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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

OR

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

For the transition period from to .

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐.

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 ☐ No ☑.

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

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

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 30, 2006 computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $10,437,735,495.

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 21, 2007: 698,334,034

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 2007 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2007.

EL PASO CORPORATION

TABLE OF CONTENTS

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

/d	= per day	MDth	= thousand dekatherms
Bbl	= barrel	MMBtu	= million British thermal units
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	GWh	= thousand megawatt hours
LNG	= liquefied natural gas	MW	= megawatt
MBbls	= thousand barrels	NGL	= natural gas liquids
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units
Mcfe	= thousand cubic feet of natural gas equivalents	Tcfe	= trillion cubic feet of natural gas equivalents

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/or our subsidiaries.

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 regulated 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.

Regulated Natural Gas Transmission. We own or have interests in North America's largest interstate pipeline system with approximately 55,000 miles of pipe that connect North America's major producing basins to its major consuming markets. We also provide approximately 470 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. In February 2007, we sold ANR Pipeline Company (ANR), our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission, which comprised approximately 12,600 miles of pipeline and 236 Bcf of storage capacity. The size, connectivity and diversity of our remaining 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. We are focused on enhancing the value of our transmission business through successful recontracting, continual efficiency improvements through reliable and safe operations, cost management, developing growth projects and prudent capital spending in the United States and Mexico.

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, 2006, we held an estimated 2.4 Tcfe of proved natural gas and oil reserves, exclusive of our equity share in the proved reserves of an unconsolidated affiliate of 222 Bcfe. In this business, we are focused on growing our reserve base through disciplined capital allocation and portfolio management, cost control and marketing and selling our natural gas and oil production at optimal prices while managing associated price risks.

Our operations are conducted through three primary segments: Pipelines, Exploration and Production and Marketing. We also have a Power segment which holds our remaining interests in international power plants in Brazil, Asia and Central America. 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 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 17.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations. These operations are conducted through eight separate, wholly owned pipeline systems and five 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 (i) our ownership of storage capacity through our wholly owned transmission systems, two wholly owned storage facilities, and three partially owned storage systems as well as (ii) 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.

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

- Expanding our systems by attracting new customers, markets or supply sources;
- Identifying and developing growth opportunities;
- Recontracting or contracting available or expiring capacity;

- Focusing on efficiency in our operations and cost control, including efficiencies that may be available across our systems;
- Maintaining the value and ensuring the safety of our pipeline systems and assets; and
- Providing outstanding customer service.

Wholly Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2006 Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2006 (BBtu/d)	2005	2004
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.	14,100	6,961	90	4,534	4,443	4,469
ANR Pipeline[2] (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northeastern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,500	7,311	197	3,954	4,100	4,067
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	10,300	5,650[3]	44	4,179	4,053	4,074
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.	7,500	3,450	60	2,211	1,984	2,163
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.	4,000	3,000	29	2,008	1,902	1,744
Wyoming Interstate (WIC)	Extends from western Wyoming, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	700	2,330	—	1,914	1,572	1,214

Transmission System	Supply and Market Region	As of December 31, 2006 Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2006	2005 (BBtu/d)	2004
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 to customers in the vicinity of Bakersfield, California.	400	407	—	461	161	161
Cheyenne Plains Gas Pipeline[4] (CPG)	Extends from Cheyenne hub in Colorado to various pipeline interconnections near Greensburg, Kansas.	400	838	—	583	433	89

(1) Includes throughput transported on behalf of affiliates.
(2) Sold in February 2007.
(3) This capacity reflects winter-sustainable west-flow capacity of 4,850 MMcf/d and approximately 800 MMcf/d of east-end delivery capacity.
(4) This system was completed in 2005.

As of December 31, 2006, we had the following pipeline and storage expansion projects on our existing systems that have been approved by the FERC:

Project	Capacity (MMcf/d)	Description	Anticipated Completion Date
Louisiana Deepwater Link	850	To construct a 300 foot extension of our 20-inch Grand Isle supply lateral, construct 2,100 feet of 24-inch West Delta supply lateral, abandon 3,100 feet of the 20-inch line connected to the Grand Isle platform, and install appurtenant facilities on Enterprise Product Partners Independence Hub platform located in Mississippi Canyon Block 920.	July 2007
Triple-T Extension	200	To construct 6.2 miles of 24-inch pipeline to extend our existing 30-inch Triple-T Line, beginning in Eugene Island Block 349, to interconnect with Enterprise Products Partners L.P.'s Anaconda System on the El 371 platform, as well as associated piping and other appurtenant facilities.	September 2007
Essex Middlesex Project	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 2007
Northeast ConneXion — New England	108	To construct a compression station and modify compression at six existing facilities on our interstate pipeline system in Pennsylvania, New York, and Massachusetts.	November 2007
Cypress Expansion	500	To construct approximately 177 miles of pipeline to connect our Elba Island facility with markets in Georgia and Florida.	May 2007[1]

(1) Project will consist of three phases. The anticipated completion date is related to phase 1.

Partially Owned Interstate Transmission Systems

Transmission System(1)	Supply and Market Region	As of December 31, 2006 Ownership Interest (Percent)	Miles of Pipeline(2)	Design Capacity(2) (MMcf/d)	Average Throughput(2) 2006 (BBtu/d)	2005	2004
Florida Gas Transmission(3)	Extends from South Texas to South Florida.	50	4,868	2,090	2,018	1,916	2,014
Great Lakes Gas Transmission(4)	Extends from Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,600	2,244	2,376	2,200
Samalayuca Pipeline and Gloria a Dios Compression Station	Extends from U.S.-Mexico border to the state of Chihuahua, Mexico.	50	23	460	442	423	433
San Fernando Pipeline	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) These systems are accounted for as equity investments.
(2) Miles, volumes and average throughput represent the systems' totals and are not adjusted for our ownership interest.
(3) We have a 50 percent equity interest in Citrus Corp. (Citrus), which owns this system.
(4) Sold in February 2007.

Partially Owned Intrastate Transmission Systems

We also have a 50 percent interest in WYCO Development, L.L.C. (WYCO). WYCO owns a state regulated intrastate gas pipeline extending 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.

Underground Natural Gas Storage Entities

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

Storage Entity	As of December 31, 2006 Ownership Interest (Percent)	Storage Capacity(1) (Bcf)	Location
Bear Creek Storage	100	58	Louisiana
ANR Storage(2)	100	56	Michigan
Blue Lake Gas Storage(2)	75	47	Michigan
Eaton Rapids Gas Storage(2)(3)	50	13	Michigan
Young Gas Storage(3)	48	6	Colorado

(1) Approximately 135 Bcf is contracted to affiliates. Amounts are not adjusted for our ownership interest.
(2) Sold in February 2007.
(3) This system is accounted for as an equity investment.

