates under tariffs approved by the FERC that establish rates, cost recovery mechanisms, and terms and conditions for services to our customers. Generally, the FERC s authority extends to:

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

Our interstate pipeline systems are also subject to federal, state and local pipeline and LNG plant safety and environmental statutes and regulations of the U.S. Department of Transportation, the U.S. Department of Interior and the U.S. Coast Guard. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements, and we believe that our systems are in material compliance with the applicable regulations.

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Exploration and Production Segment

Our Exploration and Production segment s business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2007, we controlled over four million net leasehold acres and our proved natural gas and oil reserves at December 31, 2007, were approximately 2.9 Tcfe, which does not include 0.2 Tcfe related to our unconsolidated investment in Four Star Oil and Gas Company (Four Star). During 2007, daily equivalent natural gas production averaged approximately 792 MMcfe/d, not including 70 MMcfe/d from our equity investment in Four Star.

We completed the acquisition of Peoples Energy Production Company (Peoples) in September 2007 for $887 million. This acquisition upgraded our portfolio of assets across a number of our operating regions, primarily the Onshore and Texas Gulf Coast regions. We are also further upgrading our portfolio by selling selected non-core properties that no longer meet our strategic objectives. In January 2008, we entered into agreements to sell $517 million of certain non-core properties in our Onshore and Texas Gulf Coast regions with estimated proved reserves of 191 Bcfe at December 31, 2007. While we do not anticipate exiting any region, our divestitures will be weighted towards the Gulf of Mexico and south Texas areas. We have a balanced portfolio of development and exploration projects, including long-lived and shorter-lived properties divided into the following regions discussed below:

United States

Onshore. The Onshore region includes operations that are primarily focused on unconventional tight gas sands, coal bed methane and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this region. During 2007, we invested $543 million on capital projects, not including acquisitions, and production averaged 374 MMcfe/d. The principal operating areas are listed below:

			2007	
Area	**Description**	**Net Acres**	**Capital Investment (In millions)**	**Average Production (MMcfe/d)**
East Texas/North Louisiana (Arklatex)	Concentrated land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. The Peoples acquisition added to our existing asset in this area most notably in Logansport, Bald Prairie, Bethany, Minden and Bethany Longstreet fields. We also have land positions in the Mississippi area, primarily in Hub Field located on the southern edge of the Mississippi Salt Basin.	113,000	$ 260	136
Black Warrior Basin	Established shallow coal bed methane producing areas of northwestern Alabama. We have high average working interests in our operated properties in addition to an average 50 percent working interest covering approximately 46,000 net acres operated by Black Warrior Methane which produces from the Brookwood Field.	171,000	$ 51	62
Mid-Continent	Primarily in Oklahoma with a focus on development projects in the Arkoma Basin where we utilize horizontal drilling in the Hartshorne Coals area, West Verdon Field, an oil producing waterflood project and shallow natural	456,000	$ 40	30

	gas production in the Hugoton field.			
Rocky Mountains (Rockies)	Primarily in Wyoming and Utah with a focus in the Powder River and Uinta basins, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with non-operated coal bed methane fields. We operate the Altamont and Bluebell processing plants and related gathering systems in Utah. We also have a non-operated working interest primarily in the Stadium Unit in the Williston Basin of North Dakota, which is undergoing secondary recovery.	357,000	$ 79	71

Area	Description	Net Acres	2007 Capital Investment (In millions)	Average Production (MMcfe/d)
Raton Basin	Primarily focused on coal bed methane production in northern New Mexico and southern Colorado where we own the minerals and have a 100 percent working interest in the Vermejo Park Ranch. We also have working interests in land positions in the San Juan Basin primarily in the Fruitland Coal and Dakota formations and the tight gas formations in Pictured Cliffs and Mesaverde.	605,000	$ 113	75

Included in our Mid-Continent operating area are our interests in 127,000 net acres in West Virginia and 122,000 net acres in the Illinois Basin, primarily in the New Albany Shale area in southwestern Indiana. We are the operator of these properties and maintain a 50 percent working interest in this large emerging area which is still under evaluation. We have drilled 34 gross wells in this basin through the end of 2007.

Texas Gulf Coast. The Texas Gulf Coast region focuses on developing and exploring for tight gas sands in south Texas and the upper Gulf Coast of Texas. In this area, we have an inventory of over 10,000 square miles of three dimensional (3D) seismic data. During 2007, we acquired producing properties and undeveloped acreage in Zapata County, Texas for $254 million. During 2007, we also invested $327 million on capital projects and production averaged 213 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2007 Capital Investment (In millions)	Average Production (MMcfe/d)
Vicksburg/Frio Trends	Includes concentrated and contiguous assets, located in south Texas, including the Jeffress and Monte Christo fields primarily in Hidalgo County, in which we have an average 90 percent working interest. We also have assets in the Alvarado and Kelsey fields and in Starr and Brooks Counties with an average working interest of over 65 percent.	83,000	$ 128	132
Upper Gulf Coast Wilcox	Located onshore Texas Gulf Coast, including Renger, Dry Hollow, Brushy Creek and Speaks fields in Lavaca County and Graceland Field, located in Colorado, County.	37,000	$ 56	32
South Texas Wilcox	Includes positions in which we have working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. We also have working interests in the Laredo and Loma Novia fields in Webb and Duval counties.	79,000	$ 143	49

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Gulf of Mexico and south Louisiana. Our Gulf of Mexico and south Louisiana operations are generally characterized by relatively high initial production rates, resulting in near-term cash flows, and high decline rates. During 2007, we invested $309 million on drilling, workover and facilities projects and production averaged 191 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2007 Capital Investment (In millions)	2007 Average Production (MMcfe/d)
Gulf of Mexico	Primarily drilling interests in 148 Blocks south of the Louisiana, Texas and Alabama shorelines focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 300 feet).	543,000	$ 281	174
South Louisiana	Primarily in Vermilion Parish and associated bays and inland waters in southwestern Louisiana covered by the Catapult 3D seismic project. We have internally processed 2,800 square miles of contiguous 3D seismic data in this project.	21,000	$ 28	17

Unconsolidated Investment in Four Star. During the third quarter of 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and the Gulf of Mexico. During 2007, our proportionate share of Four Star s daily equivalent natural gas production averaged approximately 70 MMcfe/d and at December 31, 2007, proved natural gas and oil reserves, net to our interest, were 0.2 Tcfe.

International

Brazil. Our Brazilian operations cover approximately 361,000 net acres. During 2007, we invested $220 million on capital projects in Brazil. Our operations include interests in 13 concessions located in the Espirito Santo, Potiguar and Camamu Basins, including our 35 percent working interest in the Pescada-Arabaiana Fields in the Potiguar Basin. We currently own 100 percent of the BM-CAL-4 concession which includes the Pinauna project. During 2007, we completed drilling two successful exploratory wells that extended the southern limits of the Pinauna project. We are currently assessing development options and have a process underway to potentially market up to a 50 percent non-operating interest in this concession. In addition, we completed drilling and testing two exploratory wells with Petrobras in the ES-5 Block in the Espirito Basin. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. Our production in Brazil, primarily attributable to the Pescada-Arabaiana Fields, averaged approximately 14 MMcfe/d in 2007.

Egypt. Our Egyptian operations include a 20 percent non-operated working interest in approximately 13,000 net acres in the South Feiran concession located in the Gulf of Suez. We are currently in the seismic, exploratory drilling and evaluation phases of the project. Our total funding commitment to the South Feiran concession is $3 million. In 2007, we received formal government approval and signed the concession agreement for the South Mariut Block. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We paid $3 million for the concession and agreed to a $22 million firm working commitment over three years. We are currently performing seismic evaluations on the block and expect to drill our first exploratory well in late 2008.

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Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents our estimated proved reserves by region and classification as of December 31, 2007 based on an internal reserve report as well as our 2007 production by region. 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.