LNG Facility

We own an LNG receiving terminal located on Elba Island, near Savannah, Georgia with a peak sendout capacity of 1,215 MMcf/d and a base load sendout capacity of 806 MMcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

Markets and Competition

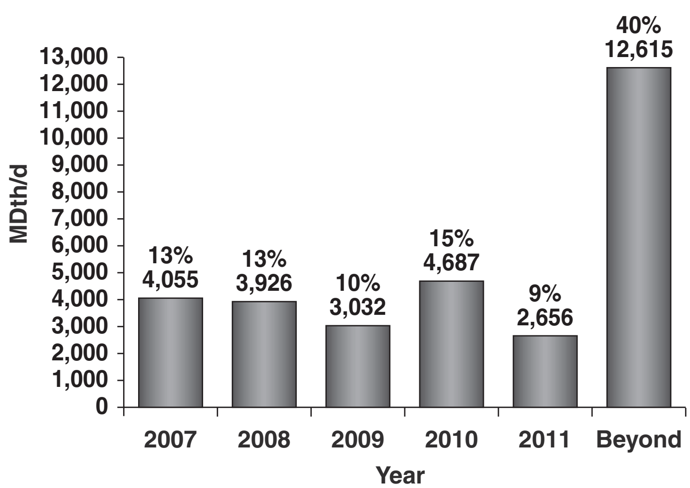
We provide natural gas services to a variety of customers, including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy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

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing their delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. These LNG delivery systems, however, 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 contracts with 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 the contracted capacity that expires by year over the next five years and thereafter.

Contract Expirations[1]



[1] Includes ANR sold in February 2007.

The following table details information related to our customers, contracts, the markets we serve, and the competition faced by each of our wholly owned pipeline transmission systems as of December 31, 2006. Our 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 actually transported, stored, injected or withdrawn.

TGP

Customer Information	Contract Information	Competition
Approximately 460 firm and interruptible customers, none of which individually represents more than 10 percent of revenues	Approximately 470 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. In the offshore areas of the Gulf of Mexico, factors such as the distance of the supply fields from the pipeline, relative basis pricing of the pipeline receipt points, and costs of intermediate gathering or required processing of the natural gas to be transported may influence determinations of whether natural gas is ultimately attached to the TGP system.

ANR[1]

Customer Information	Contract Information	Competition
Approximately 290 firm and interruptible customers	Approximately 670 firm transportation contracts. Weighted average remaining contract term of approximately five years.	In its market areas, ANR competes directly with Guardian Pipeline, for markets in Wisconsin. ANR also competes directly with other interstate pipelines in the northeast markets to serve electric generation and local distribution companies. In its supply areas, ANR competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR's principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to Wisconsin and the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.
Major Customer: We Energies (799 BBtu/d)	Expire in 2007-2016.	

[1] Sold in February 2007

EPNG

Customer Information	Contract Information	Competition
Approximately 160 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 alternative energy sources that are used to generate electricity such as hydroelectric, nuclear, wind, 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		
(101 BBtu/d)	Expires in 2007.	
(187 BBtu/d)	Expires in 2009.	
(561 BBtu/d)	Expire in 2010 - 2011.	
Southwest Gas Corporation		
(11 BBtu/d)	Expires in 2008.	
(476 BBtu/d)	Expire in 2011 - 2015.	

SNG

Customer Information	Contract Information	Competition
Approximately 274 firm and interruptible customers	Approximately 200 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, nuclear 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 services.
Major Customers:		
Atlanta Gas Light Company (959 BBtu/d)	Expire in 2009-2015.	
Southern Company Services (418 BBtu/d)	Expire in 2010-2018.	
Alabama Gas Corporation (413 BBtu/d)	Expire in 2010-2013.	
Scana Corporation (316 BBtu/d)	Expire in 2007-2019.	

CIG

Customer Information	Contract Information	Competition
Approximately 110 firm and interruptible customers	Approximately 170 firm transportation contracts. Weighted average remaining contract term of approximately six 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, a new 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 a new interstate pipeline and other existing interstate pipelines that are directly connected to its supply sources.
Major Customers:		
Public Service Company of Colorado		
(187 BBtu/d)	Expires in 2008.	
(9 BBtu/d)	Expires in 2009.	
(1,106 BBtu/d)	Expire in 2012-2014.	
Williams Power Company		
(30 BBtu/d)	Expires in 2007.	
(53 BBtu/d)	Expires in 2009.	
(348 BBtu/d)	Expire in 2010 - 2013.	
Anadarko Petroleum Corporation and subsidiaries		
(10 BBtu/d)	Expires in 2007.	
(60 BBtu/d)	Expires in 2008.	
(12 BBtu/d)	Expires in 2009.	
(208 BBtu/d)	Expire in 2010 - 2015.	

WIC

Customer Information	Contract Information	Competition
Approximately 50 firm and interruptible customers	Approximately 50 firm transportation contracts. Weighted average remaining contract term of approximately six years.	WIC competes with existing pipelines and a new interstate pipeline to provide transportation services to pipeline interconnects in northeast Colorado and western Wyoming.
Major Customers:		
Williams Power Company		
(25 BBtu/d)	Expires in 2008.	
(678 BBtu/d)	Expire in 2010-2021.	
Anadarko Petroleum Corporation and subsidiaries		
(25 BBtu/d)	Expires in 2008.	
(385 BBtu/d)	Expire in 2011-2017.	

MPC

Customer Information	Contract Information	Competition
Approximately 20 firm and interruptible customers	Approximately six firm transportation contracts. Weighted average remaining contract term of approximately seven years.	MPC faces competition from other existing and proposed pipelines, and alternative energy sources that are used to generate electricity such as hydroelectric, nuclear, wind, coal and fuel oil. In addition, construction of facilities to bring LNG into California and northern Mexico are underway.
Major Customers:		
Los Angeles Department of Water and Power		
(50 BBtu/d)	Expires in 2015.	
EPNG		
(312 BBtu/d)		
Los Angeles Department of Water and Power		
(50 BBtu/d)	Expires in 2007.	

CPG

Customer Information	Contract Information	Competition
Approximately 30 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 are existing and currently under construction to transport Rocky Mountain gas to other markets.
Major Customers:		
Oneok Energy Services Company L.P.		
(195 BBtu/d)	Expire in 2015.	
Encana Marketing (USA) Inc.		
(170 BBtu/d)	Expire in 2015.	
Anadarko Petroleum Corporation		
(195 BBtu/d)	Expire in 2015-2016.	

Exploration and Production Segment

Our Exploration and Production segment's current 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, 2006, we controlled over 2.9 million net leasehold acres. During 2006, daily equivalent natural gas production averaged approximately 730 MMcfe/d and our proved natural gas and oil reserves at December 31, 2006, were approximately 2.4 Tcfe, excluding 0.2 Tcfe related to our unconsolidated investment in Four Star Oil & Gas Company. 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 and coal bed methane 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 2006, we invested $500 million on capital projects and production averaged 345 MMcfe/d. The principal operating areas are listed below:

		2006		
Region	**Description**	**Net Acres**	**Capital Investment**	**Average Production (MMcfe/d)**
East Texas/north Louisiana (Arklatex)	Concentrated land position primarily focused on tight gas sands production in the Travis Peak/Hosston and Cotton Valley formations.	104,000	$203 million	122
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.	172,000	$49 million	64
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 gas production in the Hugoton field.	319,000	$56 million	28
Rocky Mountain (Rockies)	Primarily in Wyoming and Utah with a focus in the Powder River and Uintah basins, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with non-operated coal bed methane fields. We also operate the Altamont and Bluebell processing plants and related gathering systems in Utah.	364,000	$120 million	55
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.	605,000	$72 million	76

Included in our Mid-Continent region is our interest in 127,000 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 22 wells through the end of 2006.