	Net Proved Reserves					2007
	Natural Gas (MMcf)	**Oil/Condensate (MBbls)**	**NGL (MBbls)**	**Total (MMcfe)**	**(Percent)**	**Production (MMcfe)**
Reserves and Production by Region						
United States						
Onshore	1,567,666	36,308	301	1,787,318	63%	136,701
Texas Gulf Coast	471,448	3,806	9,205	549,513	19%	77,633
Gulf of Mexico and south Louisiana	207,546	9,560	608	268,555	9%	69,671
Total United States	2,246,660	49,674	10,114	2,605,386	91%	284,005
Brazil	51,206	32,710		247,468	9%	5,237
Total	2,297,866	82,384	10,114	2,852,854	100%	289,242
Unconsolidated investment in Four Star	200,109	2,858	6,411	255,722	100%	25,470
Reserves by Classification						
United States						
Producing	1,419,621	26,578	6,679	1,619,159	62%	
Non-Producing	318,475	8,492	1,453	378,147	15%	
Undeveloped	508,564	14,604	1,982	608,080	23%	
Total proved	2,246,660	49,674	10,114	2,605,386	100%	
Brazil						
Producing	15,229	342		17,281	7%	
Non-Producing	3,414	338		5,444	2%	
Undeveloped	32,563	32,030		224,743	91%	
Total proved	51,206	32,710		247,468	100%	
Worldwide						
Producing	1,434,850	26,920	6,679	1,636,440	58%	

Non-Producing	321,889	8,830	1,453	383,591	13%
Undeveloped	541,127	46,634	1,982	832,823	29%
Total proved	2,297,866	82,384	10,114	2,852,854	100%
Unconsolidated investment in Four Star					
Producing	167,114	2,804	5,316	215,828	85%
Non-Producing	3,072		29	3,246	1%
Undeveloped	29,923	54	1,066	36,648	14%
Total Four Star	200,109	2,858	6,411	255,722	100%

Our consolidated reserves in the table above are 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 Company, L.P. (Ryder Scott), an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of 84 percent of our consolidated proved natural gas and oil reserves as of December 31, 2007. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising greater than 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 75 percent of the proved natural gas and oil reserves of Four Star, our unconsolidated affiliate. Our estimates of Four Star s proved natural gas and oil reserves are prepared by our internal reservoir engineers and do not reflect those prepared by the engineers of Four Star. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. Ryder Scott s reports are included as exhibits to this Annual Report on Form 10-K.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production costs, and projecting the timing of development expenditures, including many factors beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based, and on engineering and geological interpretations and judgment.

All estimates of proved reserves are determined according to the rules currently prescribed by the Securities and Exchange Commission (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.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as reserves are produced. 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. 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 tables detail (i) our interest in developed and undeveloped acreage at December 31, 2007, (ii) our interest in natural gas and oil wells at December 31, 2007 and (iii) our exploratory and development wells drilled during the years 2005 through 2007. 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)
Acreage						
United States						
Onshore	1,026,566	627,034	1,524,237	1,075,443	2,550,803	1,702,477
Texas Gulf Coast	173,282	119,025	114,842	80,396	288,124	199,421
Gulf of Mexico and south Louisiana	517,597	376,378	220,314	187,506	737,911	563,884
Total United States	1,717,445	1,122,437	1,859,393	1,343,345	3,576,838	2,465,782
Brazil	49,262	17,242	1,158,643	343,563	1,207,905	360,805
Egypt			1,247,064	1,195,272	1,247,064	1,195,272
Worldwide Total	1,766,707	1,139,679	4,265,100	2,882,180	6,031,807	4,021,859

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

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

In the United States, our net developed acreage is concentrated primarily in the Gulf of Mexico (33 percent), Texas (13 percent), Utah (11 percent), New Mexico (10 percent), Alabama (8 percent), Oklahoma (8 percent) and Louisiana (7 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (34 percent), the Gulf of Mexico (14 percent), Wyoming (10 percent), West Virginia (10 percent), Indiana (8 percent), Alabama (6 percent) and Texas (6 percent). Approximately 14 percent, 8 percent and 5 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 17 percent, 14 percent and 17 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008, 2009 and 2010. Approximately 30 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or through farm-out agreements with other operators.

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	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2007	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)(3)	Gross(1)	Net(2)
Productive Wells								
United States								
Onshore	4,901	3,627	658	495	5,559	4,122	74	61
Texas Gulf Coast	1,643	1,167			1,643	1,167	8	7
Gulf of Mexico and south Louisiana	193	127	56	31	249	158	2	1
Total	6,737	4,921	714	526	7,451	5,447	84	69
Brazil	4	1	6	2	10	3		
Worldwide Total	6,741	4,922	720	528	7,461	5,450	84	69

	Net Exploratory(2)(4)			Net Development(2)(4)		
	2007	2006	2005	2007	2006	2005
Wells Drilled						
United States						
Productive	214	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	226	112	88	239	321	283
Brazil						
Productive	3					
Dry						
Total	3					
Worldwide						
Productive	217	106	86	238	319	279
Dry	12	6	2	1	2	4
Total	229	112	88	239	321	283

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

interest.

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

(3) At December 31, 2007, we operated 4,905 of the 5,450 net productive wells.

(4) In 2007, there was a reduction in the number of non-operated development wells drilled in the Rockies and an increase in the number of exploration wells drilled in the Raton Basin.

The drilling performance 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.

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Net Production, Sales Prices, Transportation and Production Costs

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

	2007	2006	2005
Consolidated Volumes, Prices, and Costs per Unit:			
Net Production Volumes			
United States			
Natural gas (MMcf)	238,021	213,262	206,714
Oil, condensate and NGL (MBbls)	7,664	7,439	7,516
Total (MMcfe)	284,005	257,899	251,807
Brazil[(1)]			
Natural gas (MMcf)	4,295	7,140	15,578
Oil, condensate and NGL (MBbls)	157	247	620
Total (MMcfe)	5,237	8,619	19,300
Worldwide			
Natural gas (MMcf)	242,316	220,402	222,292
Oil, condensate and NGL (MBbls)	7,821	7,686	8,136
Total (MMcfe)	289,242	266,518	271,107
Total (MMcfe/d)	792	730	743
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Excluding hedges	$ 6.60	$ 6.77	$ 7.92
Including hedges	$ 7.36	$ 6.50	$ 6.69
Brazil			
Excluding hedges	$ 2.61	$ 2.61	$ 2.33
Including hedges	$ 2.61	$ 2.61	$ 2.33
Worldwide			
Excluding hedges	$ 6.53	$ 6.64	$ 7.53
Including hedges	$ 7.28	$ 6.38	$ 6.39
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Excluding hedges	$ 63.56	$ 55.95	$ 45.86
Including hedges	$ 63.56	$ 55.95	$ 45.86
Brazil			
Excluding hedges	$ 70.86	$ 64.02	$ 53.42
Including hedges	$ 41.27	$ 54.48	$ 42.42
Worldwide			
Excluding hedges	$ 63.71	$ 56.21	$ 46.43
Including hedges	$ 63.11	$ 55.90	$ 45.60
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.27	$ 0.24	$ 0.20
Oil, condensate and NGL ($/Bbl)	$ 0.83	$ 0.85	$ 0.69
Worldwide			
Natural gas ($/Mcf)	$ 0.27	$ 0.23	$ 0.18
Oil, condensate and NGL ($/Bbl)	$ 0.81	$ 0.82	$ 0.63

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	2007	2006	2005
Average Production Costs ($/Mcfe)			
United States			
Lease operating costs	$ 0.86	$ 0.97	$ 0.73
Production taxes	0.31	0.28	0.27
Total production costs	$ 1.17	$ 1.25	$ 1.00
Brazil			
Lease operating costs	$ 1.63	$ 0.28	$ 0.42
Production taxes	0.51	0.53	
Total production costs	$ 2.14	$ 0.81	$ 0.42
Worldwide			
Lease operating costs	$ 0.88	$ 0.95	$ 0.72
Production taxes	0.31	0.29	0.24
Total production costs	$ 1.19	$ 1.24	$ 0.96
Unconsolidated affiliate volumes (Four Star)[2]			
Natural gas (MMcf)	19,380	18,140	6,689
Oil, condensate and NGL (MBbls)	1,015	1,087	359
Total equivalent volumes			
MMcfe	25,470	24,663	8,844
MMcfe/d	70	68	24

(1) Production volumes in Brazil decreased due to a contractual reduction of our ownership interest in the Pescada-Arabaiana Fields in early 2006.

(2) Includes our proportionate share of volumes in Four Star which was acquired in 2005. In the third quarter of 2007, we increased our ownership interest

in Four Star from
43 percent to
49 percent.