Texas Gulf Coast. The Texas Gulf Coast region focuses on developing and exploring for tight gas sands in south Texas. In this area, we have an inventory of over 10,000 square miles of three dimensional (3D) seismic data. During 2006, we invested $217 million on capital projects and production averaged 187 MMcfe/d. The principal operating areas are listed below:

		2006		
Region	**Description**	**Net Acres**	**Capital Investment**	**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.	81,000	$111 million	123
Upper Gulf Coast Wilcox	Located onshore Texas Gulf Coast, including Renger, Dry Hollow and Speaks fields in Lavaca County. In this area, average well depth is between 13,000 to 18,000 feet.	31,000	$60 million	32
South Texas Wilcox	Includes the Bob West and Roleta fields in Zapata County where in January 2007 we completed the acquisition described below.	25,000	$29 million	27

In January 2007, we acquired operated producing properties and undeveloped acreage in Zapata County, Texas with an average working interest of 85 percent. These properties complement our existing south Texas Wilcox operations providing a re-entry into the Lobo trend and a multi-year drilling inventory with significant additional exploration and development drilling opportunities. The 23,000 net acres acquired had production of approximately 12 MMcfe/d on the acquisition date. Estimated proved reserves at the acquisition date were approximately 84 Bcfe, of which approximately 73 percent was undeveloped.

Gulf of Mexico Shelf and south Louisiana. Our Gulf of Mexico shelf and south Louisiana operations are generally characterized by relatively high initial production rates, resulting in near-term cash flows, and high decline rates. During 2006, we invested $310 million on drilling, workover and facilities projects and production averaged 174 MMcfe/d. The principal operating areas are listed below:

		2006		
Region	**Description**	**Net Acres**	**Capital Investment**	**Average Production (MMcfe/d)**
Gulf of Mexico Shelf	Primarily deep shelf drilling interests in 173 Blocks (generally nine square miles) south of the Louisiana, Texas and Alabama shorelines focused on deep (greater than 12,000 feet) gas reserves in relatively shallow waters depths (less than 400 feet).	688,000	$246 million	163
South Louisiana	Primarily in Vermillion Parish and associated bays and waters in southwestern Louisiana covered by the Catapult 3D seismic project. We have internally processed 2,600 square miles of contiguous 3D seismic data in this project.	34,000	$64 million	11

Unconsolidated Investment in Four Star. We own a 43.1 percent investment in Four Star. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and the Gulf of Mexico. During 2006, our proportionate share of Four Star's daily equivalent natural gas production averaged approximately 68 MMcfe/d and at December 31, 2006, proved natural gas and oil reserves, net to our interest, were 222 Bcfe. In January 2007, Four Star acquired 79 wells in the San Juan basin that had daily production of approximately 5 MMcfe/d and proved reserves of 16 Bcfe, net to our interest, on the acquisition date.

International

Brazil. Our Brazil operations cover approximately 361,000 net acres. These 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. In 2006, we invested $80 million in capital projects in Brazil and production averaged approximately 24 MMcfe/d from the Pescada Arabaiana Fields.

Egypt. Our Egypt 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, which is in the seismic, exploratory drilling and evaluation phases of the project. Our total funding commitment to the South Feiran concession is $3 million. In addition, we were the winning bidder of the South Mariut Block in the second quarter of 2006 with a $3 million payment due on final receipt of the concession and an agreement for a $22 million firm working commitment over three years. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We expect to receive formal governmental approvals and sign the concession agreement during the first quarter of 2007.

Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents our estimated proved reserves based on our internal reserve report as of December 31, 2006 by region and classification as well as our 2006 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					2006 Production (MMcfe)
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	Total (Percent)	
Reserves and Production by Region						
United States						
Onshore	1,308,742	28,947	1,060	1,488,789	62%	126,093
Texas Gulf Coast	344,596	2,265	8,004	406,209	17%	68,269
Gulf of Mexico Shelf and south Louisiana	209,897	9,467	948	272,384	11%	63,537
Total United States	1,863,235	40,679	10,012	2,167,382	90%	257,899
Brazil	56,383	31,847	—	247,466	10%	8,619
Total	1,919,618	72,526	10,012	2,414,848	100%	266,518
Unconsolidated investment in Four Star	167,046	2,947	6,209	221,984	100%	24,663
Reserves by Classification						
United States						
Producing	1,251,019	22,415	7,402	1,429,923	66%	
Non-Producing	217,881	7,201	1,263	268,665	12%	
Undeveloped	394,335	11,063	1,347	468,794	22%	
Total proved	1,863,235	40,679	10,012	2,167,382	100%	
Brazil						
Producing	19,931	489	—	22,864	9%	
Non-Producing	3,405	335	—	5,418	2%	
Undeveloped	33,047	31,023	—	219,184	89%	
Total proved	56,383	31,847	—	247,466	100%	
Worldwide						
Producing	1,270,950	22,904	7,402	1,452,787	60%	
Non-Producing	221,286	7,536	1,263	274,083	11%	
Undeveloped	427,382	42,086	1,347	687,978	29%	
Total proved	1,919,618	72,526	10,012	2,414,848	100%	
Unconsolidated investment in Four Star						
Producing	136,489	2,874	5,068	184,140	83%	
Non-Producing	2,733	—	26	2,892	1%	
Undeveloped	27,824	73	1,115	34,952	16%	
Total Four Star	167,046	2,947	6,209	221,984	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, prepared an estimate on 84 percent of our consolidated natural gas and oil reserves. Additionally, Ryder Scott prepared an estimate of 80 percent of the proved 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 prescribed by the SEC. These rules indicate that the standard of "reasonable certainty" be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate.

In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. 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, 2006, (ii) our interest in natural gas and oil wells at December 31, 2006 and (iii) our exploratory and development wells drilled during the years 2004 through 2006. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		**Undeveloped**		**Total**	
Acreage	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
United States						
Onshore	874,525	556,828	1,612,025	1,135,010	2,486,550	1,691,838
Texas Gulf Coast	93,573	73,373	91,230	63,452	184,803	136,825
Gulf of Mexico Shelf and south Louisiana	508,716	359,064	401,075	363,046	909,791	722,110
Total	1,476,814	989,265	2,104,330	1,561,508	3,581,144	2,550,773
Brazil	49,262	17,242	1,158,643	343,563	1,207,905	360,805
Egypt	—	—	64,740	12,948	64,740	12,948
Worldwide Total	1,526,076	1,006,507	3,327,713	1,918,019	4,853,789	2,924,526

In the United States, our net developed acreage is concentrated primarily in the Gulf of Mexico (36 percent), Utah (13 percent), Texas (9 percent), Alabama (9 percent), New Mexico (9 percent), Oklahoma (8 percent) and Louisiana (7 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (31 percent), the Gulf of Mexico (22 percent), Wyoming (10 percent), West Virginia (8 percent), Indiana (7 percent), Alabama (5 percent), Texas (4 percent) and Louisiana (3 percent). Approximately 23 percent, 20 percent and 8 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2007, 2008 and 2009. Approximately 16 percent, 25 percent and 12 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2007, 2008 and 2009. Approximately 33 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2008. 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.