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:

	2007	2006	2005
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 964	$ 2	$ 643
Unproved	262	34	143
Development Costs	735	738	503
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	19	23	7
Drilling	373	294	133
Asset Retirement Obligations	38	3	1
Total full cost pool expenditures	2,397	1,100	1,433
Non-full cost pool expenditures	13	8	22
Total costs incurred[1]	$ 2,410	$ 1,108	$ 1,455
Acquisition of unconsolidated investment in Four Star[2]	$ 27	$	$ 769
Brazil and Other International[1]			
Acquisition Costs:			
Proved	$	$ 2	$ 8
Unproved	5	1	1
Development Costs	26	40	6
Exploration Costs:			
Seismic acquisition and reprocessing	6	7	7
Drilling	193	46	8
Asset Retirement Obligations	7		
Total full cost pool expenditures	237	96	30
Non-full cost pool expenditures	1		
Total costs incurred	$ 238	$ 96	$ 30
Worldwide			
Acquisition Costs:			
Proved	$ 964	$ 4	$ 651
Unproved	267	35	144
Development Costs	761	778	509
Exploration Costs:			
Delay rentals	6	6	3
Seismic acquisition and reprocessing	25	30	14
Drilling	566	340	141
Asset Retirement Obligations	45	3	1

Total full cost pool expenditures	2,634	1,196	1,463
Non-full cost pool expenditures	14	8	22
Total costs incurred[1]	$ 2,648	$ 1,204	$ 1,485
Acquisition of unconsolidated investment in Four Star[2]	$ 27	$	$ 769

(1) Costs incurred for Egypt were $10 million and $4 million for the years ended December 31, 2007 and 2006.

(2) In 2005, amount includes deferred tax adjustments of $179 million related to the acquisition of full-cost pool properties and $217 million related to the acquisition of our unconsolidated investment in Four Star.

We spent approximately $200 million in 2007, $192 million in 2006 and $247 million in 2005 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

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Markets and Competition

We primarily sell our domestic natural gas and oil to third parties through our Marketing segment at spot market prices, subject to customary adjustments. We sell our NGL at market prices under monthly or long-term contracts, subject to customary adjustments. In Brazil, we sell the majority of our natural gas and oil to Petrobras, Brazil s state-owned energy company. We also enter into derivative contracts on our natural gas and oil production to stabilize our cash flows, reduce the risk and financial impact of downward commodity price movements and to protect the economic assumptions associated with our capital investment programs. As of December 31, 2007, our Exploration and Production segment had entered into derivative swap and option contracts on approximately 141 TBtu of our anticipated 2008 natural gas production, 16 TBtu of our total anticipated 2009-2012 natural gas production, basis swaps on 97 TBtu of our anticipated 2008 production and 15 TBtu of our total anticipated 2009-2012 natural gas production and fixed price swaps on 2,498 MBbls of our anticipated 2008 oil production. For a further discussion of these contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations. Our Marketing segment has also entered into additional production related derivative contracts as further described below.

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

Regulatory Environment. Our natural gas and oil exploration and production activities are regulated at the federal, state and local levels, in the United States, Brazil and Egypt. These regulations include, but are not limited to, those governing 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 exploration and production operations in Brazil and Egypt are subject to environmental regulations administered by those governments, which include political subdivisions in those countries. These domestic and international laws and regulations affect the construction and operation of facilities, water disposal rights, drilling operations, production or the delay or prevention of future offshore lease sales. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

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Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s natural gas and oil production and to manage the Company s overall price risk, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate various natural gas supply, transportation, power and other natural gas related contracts remaining from our legacy trading activities, which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2007, we managed the following types of contracts:

Production-Related Natural Gas and Oil Derivative Contracts. Includes options that provide price protection on our Exploration and Production segment s natural gas and oil production.

Natural Gas Transportation-Related Contracts. Includes contracts that provide transportation capacity primarily with our affiliates.

Legacy Natural Gas and Power Contracts. Includes a variety of natural gas derivative contracts and long-term supply obligations, including our Midland Cogeneration Venture (MCV) supply agreement and power contracts in the Pennsylvania-New Jersey-Maryland (PJM) region.

Production-Related Natural Gas and Oil Derivative Contracts

Our natural gas and oil contracts include options designed to provide price protection to El Paso from fluctuations in natural gas and oil prices. These contracts are in addition to contracts entered into by our Exploration and Production segment described in that segment. For a further discussion of the entirety of El Paso s production-related price risk management activities, refer to Item 7, Management s Discussion and Analysis of Financial Condition, Results of Operations and Liquidity and Capital Resources. As of December 31, 2007, our Marketing segment s contracts provided El Paso with price protection on the following quantities of future natural gas and oil production:

	2008	**2009**
Natural Gas (TBtu)		
Volumes with floor and ceiling prices		17
Oil (MBbls)		
Volumes with floor and ceiling prices	930	

Contracts Related to Legacy Trading Operations

Natural gas 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. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of working capital needed to use this capacity and the capacity required to meet our other long-term obligations. The following table details our transportation contracts as of December 31, 2007:

	Affiliated Pipelines[(1)]	**Other Pipelines**
Daily capacity (MMBtu/d)	521,000	63,000
Expiration	2009 to 2028	2012 to 2026
Receipt points	Various	Various
Delivery points	Various	Various

(1) Primarily consists of contracts with TGP and EPNG.

Other natural gas contracts. As of December 31, 2007, we had eight significant physical natural gas contracts with power plants associated with our legacy trading activities, including MCV. We sold our equity investment in the MCV power facility in 2006. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2008 to 2028, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d.

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Power contracts. As of December 31, 2007, we had four derivative contracts that require us to swap locational differences in power prices between four power plants in the PJM eastern region with the PJM west hub. In total, these contracts require us annually to swap locational differences in power prices on approximately 4,000 GWh of power through 2008; 3,700 GWh from 2009 to 2012; 2,400 GWh for 2013 and 1,700 GWh from 2014 to 2016. Additionally, these contracts require us to provide installed capacity of approximately 71 GWh per year in the PJM power pool through 2016. While we have basis and capacity risk associated with the contracts, we do not have commodity risk associated with these contracts due to positions we put in place prior to 2007.

Markets, Competition and Regulatory Environment

Our Marketing 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 major oil and natural gas producers and their affiliates, large domestic and foreign utility companies, large local distribution companies and their affiliates, other interstate and intrastate pipelines and their affiliates, and independent energy marketers and financial institutions. Our marketing activities are subject to the regulations of among others, the FERC and the Commodity Futures Trading Commission.

Power Segment

As of December 31, 2007, our Power segment primarily included the ownership and operation of our remaining investments in international power generation facilities listed below. These facilities primarily sell power under long-term power purchase agreements with power transmission and distribution companies owned by local governments. As a result, we are subject to certain political risks related to these facilities. We continue to pursue the sale of our remaining power investments.

Project	Area	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Brazil						
Manaus[1]	Brazil	100	238	Manaus Energia	2008	Oil
Porto Velho[2]	Brazil	50	404	Eletronorte	2010, 2023	Oil
Rio Negro[1]	Brazil	100	158	Manaus Energia	2008	Oil
Asia & Central America						
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna Power Co.	Bangladesh	74	113	BPDB	2013	Heavy Fuel Oil
Tipitapa[3]	Nicaragua	60	51	Union Fenosa	2014	Heavy Fuel Oil

(1) Ownership of these plants transferred to the power purchaser in January 2008.

(2) In the third quarter of 2007, we received an

offer from our partners to purchase this investment. For further discussion, see Item 8, Financial Statements, Note 17.

(3) In December 2007, we signed an agreement to sell this facility which is expected to close in the first half of 2008.

In addition to the international power plants above, we also have investments in two operating pipelines in South America with a total design capacity and average 2007 throughput of 1,197 MMcf/d and 1,162 BBtu/d, unadjusted for our ownership interest.

Regulatory Environment. Our remaining international power generation activities are regulated by governmental agencies in the countries in which these projects are located. Many of these countries have developed or are developing new regulatory and legal structures for private and foreign-owned businesses. These regulatory and legal structures are subject to change over time.

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Environmental

A description of our environmental activities is included in Part II, Item 8 Financial Statements and Supplementary Data, Note 12.

Employees

As of February 22, 2008, we had approximately 4,992 full-time employees, of which 204 employees are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of February [26], 2008, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso	2003	48
D. Mark Leland	Executive Vice President and Chief Financial Officer of El Paso	2005	46
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	51
Brent Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	46
Susan B. Ortenstone	Senior Vice President (Human Resources and Administration) of El Paso	2003	51
James C. Yardley	Executive Vice President, Pipeline Group	2005	56
James J. Cleary	President of Western Pipeline Group	2005	53
Daniel B. Martin	Senior Vice President of Pipeline Operations	2005	51

Douglas L. Foshee has been President, Chief Executive Officer and a director of El Paso since September 2003. He became Executive Vice President and Chief Operating Officer of Halliburton Company in 2003, having joined that company in 2001 as Executive Vice President and Chief Financial Officer. Several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, commenced prepackaged Chapter 11 proceedings to discharge current and future asbestos and silica personal injury claims in December 2003 and an order confirming a plan of reorganization became final effective December 31, 2004. Under the plan of reorganization, all current and future asbestos and silica personal injury claims were channeled into trusts established for the benefit of asbestos and silica claimants. Prior to assuming his position at Halliburton, Mr. Foshee was President, Chief Executive Officer and Chairman of the Board of Nuevo Energy Company from 1997 to 2001. From 1993 to 1997, Mr. Foshee served Torch Energy Advisors Inc. in various capacities, including Chief Executive Officer and Chief Operating Officer. Mr. Foshee serves on the Federal Reserve Bank of Dallas, Houston Branch as a director. Mr. Foshee serves on the Board of Trustees of Rice University, where he chairs the Building and Grounds Committee in addition to serving as a member of the Council of Overseers for the Jesse H. Jones Graduate School of Management at Rice University. He is a member of the Greater Houston Partnership Board and Executive Committee and serves as Chair of the Environment Advisory Committee. In addition, Mr. Foshee serves on the Boards of Central Houston, Inc., Children s Museum of Houston, Goodwill Industries, Small Steps Nurturing Center and the Texas Business Hall of Fame Foundation. Mr. Foshee serves on the board of directors of El Paso Pipeline GP Company, L.L.C., the general partner of El Paso Pipeline Partners, L.P.

D. Mark Leland has been Executive Vice President and Chief Financial Officer of El Paso since August 2005. Mr. Leland served as Executive Vice President of El Paso Exploration & Production Company (formerly known as El Paso Production Holding Company) from January 2004 to August 2005, and as Chief Financial Officer and a Director from April 2004 to August 2005. He served in various capacities for GulfTerra Energy Partners, L.P. and its general partner, including as Senior Vice President and Chief Operating Officer from January 2003 to December 2003, as Senior Vice President and Controller from July 2000 to January 2003, and as Vice President from August 1998 to July 2000. Mr. Leland has also worked in various capacities for El Paso Field Services and El Paso Natural Gas Company since 1986. Mr. Leland serves on the board of directors of El Paso Pipeline GP Company, L.L.C.

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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 worked in various capacities in the legal department of Tenneco Energy and El Paso since 1983. Mr. Baker serves as Executive Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C.

Brent J. Smolik has been Executive Vice President of El Paso and President of El Paso Exploration & Production Company since November 2006. Mr. Smolik was President of ConocoPhillips Canada from April 2006 to October 2006. Prior to the Burlington Resources merger with ConocoPhillips, he was President of Burlington Resources Canada from September 2004 to March 2006. From 1990 to 2004, Mr. Smolik worked in various engineering management and executive capacities for Burlington Resources Inc.

Susan B. Ortenstone has been Senior Vice President of El Paso since October 2003. Ms. Ortenstone was Chief Executive Officer for Epic Energy Pty Ltd. from January 2001 to June 2003. She served as Vice President of El Paso Gas Services Company and President of El Paso Energy Communications from December 1997 to December 2000. Prior to that time Ms. Ortenstone worked in various strategy, marketing, business development, engineering and operations capacities since 1979. Ms. Ortenstone serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C.

James C. Yardley has been Executive Vice President of El Paso with responsibility for the regulated pipeline business unit since August 2006. He has also served as President of Southern Natural Gas Company since May 1998 and President and Chairman of the Board of Tennessee Gas Pipeline Company since August 2006. Mr. Yardley has also been Chairman of the Board of El Paso Natural Gas Company since August 2006. He has been a member of the Management Committees of both Colorado Interstate Gas Company and Southern Natural Gas Company since their conversion to general partnerships in November 2007. Mr. Yardley served as Vice President, Marketing and Business Development for Southern Natural Gas Company from April 1994 to April 1998. Prior to that time, he worked in various capacities with Southern Natural Gas and Sonat Inc. beginning in 1978. Mr. Yardley serves as Director, President and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C.

James J. Cleary has been President of El Paso Natural Gas Company and Colorado Interstate Gas Company since January 2004. He also served as Chairman of the Board of El Paso Natural Gas Company and Colorado Interstate Gas Company from May 2005 to August 2006. From January 2001 to December 2003, he served as President of ANR Pipeline Company. Prior to that time, Mr. Cleary served as Executive Vice President of Southern Natural Gas Company from May 1998 to January 2001. He also worked for Southern Natural Gas Company and its affiliates in various capacities beginning in 1979. Mr. Cleary serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C

Daniel B. Martin has been Director of Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company and Tennessee Gas Pipeline Company since May 2005. He was Director of ANR prior to its sale in February 2007. He has been Senior Vice President of El Paso Natural Gas Company since February 2000, Senior Vice President of Southern Natural Gas Company and Tennessee Gas Pipeline Company since June 2000 and Senior Vice President Colorado Interstate Gas Company since January 2001. He was Senior Vice President of ANR Pipeline prior to its sale in February 2007. Prior to 2001, Mr. Martin worked in various capacities with Tennessee Gas Pipeline Company since 1978. Mr. Martin serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C.

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.

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ITEM 1A. RISK FACTORS

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

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

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

Risks Related to Our Business

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires, adverse weather conditions (such as hurricanes and flooding), terrorist activity or acts of aggression, and other hazards. Each of these risks could result in damage to or destruction of our facilities or damages or injuries to persons and property causing us to suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our insurance coverages have material deductibles and self-insurance levels, as well as limits on our maximum recovery, and do not cover all risks. As a result, our results of operations, cash flows or financial condition could be adversely affected if a significant event occurs that is not fully covered by insurance.

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

Most of the natural gas we transport and store is owned by third parties. The results of our transportation and storage operations are impacted by the volumes of natural gas we transport or store and the prices we are able to charge for doing so. The volume of natural gas we are able to transport and store depends on the actions of those third parties and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, or to remarket unsubscribed capacity on our pipeline systems:

- service area competition;
- expiration or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- weather conditions that impact throughput and storage levels;
- price competition;
- drilling activity and decreased availability of conventional gas supply sources and the availability and timing of other natural gas supply sources, such as LNG;

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- continued development of additional sources of gas supply that can be accessed;
- decreased natural gas demand due to various factors, including increases in prices and the availability or increased demand of alternative energy sources such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil;
- availability and cost of capital to fund ongoing maintenance and growth projects;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions including prolonged recessionary periods that might negatively impact natural gas demand and the capital markets;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands; and
- unfavorable movements in natural gas prices in certain supply and demand areas.

Certain of our systems transportation services are subject to long-term, fixed-price negotiated rate contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts.

It is possible that costs to perform services under negotiated rate contracts will exceed the negotiated rates. Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a negotiated rate which may be above or below the FERC regulated recourse rate for that service, and that contract must be filed and accepted by FERC. These negotiated rate contracts are not generally subject to adjustment for increased costs which could be produced by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between recourse rates (if higher) and negotiated rates, under current FERC policy is generally not recoverable from other shippers.

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

Substantially all of our pipeline subsidiaries revenues are generated under contracts which expire periodically and must be renegotiated, extended or replaced. If we are unable to extend or replace these contracts when they expire or renegotiate contract terms as favorable as the existing contracts, we could suffer a material reduction in our revenues, earnings and cash flows. In particular, our ability to extend and replace contracts could be adversely affected by factors we cannot control, including:

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

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

Revenues generated by our transportation, storage and LNG contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and LNG. Increased prices could result in a reduction of the volumes transported by our customers, including power companies that may not dispatch natural gas-fired power plants if natural gas prices increase. Increased prices could also result in industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies loss of customer base. The success of our transmission, storage and LNG operations is subject to continued development of additional gas supplies to offset the natural decline from existing wells connected to our systems, which requires the development of additional oil and natural gas reserves, obtaining additional supplies from interconnecting pipelines, and the development of LNG facilities on or near our systems. A decline in energy prices could cause a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, storage and processing through our systems. Pricing volatility may impact the value of under or over recoveries of retained natural gas, imbalances and system encroachments. If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted on a short-term basis, as well as with respect to our long-term recontracting activities. Furthermore, fluctuations in pricing between supply sources and market areas could negatively impact our transportation revenues. Fluctuations in energy prices are caused by a number of factors, including:

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

The expansion of our pipeline systems by constructing new facilities subjects us to construction and other risks that may adversely affect the financial results of our pipeline businesses.