	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2006	
Productive Wells	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2][3]	Gross[1]	Net[2]
United States								
Onshore	3,880	2,954	801	548	4,681	3,502	52	38
Texas Gulf Coast	843	703	—	—	843	703	6	5
Gulf of Mexico Shelf and south Louisiana	187	122	58	40	245	162	6	4
Total	4,910	3,779	859	588	5,769	4,367	64	47
Brazil	4	1	6	2	10	3	—	—
Worldwide Total	4,914	3,780	865	590	5,779	4,370	64	47

	Net Exploratory[2]			Net Development[2]		
Wells Drilled	2006	2005	2004	2006	2005	2004
United States						
Productive	106	86	13	319	279	298
Dry	6	2	10	2	4	3
Total	112	88	23	321	283	301
Brazil						
Productive	—	—	—	—	—	—
Dry	—	—	1	—	—	—
Total	—	—	1	—	—	—
Worldwide						
Productive	106	86	13	319	279	298
Dry	6	2	11	2	4	3
Total	112	88	24	321	283	301

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

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

(3) At December 31, 2006, we operated 3,957 of the 4,370 net productive wells.

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.

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:

	2006	2005	2004
Consolidated Volumes, Prices, and Costs per Unit:			
Net Production Volumes			
United States			
Natural gas (MMcf)	213,262	206,714	238,009
Oil, condensate and NGL (MBbls)	7,439	7,516	8,498
Total (MMcfe)	257,899	251,807	288,994
Brazil[1]			
Natural gas (MMcf)	7,140	15,578	6,848
Oil, condensate and NGL (MBbls)	247	620	320
Total (MMcfe)	8,619	19,300	8,772
Worldwide			
Natural gas (MMcf)	220,402	222,292	244,857
Oil, condensate and NGL (MBbls)	7,686	8,136	8,818
Total (MMcfe)	266,518	271,107	297,766
Total (MMcfe/d)	730	743	814
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Excluding hedges	$ 6.77	$ 7.92	$ 6.02
Including hedges	$ 6.50	$ 6.69	$ 5.94
Brazil			
Excluding hedges	$ 2.61	$ 2.33	$ 2.01
Including hedges	$ 2.61	$ 2.33	$ 2.01
Worldwide			
Excluding hedges	$ 6.64	$ 7.53	$ 5.90
Including hedges	$ 6.38	$ 6.39	$ 5.83
Oil, Condensate, and NGL Average Realized Sales Price ($/Bbl)			
United States			
Excluding hedges	$ 55.95	$ 45.86	$ 34.44
Including hedges	$ 55.95	$ 45.86	$ 34.44
Brazil			
Excluding hedges	$ 64.02	$ 53.42	$ 43.01
Including hedges	$ 54.48	$ 42.42	$ 39.19
Worldwide			
Excluding hedges	$ 56.21	$ 46.43	$ 34.75
Including hedges	$ 55.90	$ 45.60	$ 34.61
Average Transportation Cost			
United States			
Natural gas ($/Mcf)	$ 0.24	$ 0.20	$ 0.17
Oil, condensate and NGL ($/Bbl)	$ 0.85	$ 0.69	$ 1.16
Worldwide			
Natural gas ($/Mcf)	$ 0.23	$ 0.18	$ 0.17
Oil, condensate and NGL ($/Bbl)	$ 0.82	$ 0.63	$ 1.12
Average Production Cost($/Mcfe)[2]			
United States			
Average lease operating cost	$ 0.97	$ 0.73	$ 0.62
Average production taxes	0.28	0.27	0.11
Total production cost	$ 1.25	$ 1.00	$ 0.73

	2006	2005	2004
Brazil			
Average lease operating cost	$ 0.28	$ 0.42	$ —
Average production taxes	0.53	—	—
Total production cost	$ 0.81	$ 0.42	$ —
Worldwide			
Average lease operating cost	$ 0.95	$ 0.72	$ 0.60
Average production taxes	0.29	0.24	0.11
Total production cost	$ 1.24	$ 0.96	$ 0.71
Unconsolidated affiliate volumes (Four Star)[3]			
Natural gas (MMcf)	18,140	6,689	
Oil, condensate and NGL (MBbls)	1,087	359	
Total equivalent volumes			
MMcfe	24,663	8,844	
MMcfe/d	68	24	

(1) Production volumes in Brazil decreased due to a contractual reduction of our ownership interest in the Pescada-Arabaiana Field in 2006.
(2) Production cost includes lease operating costs and production related taxes (including ad valorem and severance taxes).
(3) Includes our proportionate share of volumes in Four Star which was acquired in the third quarter of 2005.

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:

	2006	2005	2004
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 2	$ 643	$ 33
Unproved	34	143	32
Development Costs	738	503	395
Exploration Costs:			
Delay rentals	6	3	7
Seismic acquisition and reprocessing	23	7	29
Drilling	294	133	149
Asset Retirement Obligations	3	1	30
Total full cost pool expenditures	1,100	1,433	675
Non-full cost pool expenditures	8	22	11
Total cost incurred[1]	$1,108	$1,455	$686
Acquisition of unconsolidated investment in Four Star[1]	$ —	$ 769	$ —
Brazil and Other International			
Acquisition Costs:			
Proved	$ 2	$ 8	$ 69
Unproved	1	1	3
Development Costs	40	6	1
Exploration Costs:			
Seismic acquisition and reprocessing	7	7	15
Drilling	46	8	10

	2006	2005	2004
		(In millions)	
Asset Retirement Obligations	—	—	3
Total full cost pool expenditures	96	30	101
Non-full cost pool expenditures	—	—	3
Total cost incurred	$ 96	$ 30	$104
Worldwide			
Acquisition Costs:			
Proved	$ 4	$ 651	$102
Unproved	35	144	35
Development Costs	778	509	396
Exploration Costs:			
Delay rentals	6	3	7
Seismic acquisition and reprocessing	30	14	44
Drilling	340	141	159
Asset Retirement Obligations	3	1	33
Total full cost pool expenditures	1,196	1,463	776
Non-full cost pool expenditures	8	22	14
Total cost incurred[(1)]	$1,204	$1,485	$790
Acquisition of unconsolidated investment in Four Star[(1)]	$ —	$ 769	$ —

(1) In 2005, amount includes $179 million of deferred income tax adjustments 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 $192 million in 2006, $247 million in 2005 and $156 million in 2004 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

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, 2006, we had entered into derivative contracts on approximately 133,000 BBtu of our anticipated natural gas production in 2007 and approximately 21,000 BBtu of our total anticipated natural gas production from 2008 through 2012. We also have derivative contracts on our Brazilian oil production that provides us with a fixed price on approximately 192 MBbls in 2007. 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.

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 historical trading activities, which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2006, we managed the following types of contacts:

- *Production-Related Natural Gas and Oil Derivatives.* 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.
- *Historical Natural Gas and Power Contracts.* Includes supply agreements with Midland Cogeneration Venture and power contracts in the Pennsylvania-New Jersey-Maryland region.

Production-Related Natural Gas and Oil Derivatives

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 on page 12. For a further discussion of the entirety of El Paso's production-related price risk management activities, refer to our liquidity discussion beginning on page 62. As of December 31, 2006, Marketing's contracts provided El Paso with price protection on the following quantities of future natural gas and oil production:

	2007	2008	2009
Natural Gas (TBtu)			
Volumes with floor price	89	18	17
Volumes with ceiling price	—	18	17
Oil (MBbls)			
Volumes with floor and ceiling prices	1,009	930	—

Contracts Related to Historical 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. We typically refer to the fixed reservation cost as a demand charge. 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, 2006:

	Alliance Pipeline	Affiliated Pipelines(1)	Other Pipelines
Daily capacity (MMBtu/d)	160,000	521,000	156,000
Expiration	October 31, 2007(2)	2008 to 2028	2007 to 2026
Receipt points	AECO Canada	Various	Various
Delivery points	Chicago	Various	Various

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

(2) In December 2006, we paid a third party to assume our capacity obligations under this contract beginning November 1, 2007 through the contractual term of the contract which ends in 2015.

Other natural gas contracts. As of December 31, 2006, we had a variety of natural gas derivative contracts and long-term gas supply obligations, including ten significant physical natural gas contracts with power plants associated with our historical trading activities. 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 21,500 to 130,000 MMBtu/d.

Power contracts. As of December 31, 2006, we had four derivative contracts that require us to swap locational differences in power prices between four power plants in the Pennsylvania-New Jersey-Maryland (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 2013 and 1,700 GWh from 2014 to 2016. Additionally, these contracts require us to provide installed capacity of approximately 71 GWh 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 in 2005 and 2006.

Markets and Competition

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 power producers with varying scopes of operations and financial resources.

Power Segment

As of December 31, 2006, our Power segment primarily included the ownership and operation of investments in international power generation facilities listed in the table 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 currently expect to complete the sale of substantially all of the Asian and Central American facilities in the first half of 2007.

Project	Area	El Paso Ownership Interest	Gross Capacity	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
		(Percent)	(MW)			
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
Saba Power Co.	Pakistan	94	128	Pakistan Water and Power	2029	Residual Fuel Oil
Khulna Power Co.	Bangladesh	74	113	BPDB	2013	Heavy Fuel Oil
Tipitapa	Nicaragua	60	51	Union Fenosa	2014	Heavy Fuel Oil

(1) Ownership of these plants will transfer to the power purchaser no later than January 2008.
(2) The power purchaser has approached us with the opportunity to sell them our interest in the facility.

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 2006 throughput of 1,197 MMcf/d and 1,037 BBtu/d, unadjusted for our ownership interest. We also have an interest in a pipeline project in Brazil that is in the development stage.

Regulatory Environment

Pipelines. 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 service to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage, LNG terminalling 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 the 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.

Exploration and Production. 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, 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 spills and oil pollution liability.

Power. 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 (including differing interpretations) over time.

Environmental

A description of our environmental activities is included in Part II, Item 8 Financial Statements and Supplementary Data, Note 13.

Employees

As of February 23, 2007, we had approximately 5,050 full-time employees, of which 224 employees are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of February 27, 2007, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso	2003	47
D. Mark Leland	Executive Vice President and Chief Financial Officer of El Paso	2005	45
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	50
Brent Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	45
Susan B. Ortenstone	Senior Vice President (Human Resources and Administration) of El Paso	2003	50
James C. Yardley	Executive Vice President of El Paso, Chairman of the Board of El Paso's Pipeline Group and Chairman of the Board and President of Southern Pipeline Group	2005	55
James J. Cleary	President of Western Pipeline Group	2005	52
Daniel B. Martin	Senior Vice President of Pipeline Operations	2005	50

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.

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.

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.

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 supervisory and asset management 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.

James C. Yardley has been Executive Vice President of El Paso and Chairman of the Board of El Paso's Pipeline Group since August 2006. He has been Chairman of the Board and President of Southern Natural Gas Company since May 2005, Director of Southern Natural Gas Company since November 2001 and President of Southern Natural Gas Company since May 1998. He served as Vice President, Marketing and Business Development for Southern Natural Gas Company from April 1994 to April 1998. Prior to that time, Mr. Yardley worked in various capacities with Southern Natural Gas and Sonat Inc. since 1978.

James J. Cleary has been President and Director 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 through 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 since 1979.

Daniel B. Martin has been Director of ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company and Tennessee Gas Pipeline Company since May 2005. 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 of ANR Pipeline Company and Colorado Interstate Gas Company since January 2001. Prior to that time, Mr. Martin worked in various capacities with Tennessee Gas Pipeline Company since 1978.

Available Information

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

ITEM 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 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 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, to renegotiate existing contracts as they expire 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 gas supply sources, such as LNG;
- decreased natural gas demand due to various factors, including increases in prices and the availability or popularity of other energy sources such as hydroelectric, nuclear, wind, and coal power 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;
- 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.

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

Substantially all of our pipeline subsidiaries' revenues are generated under contracts which expire periodically and must be renegotiated and extended or replaced. 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 transmission, 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 oil producing countries.

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 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 and regulations, 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, or other factors beyond our control, that may be material;

- the lack of future growth; 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.

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, 2006 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 factors that are beyond our control.

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

We could incur financial losses in the future as a result of volatility in the market values of the energy commodities we trade, or if one of our counterparties fails to perform under a contract. The valuation of these financial instruments involves estimates. Changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. To the extent we hedge our commodity price exposure and interest rate exposure, we forego the benefits we would otherwise experience if commodity prices or interest rates were to change favorably. The use of derivatives could require the posting of collateral with our counterparties which can 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 8.

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

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

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 and exploration and production projects in Egypt, 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, 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. In addition, as we exit businesses, we have experienced substantial reductions and turnover in our workforce that previously supported the ownership and operation of such assets 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 including those involving allegations associated with our legacy trading business, our oil and gas reserves, and the accounting treatment of certain hedges of our anticipated natural gas production. These investigations involve, among others, one or more of the following governmental agencies: the SEC, FERC, the U.S. Department of Transportation Office of Pipeline Safety and the Department of Justice. We are cooperating with the governmental agency or agencies in each of these investigations. The outcome of each of these investigations and the costs to the Company of responding and participating in these on-going 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 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, local and tribal regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. In setting authorized rates of return in recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risk as interstate pipelines. The inclusion of these lower risk companies may create downward pressure on tariff rates when subjected to review by the FERC in future rate proceedings. Shippers on other pipelines have sought reductions from the FERC for the rates charged by pipelines to their customers. If our pipelines' tariff rates were reduced or re-designed in a future proceeding, if our pipelines' volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition or because of regulatory pressure, the profitability of our pipeline businesses could be reduced.

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

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 exactly the 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 13. These uncertainties include:

- estimating pollution control and clean up costs, including for 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; and
- evaluating and understanding environmental laws and regulations, including their interpretation and enforcement.

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, proposed federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in GHG emissions. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. These actions could also impact the consumption of natural gas and oil, thereby affecting our pipeline and exploration and production operations.

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 13). 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 our senior unsecured indebtedness are below investment grade, currently rated B2 with a positive outlook by Moody's Investor Service (Moody's) and B 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 12, 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 CIG, EPNG, TGP and 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.

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.

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 13, and are incorporated herein by reference.