We may expand the capacity of our existing pipeline, storage or LNG facilities by constructing additional facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- our ability to obtain necessary approvals and permits by the FERC and other regulatory agencies on a timely basis and on terms that are acceptable to us;
- the ability to obtain continued access to sufficient capital to fund expansion projects;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes, regulations, and orders, including environmental requirements that prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire rights-of-way or land rights on a timely basis or on terms that are acceptable to us;
- our ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from inflation or increased costs of equipment, materials, labor, contractor productivity or other factors beyond our control, that we may not be able to recover from our customers which may be material;
- the lack of future growth in natural gas supply; and
- the lack of transportation, storage or throughput commitments.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve our expected investment return, which could adversely affect our results of operations, cash flows or financial position.

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

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

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

Further, because the majority of our proved reserves at December 31, 2007 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices than we are to changes in oil prices. Declines in natural gas and oil prices would not only reduce revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could adversely affect the financial results of our exploration and production business. A decline in natural gas and oil prices could result in a downward revision of our reserves and a full cost ceiling test write-down of the carrying value of our natural gas and oil properties, which could be substantial, and would negatively impact our net income and stockholders equity.

The success of our exploration and production business is dependent, in part, on the following factors.

The performance of our exploration and production business is dependent upon a number of factors that we cannot control, including:

- the results of future drilling activity;
- the availability and increases in future costs of rigs, equipment and labor to support drilling activity and production operations;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;

our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive conditions from other companies;

our ability to successfully integrate acquisitions;

adverse changes in future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;

increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;

governmental action affecting the profitability of our exploration and production activities, such as increased royalty rates payable on oil and gas leases, the imposition of additional taxes on such activities or the modification or withdrawal of tax incentives in favor of exploration and development activity;

our lack of control over jointly owned properties and properties operated by others;

declines in production volumes, including those from the Gulf of Mexico; and

continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

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

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks. Additionally, our 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 of drilling rights by governmental authorities based on environmental and other considerations. Each of these risks could result in damage to property, injuries to people or the shut in of existing production as damaged energy infrastructure is repaired or replaced.

We maintain insurance coverage to reduce exposure to potential losses resulting from these operating hazards. The nature of the risks is such that some liabilities could exceed our insurance policy limits, or, as in the case of environmental fines and penalties, cannot be insured which could adversely affect our future results of operations, cash flows or financial condition.

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

Estimating our reserves, production and future net cash flow is inherently imprecise.

Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. It also requires making estimates based upon economic factors, such as natural gas and oil prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. We also use a ten percent discount factor for estimating the value of our future net cash flows from reserves and a one-day spot price (typically the last day of the year), each as prescribed by the SEC. This discount factor may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our exploration and production business or the natural gas and oil industry, in general, are subject. Additionally, this one day spot price will not generally represent the market prices for natural gas and oil over time. Any significant variations from the interpretations or assumptions used in our estimates or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially.

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

A portion of our estimated proved reserves are undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change.

The success of our exploration and production business depends upon our ability to replace reserves that we produce.

Unless we successfully replace the reserves that we produce, our reserves will decline which will eventually result in a decrease in natural gas and oil production and lower revenues and cash flows from operations. We historically have replaced reserves through both drilling and acquisitions. The business of exploring for, developing or acquiring reserves requires substantial capital expenditures. Our operations require continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics. If we do not continue to make significant capital expenditures, if our capital resources become limited, or if our exploration, development and acquisition activities are unsuccessful, we may not be able to replace the reserves that we produce, which would negatively affect our future revenues, cash flows and results of operations.

We face competition from third parties to acquire and develop natural gas and oil reserves.

The natural gas and oil business is highly competitive in the search for and acquisition of reserves. Our competitors include the major and independent natural gas and oil companies, individual producers, gas marketers and major pipeline companies some of which have financial and other resources that are substantially greater than those available to us, as well as participants in other industries supplying energy and fuel to industrial, commercial and individual consumers. In order to expand our leased land positions in intensively competitive and desirable areas, we must identify and precisely locate prospective geologic structures, identify and review any potential risks and uncertainties in these areas, and drill and successfully complete wells in a timely manner. Our future success and profitability in the production business may be negatively impacted if we are unable to identify these risks or uncertainties and find or acquire additional reserves at costs that allow us to remain competitive.

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

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

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

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States, including power, pipeline and exploration and production projects in Brazil, exploration and production projects in Egypt and pipeline projects in Mexico, are subject to the risks inherent in foreign operations. As a general rule, we have elected not to carry political risk insurance against these sorts of risks including:

- loss of revenue, property and equipment as a result of hazards such as wars or insurrection;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems;
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties, nationalization, and expropriation; and
- protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations.

Retained liabilities associated with businesses that we have sold could exceed our estimates and we could experience difficulties in managing these liabilities.

We have sold a significant number of assets and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold, including breaches of warranties, environmental expenditures, asset maintenance, tax, litigation, personal injury claims and other representations that we have provided. Although we believe that we have established appropriate reserves for these liabilities, we could be required to accrue additional amounts in the future and these amounts could be material. We have experienced substantial reductions and turnover in the workforce that previously supported the ownership and operation of such assets which could result in difficulties in managing these businesses, including a reduction in historical knowledge of the assets and businesses and in managing the liabilities retained after closing or defending any associated litigation.

Our business requires the retention and recruitment of a skilled workforce and the loss of employees could result in the failure to implement our business plans.

Our pipeline and exploration and production businesses require the retention and recruitment of a skilled workforce. If we are unable to retain and recruit employees such as engineers and other technical personnel, our business could be negatively impacted.

Risks Related to Legal and Regulatory Matters

The outcome of pending governmental investigations could be materially adverse to us.

We are subject to various governmental investigations by one or more of the following governmental agencies: the SEC, FERC and the U.S. Department of Transportation Office of Pipeline Safety. Although we are cooperating with the governmental agency or agencies in these investigations, the outcome of each of these investigations and the costs to the Company of responding and participating in these investigations is uncertain. The ultimate costs and sanctions, if any, that may be imposed upon us could have a material adverse effect on our business, financial condition or results of operation.

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

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, the U.S. Department of Interior, and various state and local regulatory agencies whose actions have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services and sets authorized rates of return. The FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC had been using a proxy group of companies that included local distribution companies that are not faced with as much competition or risk as interstate pipelines. The inclusion of these lower risk companies could have created downward pressure on tariff rates when subjected to review by the FERC in future rate proceedings. Recently, the U.S. Court of Appeals for the DC Circuit issued a decision that would require the FERC, if it utilizes lower risk companies in the proxy group, to make upward adjustments to the return on equity to compensate for their lower level of risk. Pursuant to the FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. A successful complaint or protest against our pipelines rates could have an adverse impact on our revenues. In addition, in July 2007, the FERC issued a proposed policy statement addressing the issue of the proxy groups it will use to decide the return on equity of natural gas pipelines. The proposed policy statement describes the FERC s intention to allow the use of master limited partnerships in proxy groups, which we and other pipelines have advocated. However, the FERC also proposed certain restrictions that would reduce the overall benefit that pipelines would receive by use of master limited partnerships in the proxy group. Through our trade association, we have filed comments on the policy and participated in a public conference on this subject.

Additionally, we formed El Paso Pipeline Partners, L.P., a master limited partnership, in 2007. The FERC currently allows publicly traded partnerships to include in their cost-of-service an income tax allowance. Any changes to FERC s treatment of income tax allowances in cost of service and to potential adjustment in a future rate case of our pipelines respective equity rates of return that underlie their recourse rates may cause their recourse rates to be set at a level that is different, and in some instances lower than the level otherwise in effect, could negatively impact our investment in El Paso Pipeline Partners, L.P.