Various shareholder class actions were filed in the U.S. District Court for the Southern District of Texas, Houston Division commencing on July 18, 2002. They have now been consolidated into the action styled as follows: *Oscar S. Wyatt, Jr et al v. El Paso Corporation, William Wise, H. Brent Austin, Ralph Eads, Rodney D. Erskine, Ronald Kuehn, Jr., D. Dwight Scott, Credit Suisse First Boston LLC and PricewaterhouseCoopers LLP.*

Environmental Proceedings

Natural Buttes. In May 2003, we met with the EPA to discuss potential prevention of significant deterioration violations due to a possible de-bottlenecking modification at our facility in Utah. The EPA issued an Administrative Compliance Order as to this and other matters and we entered into settlement negotiations with the EPA. In September 2005, we were informed that the EPA referred this matter to the U.S. Department of Justice. We have since entered into tolling agreements to facilitate continuing settlement discussions. In October 2006, the EPA indicated that it would settle this matter for a penalty of $420,000, largely related to alleged excess emissions from an improperly installed flare. We have reserved our anticipated settlement amount and are formulating a proposal for a supplemental environmental project, which would be conducted in lieu of a substantial portion of any eventual penalty. We believe the resolution of this matter will not have a material adverse effect on our operating results or financial condition.

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

None.

PART II

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

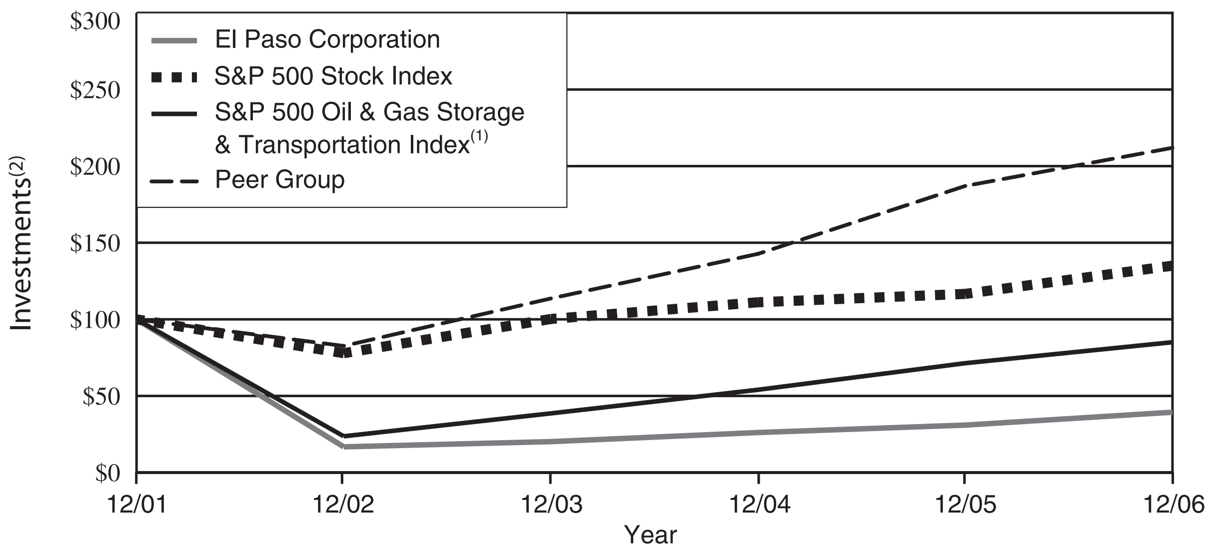
Our common stock is traded on the New York Stock Exchange under the symbol EP. As of February 26, 2007, we had 30,164 stockholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

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
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
2005			
Fourth Quarter	$14.07	$10.78	$0.04
Third Quarter	14.16	11.13	0.04
Second Quarter	11.87	9.30	0.04
First Quarter	13.15	10.01	0.04

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2001 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 2006 included the following companies: Anadarko Petroleum Corp., Apache Corp., CenterPoint Energy Inc., Devon Energy Corp., Dominion Resources, Inc., Enbridge, Inc., Equitable Resources, Inc., Kinder Morgan, Inc., NiSource, Inc., ONEOK, Inc., PG&E Corp., PPL Corp., Questar Corp., Sempra Energy, Southern Union Co., Transcanada Corp., Western Gas Resources, Inc. and Williams Companies, Inc.

COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS



	12/01	12/02	12/03	12/04	12/05	12/06
El Paso Corporation	$100	$16.78	$ 20.18	$ 26.12	$ 30.97	$ 39.37
S&P 500 Stock Index	$100	$77.90	$100.25	$111.15	$116.61	$135.03
S&P 500 Oil & Gas Storage & Transportation Index[1]	$100	$23.68	$ 38.62	$ 54.04	$ 71.38	$ 85.07
Peer Group	$100	$82.63	$113.63	$142.76	$187.06	$211.96

(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 14, 2007, we declared a quarterly dividend of $0.04 per share of our common stock, payable on April 2, 2007, to shareholders of record as of March 2, 2007. 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.

ITEM 6: SELECTED FINANCIAL DATA

The following presents selected historical financial data 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. This information has been adjusted in all periods to reflect the reclassification of ANR, our Michigan storage assets and our 50% interest in Great Lakes Gas Transmission as well as our Macae power facility 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,				
	2006	2005	2004	2003	2002
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,281	$ 3,359	$ 4,783	$ 5,596	$ 5,909
Income(loss) from continuing operations	$ 531	$ (506)	$ (1,032)	$ (795)	$ (1,531)
Net income(loss) available to common stockholders	$ 438	$ (633)	$ (947)	$ (1,883)	$ (1,875)
Basic earnings (loss) per common share from continuing operations	$ 0.73	$ (0.82)	$ (1.61)	$ (1.33)	$ (2.74)
Diluted earnings (loss) per common share from continuing operations	$ 0.72	$ (0.82)	$ (1.61)	$ (1.33)	$ (2.74)
Cash dividends declared per common share	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.87
Basic average common shares outstanding	678	646	639	597	560
Diluted average common shares outstanding	739	646	639	597	560
Financial Position Data:					
Total assets	$27,261	$31,840	$31,383	$36,968	$41,947
Long-term financing obligations, less current maturities	13,329	16,282	17,506	19,193	15,594
Securities of subsidiaries	31	31	367	447	3,421
Stockholders' equity	4,186	3,389	3,438	4,346	5,749

Over the past five years, our financial position and operating results have been substantially affected by the restructuring and realignment of our business around our core pipeline and exploration and production operations. As part of this realignment, since 2003 we have sold a substantial amount of non-core assets to reduce our long-term financing obligations resulting in a substantial reduction of our revenues and net income during this period. During this period, we recorded net pretax charges of approximately $0.1 billion in 2005, $1.1 billion in 2004, $1.3 billion in 2003, and $1.8 billion in 2002, primarily as a result of losses and impairments of assets and equity investments, restructuring charges, and settling litigation associated with the western energy crisis in 2000 to 2001.

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. This information has been adjusted in all periods to reflect the reclassification of ANR, our Michigan storage assets and our 50% interest in Great Lakes Gas Transmission as well as our Macae power facility as discontinued operations. 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 22. Listed below is a general outline of our MD&A to help understand our operations and the business environment in which we operate.