Also, increased regulatory requirements relating to the integrity of our pipelines requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures. Further, state agencies that regulate our pipelines local distribution company customers could impose requirements that could impact demand for our pipelines services.

Environmental compliance and remediation costs and the costs of environmental liabilities could exceed our estimates.

Our operations are subject to various environmental laws and regulations regarding compliance and remediation obligations. Compliance obligations can result in significant costs to install and maintain pollution controls, fines and penalties resulting from any failure to comply and potential limitations on our operations. Remediation obligations can result in significant costs associated with the investigation or clean up of contaminated properties (some of which have been designated as Superfund sites by the Environmental Protection Agency (EPA) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)), as well as damage claims arising out of the contamination of properties or impact on natural resources. Although we believe we have established appropriate reserves for our environmental liabilities, it is not possible for us to estimate the exact amount and timing of all future expenditures related to environmental matters and we could be required to set aside additional amounts which could significantly impact our future consolidated results of operations, cash flows or financial position. See Part I, Item 3, Legal Proceedings and Part II, Item 8, Financial Statements and Supplementary Data, Note 12.

In estimating our environmental liabilities, we face uncertainties that include:

- estimating pollution control and clean up costs, including sites where preliminary site investigation or assessments have been completed;
- discovering new sites or additional information at existing sites;
- quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- evaluating and understanding environmental laws and regulations, including their interpretation and enforcement; and
- changing environmental laws and regulations that may increase our costs.

Currently, various legislative and regulatory measures to address greenhouse gas (GHG) emissions, including carbon dioxide and methane, are in various phases of discussion or implementation. These include the Kyoto Protocol which has been ratified by some of the international countries in which we have operations such as Mexico, Brazil, and Egypt. In the United States, various federal legislative proposals have been made over the last several years. It is difficult to predict the timing of enactment of any federal legislation, as well as the ultimate legislation that will be enacted. However, components of the legislation that have been proposed in the past could negatively impact our operations and financial results, including whether any of our facilities are designated as the point of regulation for GHG emissions, whether the federal legislation will expressly preempt the potentially conflicting state GHG legislation and how inter-fuel issues will be handled, including how allowances are granted and whether caps will be imposed on GHG charges.

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Legislation and regulation are also in various stages of proposal, enactment, and implementation in many of the states in which we operate. This includes various initiatives of individual states and coalition of states in the northeastern portion of the United States that are members of the Regional Greenhouse Gas Initiative and seven western states that are members of the Western Climate Initiative.

Additionally, various governmental entities and environmental groups have filed lawsuits seeking to force the federal government to regulate GHG emissions and individual companies to reduce the GHG emissions from their operations. These and other suits may also result in decisions by federal agencies and state courts and other agencies that impact our operations and ability to obtain certifications and permits to construct future projects.

These legislative, regulatory, and judicial actions could result in changes to our operations and to the consumption and demand for natural gas and oil. Changes to our operations could include increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, (iii) construct new facilities, (iv) acquire allowances to authorize our GHG emissions, (v) pay any taxes related to our GHG emissions and (vi) administer and manage a GHG emissions program.

While we may be able to include some or all of any costs in our rates charged by our pipelines and in the prices at which we sell natural gas and oil, such recovery of costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

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

We are involved in various lawsuits in which we or our subsidiaries have been sued (see Part II, Item 8, Financial Statements and Supplementary Data, Note 12). We also have other contingent liabilities and exposures. Although we believe we have established appropriate reserves for these liabilities, we could be required to set aside additional amounts in the future and these amounts could be material.

Risks Related to Our Liquidity

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

We have significant debt, debt service and debt maturity obligations. The ratings assigned to El Paso s senior unsecured indebtedness are below investment grade, currently rated Ba3 with a positive outlook by Moody s Investor Service (Moody s) and BB- with a positive outlook by Standard & Poor s. These ratings have increased our cost of capital and our operating costs, particularly in our marketing operations, and could impede our access to capital markets. Although we must retain greater liquidity levels to operate our business than if we had investment grade credit ratings, the simplification of our capital structure and business has reduced the amount of liquidity we maintain in the ordinary course of business. If there is significant volatility in energy commodity prices or interest rates, then these lower liquidity levels might not be adequate. In such an event, if our ability to generate or access capital becomes significantly restrained, then our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 11, for a further discussion of our debt.

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

Our debt and other financing obligations contain restrictive covenants, which become more restrictive over time, and contain cross default provisions. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we might not be able to repay such debt and other financing obligations.

Additionally, some of our credit agreements are collateralized by our equity interests in EPNG and TGP as well as certain natural gas and oil reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to foreclose on these collateral interests.

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Adverse changes in general domestic economic conditions could adversely affect our operating results, financial condition, or liquidity.

We are subject to the risks arising from adverse changes in general domestic economic conditions including recession or economic slowdown. Recently, the direction and relative strength of the U.S. economy has been increasingly uncertain due to softness in the housing markets, rising oil prices, and difficulties in the financial services sector. If economic growth in the United States is slowed, demand growth from consumers for natural gas and oil produced and transported by us on our natural gas transportation systems may decrease which could impact our planned growth capital. Additionally, our access to capital could be impeded. Any of these events, which are beyond our control, could negatively impact our business, results of operations, financial condition, and liquidity.

We are subject to financing and interest rate risks.

Our future success, financial condition and liquidity could be adversely affected based on our ability to access capital markets and obtain financing at cost effective rates. This is dependent on a number of factors, many of which we cannot control, including changes in:

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

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Part I, 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 12, and are incorporated herein by reference.

Fort Morgan Storage Field. CIG owns and operates an underground natural gas storage field in the vicinity of Fort Morgan, Colorado. In October 2006, the production casing in one of the field s injection and withdrawal wells failed resulting in the emergence of natural gas from the storage reservoir at the ground surface. In June 2007, CIG received a proposed Administrative Order of Consent (AOC) from the Colorado Oil and Gas Conservation Commission (Commission). In January 2008, the Commission approved the AOC with a settlement of all alleged violations with a penalty of $374,000.

Rawlins Plant Notice of Probable Violation. CIG owns and operates the Rawlins Gas Plant and Compressor Station which produces butane, propane, and natural gas liquids. Recently, CIG discovered that emissions from the loading process were emitted into the atmosphere and reported the discovery to the Wyoming Department of Environmental Quality (Department) which issued a Notice of Violation. CIG has reached an agreement with the Department to pay a total of $83,000 and to conduct a supplemental environmental program to install additional equipment which will reduce future emissions.

Natural Buttes. On May 19, 2004, the Federal Environmental Protection Agency (EPA) issued a Compliance Order (Order) to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. On July 7, 2004, the EPA issued a confidential Pre-filing Settlement Offer which contained a proposed fine of $350,000. In September 2005 the matter was referred to the U.S Department of Justice (DOJ). We have entered into a tolling agreement with the United States and have concluded settlement discussions in principle with the DOJ and the EPA, setting a penalty of $470,000, which includes $50,000 in incremental costs for a Supplemental Environmental Project. We have established a reserve for this penalty amount, and we anticipate a documented settlement in the first half of 2008.

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

None.

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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 February 22, 2008, we had 33,757 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

Quarterly Stock Prices. 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 per share we declared in each quarter:

	High	Low	Dividends
2007			
Fourth Quarter	$18.37	$15.29	$0.04
Third Quarter	18.56	15.00	0.04
Second Quarter	17.43	14.41	0.04
First Quarter	15.66	13.71	0.04
2006			
Fourth Quarter	$15.84	$12.92	$0.04
Third Quarter	16.39	12.82	0.04
Second Quarter	16.00	11.85	0.04
First Quarter	13.95	11.80	0.04

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2002 as invested in (i) El Paso s common stock, (ii) the Standard & Poor s 500 Stock Index, (iii) the Standard & Poor s 500 Oil & Gas Storage & Transportation Index and (iv) our peer group identified below. The Peer Group we used for this comparison is the same group we use to compare total shareholder return relative to our performance for compensation purposes. Our peer group for 2007 included the following companies: Anadarko Petroleum Corp., Apache Corp., CenterPoint Energy Inc., Devon Energy Corp., Dominion Resources, Inc., Enbridge, Inc., Equitable Resources, Inc., NiSource, Inc., ONEOK, Inc., PG&E Corp., PPL Corp., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., Transcanada Corp. and Williams Companies, Inc. Our peer group for 2006 included the companies listed above as well as Western Gas Resources, Inc. and Kinder Morgan, Inc., but did not include Spectra Energy Corp.