Our Business — a summary of our business purpose and description, profitability drivers, a summary of our 2006 performance, what to expect in our business in 2007 and an update of our credit metrics;

Results of Operations — a year-over-year analysis beginning on page 37 of the results of our business segments, our corporate activities and other income statement items;

Capital Resources and Liquidity — a general discussion beginning on page 62 of our debt obligations, available liquidity, expected 2007 cash flows, and significant factors that could impact our liquidity, as well as an overview of cash flow activity during 2006;

Off Balance Sheet Arrangements, Contractual Obligations, and Commodity-Based Derivative Contracts — a discussion beginning on page 67 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 — a discussion beginning on page 70 of accounting estimates that involve the use of significant assumptions and/or judgments in the preparation of our financial statements.

Our Business

Primary Business Purpose and Description. 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 allocation and portfolio management, cost control and marketing and selling our natural gas and oil production at optimal prices while managing associated price risks.

Drivers of 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. The profitability of our exploration and production operations is 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 these operations will be primarily driven by the following factors:

Pipelines

- Expanding our existing pipeline systems to meet demand growth and gain access to new supply areas and sources;
- Contracting and recontracting pipeline capacity with our customers;
- Maintaining approval by FERC of acceptable rates and terms of service, including successfully resolving rate cases; and
- Improving operating efficiency.

Exploration and Production / Marketing

— Increasing our natural gas and oil proved reserve base and production volumes through successful drilling programs or acquisitions; and

— Finding and producing natural gas and oil at a reasonable cost.

In addition to these factors, our future profitability will also be impacted by our debt level and related interest costs, 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 2006. During 2006, our financial performance was relatively stable. Our pipeline business experienced substantial earnings growth and continued to provide a strong base of earnings and cash flow. Our exploration and production business experienced continued success in its drilling programs resulting in higher production levels during each quarter of the year. However, lower than planned production volumes in 2006 and lower than expected commodity prices impacted our ability to attain the operational and financial targets for the year we previously established. The table that follows and our individual segment discussions provide further analysis of our operating results.

Area of Operations	Significant Highlights
Pipelines.	Announced the sale of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission
	Implemented a FERC approved rate case settlement for Colorado Interstate Gas Company and filed a rate case settlement for approval with the FERC for El Paso Natural Gas Company
	Re-contracted or contracted available or expiring capacity
	Completed several expansion projects and proceeded with other expansion projects in our pipeline systems and at our Elba Island LNG facility
	Repaired significant damage to sections of our Gulf Coast and offshore pipeline facilities caused by Hurricanes Katrina and Rita
E & P.	Increased production volumes in each quarter of the year despite lower than planned annual production as a result of delays in bringing certain production online, delays in recovering lost volumes due to Hurricanes Katrina and Rita and higher than planned maintenance in certain onshore fields
	Entered into additional derivative contracts in 2006 to manage price risk on a substantial portion of our 2007 natural gas production
	Replaced our production primarily through our capital drilling program, achieving an overall drilling success rate of 98 percent
Marketing	Entered into agreements to assign, terminate or divest of a significant transportation contract and certain of our historical natural gas and power contracts
Other	Resolved various legal and contractual disputes, including a settlement of the pending shareholder and derivative actions, those related to our Brazilian power plants and other domestic legal matters
	Divested of a majority of our remaining power operations for total proceeds of approximately $0.9 billion, including our Macae power facility

What to Expect Going Forward. For 2007, we expect our current operating trends to continue. In our pipeline business, in February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission. We continue to lay the foundation for future growth by establishing an inventory of expansion projects in our primary growth areas and developing significant infrastructure opportunities. We anticipate that our remaining pipeline operations will continue to provide strong operating results based on the current levels of contracted capacity, continued success in re-contracting, expansion plans in our market and supply areas and the status of rate and regulatory actions. We recently announced that we will pursue the formation of a master limited partnership in 2007 to enhance the value and financial flexibility of our pipeline assets and provide a lower-cost source of capital for new projects.

In our exploration and production business, we will continue to seek to create value through a disciplined and balanced capital investment program, through active management of the increasing cost of production services, and efficiency improvements. In our drilling programs, we will focus on delivering reserves and volumes at reasonable finding and operating costs. Our future financial results will be primarily dependent on the continued successful execution of these drilling programs and commodity prices to the extent our anticipated natural gas and oil production is unhedged. We have hedged a substantial portion of our anticipated 2007 natural gas and oil production.

Update of Credit Metrics. In 2006, we strengthened our credit metrics as a result of several actions taken during the year including:

- Reducing debt by $2.8 billion, primarily through asset sales and issuing common stock;
- Restructuring our revolving credit facilities with improved terms;
- Receiving upgraded senior unsecured debt ratings to B2 with a positive outlook from Moody's and B with a positive outlook from Standard and Poor's; and
- Entering into contracts to eliminate the price risk on a portion of our historical Marketing natural gas book.

Our net debt (debt less cash) was $14.9 billion at December 31, 2006 (including $0.7 billion of ANR debt reported in discontinued operations). The closing of the ANR sale provides us with approximately $3.3 billion for additional debt reduction, and in February 2007, we launched an offer to tender for certain of our outstanding debt issues. Additional debt reductions will be based on the capital requirements of our pipeline and exploration and production businesses, our ability to generate strong cash flow from these businesses, completion of the sale of our remaining power assets and resolution of remaining historical issues. Our liquidity and capital resources discussions that follow provide further information on these events.

Results of Operations

Overview

As of December 31, 2006, our core operating business segments were Pipelines, Exploration and Production and Marketing. We also have a Power segment with interests in international power plants in Brazil, Asia and Central America. These 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 consolidated operations as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively 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 (loss) from continuing operations, such as extraordinary items, discontinued operations and the cumulative effect of accounting changes, (ii) income taxes, (iii) interest and debt expense (iv) distributions on preferred interests of consolidated subsidiaries and (v) preferred stock dividends. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries from this measure so that investors may evaluate our operating results independently from 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 flow.

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

	2006	2005	2004
		(In millions)	
Segment			
Pipelines	$ 1,187	$ 924	$ 1,059
Exploration and Production	640	696	734
Marketing	(71)	(837)	(539)
Power	82	(89)	(747)
Field Services	—	285	84
Segment EBIT	1,838	979	591
Corporate and other	(88)	(521)	(217)
Consolidated EBIT	1,750	458	374
Interest and debt expense	(1,228)	(1,286)	(1,497)
Distributions on preferred interests of consolidated subsidiaries	—	(9)	(25)
Income taxes	9	331	116
Income (loss) from continuing operations	531	(506)	(1,032)
Discontinued operations, net of income taxes	(56)	(96)	85
Cumulative effect of accounting changes, net of income taxes	—	(4)	—
Net income (loss)	$ 475	$ (606)	$ (947)

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.

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 power, coal and fuel oil. Our revenues from transportation, storage, LNG terminalling and related services consist of two types:

Type	Description	% of Total Revenues
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts.	79
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.	21

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 and market conditions, regulatory actions, competition, weather and the creditworthiness of our customers. We also experience earnings volatility when the amount of natural gas utilized in operations differs from the amounts we receive for that purpose.