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COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS

	12/02	12/03	12/04	12/05	12/06	12/07
El Paso Corporation	$100	$120.27	$155.64	$184.60	$234.61	$267.31
S&P 500 Stock Index	$100	$128.68	$142.69	$149.70	$173.34	$182.86
S&P 500 Oil & Gas Storage & Transportation Index[1]	$100	$163.09	$228.19	$301.43	$358.54	$409.59
New Peer Group	$100	$137.32	$172.32	$225.16	$254.39	$319.86
Old Peer Group	$100	$137.51	$172.76	$226.38	$256.51	$328.44

(1) The S&P 500 Oil & Gas Storage & Transportation Index was created as of May 1, 2005 and thus, historical values for this index were not available. Accordingly, we provided this comparison against a custom index which includes the companies in the Standard & Poor s 500 Oil & Gas Storage & Transportation Index, including El Paso.

(2) The annual values of each investment are based on the share price appreciation and assume cash dividend reinvestment. The calculations exclude any applicable

brokerage commissions and taxes. Cumulative total stockholder returns from each investment can be calculated from the annual values given above.

Dividends Declared. On February 7, 2008, we declared a quarterly dividend of $0.04 per share of our common stock, payable on April 1, 2008, to shareholders of record as of March 7, 2008. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

Other. The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set apart for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restrictions on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If our fixed charge ratio were to exceed the permitted maximum level, our ability to pay additional dividends would be restricted.

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 Computershare Trust Company, N.A., our stock transfer agent at 1-877-453-1503.

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ITEM 6: SELECTED FINANCIAL DATA

The following selected historical financial data as of and for the years ended December 31, 2004 to 2007 is derived from our audited consolidated financial statements for El Paso and its subsidiaries and is not necessarily indicative of results to be expected in the future. The amounts as of and for the year ended December 31, 2003, are derived from unaudited consolidated financial statements. Such amounts were adjusted to reflect the reclassification of ANR, our Michigan storage assets and our 50% interest in Great Lakes Gas Transmission as discontinued operations. The selected financial data should be read together with Part II, 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.

	As of or for the Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,648	$ 4,281	$ 3,359	$ 4,783	$ 5,596
Income (loss) from continuing operations	$ 436	$ 531	$ (506)	$ (1,032)	$ (795)
Net income (loss) available to common stockholders	$ 1,073	$ 438	$ (633)	$ (947)	$ (1,883)
Basic earnings (loss) per common share from continuing operations	$ 0.57	$ 0.73	$ (0.82)	$ (1.61)	$ (1.33)
Diluted earnings (loss) per common share from continuing operations	$ 0.57	$ 0.72	$ (0.82)	$ (1.61)	$ (1.33)
Cash dividends declared per common share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Basic average common shares outstanding	696	678	646	639	597
Diluted average common shares outstanding	699	739	646	639	597
Financial Position Data:					
Total assets	$ 24,579	$ 27,261	$ 31,840	$ 31,398	$ 36,968
Long-term financing obligations, less current maturities	12,483	13,329	16,282	17,506	19,193
Minority Interest	565	31	31	367	447
Stockholders equity	5,280	4,186	3,389	3,438	4,346

Factors Affecting Trends. Prior to 2006, our financial position and operating results were substantially affected by the restructuring and realignment of our business around our core pipeline and exploration and production operations. Accordingly, we sold a substantial amount of non-core assets to reduce our long-term financing obligations resulting in a significant reduction of our revenues and net income during the years ended December 31, 2003, 2004, and 2005. We recorded net pretax charges of approximately $0.1 billion in 2005, $1.1 billion in 2004 and $1.3 billion in 2003, primarily as a result of losses and impairments of assets and equity investments, restructuring charges, and settling litigation. In 2007, we sold our ANR pipeline system and related assets and also completed the offering of common units in El Paso Pipeline Partners, L.P., our master limited partnership.

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

Overview

Our Management s Discussion and Analysis (MD&A) should be read in conjunction with our consolidated financial statements and the accompanying footnotes. MD&A includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing from the statements we make. These risks and uncertainties are discussed further beginning on page 27. Listed below is a general outline of our MD&A:

Our Business includes a summary of our business purpose and description, factors influencing profitability, a summary of our 2007 performance, an outlook for 2008 and an update of our credit profile;

Results of Operations includes a year-over-year analysis beginning on page 44 of the results of our business segments, our corporate activities and other income statement items, including trends that may impact our business in the future;

Liquidity and Capital Resources includes a general discussion beginning on page 65 of our debt obligations, available liquidity, expected 2008 cash flows, and significant factors that could impact our liquidity, as well as an overview of cash flow activity during 2007;

Off Balance Sheet Arrangements, Contractual Obligations, and Commodity-Based Derivative Contracts includes a discussion beginning on page 68 of our (i) off balance sheet arrangements, including guarantees and letters of credit, (ii) other contractual obligations, and (iii) derivative contracts used to manage the price risks associated with our natural gas and oil production and;

Critical Accounting Estimates includes a discussion beginning on page 71 of accounting estimates that involve the use of significant assumptions and/or judgments in the preparation of our financial statements.

Our Business

Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own or have interests in North America s largest interstate natural gas pipeline systems and are a large independent natural gas and oil producer focused on growing our reserve base through disciplined capital investment and portfolio management, cost control and marketing and selling our natural gas and oil production at optimal prices while managing associated price risks.

Factors Influencing Our Profitability. Our pipeline operations are rate-regulated and accordingly we generate profit based on our ability to earn a return in excess of our costs through the rates we charge our customers. Our exploration and production operations generate profits dependent on the prices for natural gas and oil and the volumes we are able to produce, among other factors. Our future profitability in each of our operating segments will be primarily influenced by the following factors:

Pipelines

- Successfully executing on our backlog of committed expansion projects and developing new growth projects in our market and supply areas;
- Contracting and recontracting pipeline capacity with our customers;
- Maintaining or obtaining approval by FERC of acceptable rates and terms of service; and
- Improving operating efficiency.

Exploration and Production

- Increasing our natural gas and oil proved reserve base and production volumes through successful drilling programs and/or acquisitions;
- Finding and producing natural gas and oil at a reasonable cost; and
- Managing price risks to optimize realized prices on our natural gas and oil production.

In addition to these factors, our future profitability will also continue to be impacted by our debt level and related interest costs, the successful resolution of our historical contingencies and completing the orderly exit of our remaining power assets, historical derivative contracts and other remaining non-core assets.

Summary of Overall Performance in 2007. The year ended December 31, 2007 marked our fifth consecutive year of improved profitability, driven primarily by a strong base of earnings and cash flow in our pipeline and exploration and production businesses as well as an interest expense reduction of approximately 20 percent. Across our pipeline system, we made progress on our backlog of committed expansion projects and created El Paso Pipeline Partners, L.P., our master limited partnership. In our exploration and production business, we experienced continued success in our worldwide exploration and drilling programs. These successes allowed us to replace our worldwide natural gas and oil reserves and move forward in high grading our portfolio to improve our cost structure. The following provides additional details of these items and other significant highlights in our core businesses in 2007:

Area of Operations	**Significant Highlights**
Pipelines	Completed and entered into new expansion projects resulting in a current backlog of almost $4 billion.
	Completed the sale of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for net cash proceeds of approximately $3.7 billion
	Implemented FERC approved rate case settlements for El Paso Natural Gas Company and Mojave Pipeline Company
	Completed a $575 million initial public offering of common units for El Paso Pipeline Partners, L.P., a newly formed master limited partnership to enhance the value and financial flexibility of our pipeline assets and provide a lower-cost source of capital for new pipeline growth projects
	Reached an agreement (completed February 2008) to acquire a 50 percent interest in the Gulf LNG Clean Energy project, which is constructing an LNG regasification terminal in Mississippi
Exploration and Production	Met production and cost targets established for 2007 with increased production volumes in each quarter of 2007
	High-graded our portfolio through the acquisition of Peoples for $887 million, adding proved reserves of 298 Bcfe, and progressed on our announced divestiture program
	Replaced 129% of our worldwide natural gas and oil reserves, excluding acquisitions, and 252% including acquisitions
	Achieved success in our exploration programs in Brazil
	Managed price risk through derivative contracts which, when combined with our other positions, provided higher realized commodity prices in 2007 and gives us price protection on approximately two-thirds of our planned 2008 equivalent production.

In addition, our 2007 performance was impacted by our Marketing and Power segments where we continued to reduce the size and volatility of these operations and by corporate costs incurred in conjunction with simplifying and strengthening our balance sheet. Specifically, we incurred (i) mark-to-market losses in our Marketing segment on production-related option contracts and legacy positions, including our Pennsylvania-New Jersey-Maryland (PJM) power contracts and (ii) incremental losses in our Power segment on Brazilian power investments. Additionally, in 2007, we (i) incurred debt extinguishment costs of approximately $291 million in conjunction with repurchasing or refinancing more than $5 billion of debt to strengthen our balance sheet and (ii) resolved certain legal and contractual disputes (see, Item 8, Financial Statements and Supplementary Data, Note 12).

Outlook. For 2008, we expect the current operating trends in our core pipeline and exploration and production businesses to continue with a focus on growing these businesses. For each business, we expect the following:

Pipelines We anticipate that our pipeline operations will continue to provide strong operating results based on its expansion plans, the current levels of contracted capacity, and the status of its rate and regulatory actions. In the pipeline industry, a favorable macroeconomic environment supports continued industry growth. We expect to spend significant pipeline growth capital in 2008. These expenditures should lay the foundation for future growth and the advancement of our significant backlog of committed expansion projects in our market and supply areas and in the development of significant new infrastructure opportunities. Additionally, we will continue to pursue proposed joint venture development projects that would use our incumbent pipeline infrastructure to connect supply areas to areas of high demand in the West, Northeast and Southeast. Finally, we expect to grow our MLP through organic growth opportunities, potential acquisitions, or through future asset contributions. Currently we have in excess of $2 billion in net operating losses available to us to offset any potential tax gains on future asset contributions to the MLP.

Exploration and Production We expect to continue with the momentum established in 2007 and seek to create value through a disciplined and balanced capital investment program. Our drilling programs will focus on growing reserves at reasonable finding and development costs, and growing production efficiently through active cost management. In 2008, our domestic programs will constitute approximately 80 percent of our planned capital and substantially all of our expected production. Performance of these programs will require successful integration and execution of our 2007 acquisitions and our 2008 planned divestitures. In 2008, our International capital is expected to increase approximately 50 percent over our 2007 program. Successful execution of these programs, primarily in Brazil, will require effective project management, partner relations and successful negotiations with regulatory agencies. Our future financial results will be primarily dependent on the continued successful execution of these drilling programs and favorable commodity prices to the extent our anticipated natural gas and oil production is unhedged. Based on our current derivative positions, we anticipate our 2008 hedging program will provide protection from price exposure on a substantial portion of our anticipated natural gas and oil production as previously described.

Credit Profile. Our outstanding debt was $12.8 billion at December 31, 2007. In 2007, we strengthened our credit profile as a result of several actions taken during the year including:

- Reducing debt by approximately $2.6 billion (including debt of our discontinued ANR operations) primarily with proceeds from the sale of ANR;

- Refinancing approximately $2.0 billion of the debt of our subsidiaries SNG, EPNG, and EPEP;

- Receiving upgraded senior unsecured debt ratings for El Paso of Ba3 with a positive outlook from Moody s, BB- with a positive outlook from Standard and Poor s and BB+ from Fitch Ratings and receiving investment grade senior unsecured debt ratings on our pipeline subsidiaries of Baa3 with a positive outlook from Moody s, BB with a positive outlook from Standard and Poor s and an investment grade rating of BBB- from Fitch Ratings. This improvement should provide us a lower cost of capital on planned expansions in our pipeline business;

- Restructuring the El Paso and EPEP revolving credit facilities with improved terms and total capacities of $1.5 billion and $1.0 billion, respectively; and

- Completing our pipeline MLP initial public offering in November 2007 providing us a lower cost of capital for further pipeline growth projects and entering into a $750 million revolving credit facility available to the MLP and non-recourse to El Paso.

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Results of Operations

Overview

As of December 31, 2007, our core operating business segments were Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages our legacy trading activities and a Power segment that has interests in several international power plants. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets all of which are immaterial.

Our management uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments, which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to evaluate our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense from this measure so that investors may evaluate our operating results without regard to our financing methods or capital structure. 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 flows.

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

	2007	2006	2005
		(In millions)	
Segment			
Pipelines	$ 1,265	$ 1,187	$ 924
Exploration and Production	909	640	696
Marketing	(202)	(71)	(837)
Power	(37)	82	(89)
Field Services			285
Segment EBIT	1,935	1,838	979
Corporate and other	(283)	(88)	(521)
Consolidated EBIT	1,652	1,750	458
Interest and debt expense	(994)	(1,228)	(1,295)
Income taxes	(222)	9	331
Income (loss) from continuing operations	436	531	(506)
Discontinued operations, net of income taxes	674	(56)	(96)
Cumulative effect of accounting changes, net of income taxes			(4)
Net income (loss)	$ 1,110	$ 475	$ (606)

The discussions that follow provide additional analysis of the year over year results of each of our business segments, our corporate activities and other income statement items.

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Pipelines Segment

Overview

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

Type	Description	Percent of Total Revenues
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline systems, 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.	77
Usage and Other	Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn. We also earn revenues from the processing and sale of natural gas liquids and other miscellaneous sources.	23

The FERC regulates the rates we can charge our customers. These rates are generally a function of the cost of providing services to our customers, including a reasonable return on our invested capital. Because of 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 changes in natural gas prices, market conditions, regulatory actions, competition, weather and declines in the creditworthiness of our customers. We also experience earnings volatility at certain pipelines when the amount of natural gas used 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, many of our customers have shifted from a traditional dependence 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 plant markets.

We continue to manage our recontracting process to limit the risk of significant impacts on our revenues from expiring contracts. Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on 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 requirements, we attempt to recontract or remarket our capacity at the rates allowed under our tariffs, although we discount these rates at various levels for each of our pipeline systems to remain competitive. Our existing contracts mature at various times and in varying amounts of throughput capacity. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2007. Below are the contract expiration portfolio and the associated revenue expirations for our firm transportation contracts on our wholly and majority owned systems as of December 31, 2007, including those with terms beginning in 2008 or later:

	BBtu/d	Percent of Total Contracted Capacity	Reservation Revenue (In millions)	Percent of Total Reservation Revenue
2008	1,836	8	$ 31	2
2009	2,539	11	170	9
2010	3,388	14	309	17
2011	2,755	11	152	9
2012	3,909	16	222	12
2013 and beyond	9,740	40	929	51
Total	24,167	100	$1,813	100

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In November 2007, we completed an offering of common units in an MLP. We contributed 100 percent of WIC (our wholly owned interstate pipeline transportation business located primarily in Wyoming and Colorado) and 10 percent equity interests in CIG and SNG to the MLP. We have both a 2 percent general partner interest and a 64.8 percent limited partner interest in the MLP.

Summary of Operational and Financial Performance

In 2007, we continued to deliver strong financial performance across all pipelines. We placed several expansion projects in service including Phase I of the SNG Cypress project, TGP Louisiana Deepwater Link project, TGP Triple-T Extension project, TGP Northeast Connexion-New England project and Mexico LPG Burgos project and continued to make significant progress on our backlog of expansion projects. We also successfully resolved our EPNG and Mojave rate cases and restructured and renewed certain customer contracts. During 2007, we benefited from (i) higher realized rates on certain of our systems, (ii) increased throughput, and (iii) increased activity under other various interruptible services.

The level of throughput on our systems can provide evidence of the underlying long-term value of our system capacity. In 2007, increased throughput across our system was a result of broad based increases in power demand from Mexico, California, the Northeast and the Southeast based on underlying growth in electricity demand, colder weather and lower availability of hydroelectric power in the Northwest. We have also experienced higher supply related throughput as a result of our Rockies related expansions.

During 2008, we currently plan on spending $1.6 billion in capital, of which $1.2 billion will be targeted towards our backlog of expansion projects. We intend to build on the growth achieved in 2007 and currently have almost $4 billion in committed expansion projects that comprise our backlog as follows:

Project	*Anticipated In-Service Dates*	*Estimated Cost*	*FERC Approved*