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

We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although, at times, we discount these rates 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. We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2006. Below is the expiration schedule for firm transportation contracts executed as of December 31, 2006:

	BBtu/d	Percent of Total Available Capacity
2007	3,450	15
2008	2,628	11
2009	1,764	8
2010	3,339	14
2011	2,171	9
2012 and beyond	10,056	43

Summary of Operational and Financial Performance

In 2006, we continued to deliver excellent results with strong performance across all pipelines. We successfully resolved our EPNG rate case, restructured and renewed certain customer contracts, continued to place several expansion projects in service, including the Elba Island II terminal expansion and pipeline expansions in the Rockies, such as Cheyenne Plains, Piceance Basin, and Raton Basin, and made significant progress on several other growth projects. We have also benefited from (i) higher realized rates on certain of our systems, (ii) increased throughput in 2006, (iii) other various interruptible services, (iv) sales of gas not used in operations and (v) favorable impacts upon revaluation of gas imbalances. However, we continue to experience non-reimbursable hurricane related costs.

While actual throughput levels have a relatively minor impact on us since we generally sell capacity on our pipeline, the level of throughput can provide evidence of the underlying value of the capacity. In 2006, increased throughput across our system was a result of broad based increases in power demand from Mexico, California, the Northeast, and southeast based on underlying growth in electricity demand, a warmer summer, 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.

In 2007, we intend to build on the growth achieved in 2006. Among other projects currently underway, we are in the process of filing with the FERC several growth projects that will transport LNG from Georgia to Florida and the remainder of the southeastern United States. See a further discussion below.

Operating Results

	2006	2005	2004
	(In millions, except volume amounts)		
Operating revenues	$ 2,402	$ 2,171	$ 2,145
Operating expenses	(1,339)	(1,392)	(1,218)
Operating income	1,063	779	927
Other income	124	145	132
EBIT	$ 1,187	$ 924	$ 1,059
Throughput volumes (BBtu/d)[(1)]			
TGP	4,584	4,493	4,519
EPNG and MPC	4,255	4,214	4,235
CIG, WIC and CPG	4,301	3,734	2,808
SNG	2,167	1,984	2,163
Equity investments	1,705	1,645	1,698
Total throughput	17,012	16,070	15,423

(1) Volumes exclude intrasegment activities.

The table below and discussion that follows detail the impact on EBIT of significant events in 2006 compared with 2005 and 2005 as compared with 2004. We have also provided an outlook on events that may affect our operations in the future.

	2006 to 2005 Variance				2005 to 2004 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Higher reservation and services revenues	$128	$ —	$ —	$128	$ 24	$ —	$—	$ 24
Gas not used in operations, revaluations, processing revenues and other natural gas sales	20	38	—	58	(45)	8	—	(37)
Expansions	75	(9)	(10)	56	75	(28)	(2)	45
Hurricanes Katrina and Rita	—	(1)	—	(1)	(13)	(28)	—	(41)
Impairment of pipeline development projects	—	30	—	30	—	(46)	—	(46)
General and administrative expense	—	52	—	52	—	(42)	—	(42)
Higher depreciation expense	—	(19)	—	(19)	—	(2)	—	(2)
Higher pipeline integrity expense	—	(19)	—	(19)	—	—	—	—
Operating costs	—	(13)	—	(13)	—	(34)	—	(34)
Enron bankruptcy settlement	15	3	—	18	—	—	—	—
Sale of interest in gathering system	—	—	(11)	(11)	—	—	—	—
Other[(1)]	(7)	(9)	—	(16)	(15)	(2)	15	(2)
Total impact on EBIT	$231	$ 53	$(21)	$263	$ 26	$(174)	$13	$(135)

(1) Consists of individually insignificant items on several of our pipeline systems.

Higher Reservation and Other Services Revenues. During the year ended December 31, 2006, our reservation revenues increased primarily due to the termination, effective December 31, 2005, of reduced tariff rates to certain customers under the terms of EPNG's FERC-approved systemwide capacity allocation proceeding, an increase in EPNG's tariff rates which are subject to refund and which became effective on January 1, 2006, sales of additional firm capacity and higher realized rates on several of our pipeline systems compared to 2005. In addition, our usage revenues increased due to increased activity on our pipeline systems under various interruptible services provided under their tariffs as a result of favorable market conditions.

Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales. During 2006, higher realized prices on sales of gas not used in operations resulted in favorable impacts to our operating revenues, partially offset by lower sales volumes of natural gas during 2006 compared to 2005. We also experienced favorable impacts to our operating expenses in 2006 due to decreases in the index prices used to value the net imbalance position on several of our pipeline systems. In 2005, higher gas prices caused an increase in our obligation to replace system gas and settle gas imbalances in the future, resulting in an unfavorable impact on our operating results. In addition, our pipelines also retained lower volumes of gas not used in operations during 2005. We anticipate that the overall activity in this area will continue to vary based on factors such as regulatory actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors.

Expansions. Below is a discussion of (i) our FERC approved expansion projects placed in service and (ii) other FERC approved expansion projects not yet completed which we are in various stages of certification and approval.

Projects Placed in Service. During 2005 and 2006, we placed several significant expansion projects in service including Cheyenne Plains, the Elba Island LNG expansion, the Raton Basin project and the Piceance Basin project and related compression on our WIC system.

Projects Not Yet Completed.

Project	Anticipated Completion or In-Service Date	Estimated Cost	Estimated Future Revenues
Louisiana Deepwater Link	July 2007	$ 55 million(1)	(2)
Triple-T Extension	September 2007	$ 33 million(3)	(2)
Essex Middlesex Project	November 2007	$ 47 million	$1 million in 2007 $8 million annually thereafter
Northeast ConneXion — New England	November 2007	$103 million	$6 million in 2007 $37 million annually thereafter
Cypress Expansion(4)	May 2007	$321 million	$62 million annually

(1) Estimate reflects anticipated payment of approximately $15 million in contributions to a third party.
(2) Revenues for these projects will be based on throughput levels as natural gas reserves are developed.
(3) Amount shown is net of anticipated the receipt of approximately $12 million in contributions-in-aid-of construction.
(4) Project will consist of three phases. The anticipated completion date is related to phase 1.

Hurricanes Katrina and Rita. During 2006 and 2005, we recorded higher operation and maintenance expenses as a result of unreimbursed amounts expended to repair damage caused by Hurricanes Katrina and Rita in 2005. For a further discussion of the impact of these hurricanes on our capital expenditures, see Capital Resources and Liquidity below.

Impairment of Pipeline Development Projects. During 2006 and 2005, we impaired various pipeline development projects based on changing market conditions. In 2006, we recorded impairments of $13 million and $3 million due to discontinuing our Continental Connector Pipeline project and the remainder of our Seafarer Project. In 2005, we recorded impairments of $18 million and $28 million due to discontinuing a portion of our Seafarer project and the entirety of our Blue Atlantic development project.

General and Administrative Expenses. During the year ended December 31, 2006, our general and administrative costs were lower than 2005, primarily due to a decrease in accrued benefit costs and lower allocated costs from El Paso. During the year ended December 31, 2005, our general and administrative costs were higher than in 2004, primarily due to an increase in direct payroll related benefits for our employees, higher legal and insurance costs of, and higher corporate overhead allocations from El Paso. El Paso's allocation to us increased in 2005 based on the estimated level of resources devoted to our segment's operations and the relative size of our EBIT, gross property and payroll as compared to the consolidated totals.

Higher Depreciation Expense. Depreciation expense was higher for 2006 compared to 2005 primarily due to higher depreciation rates applied to EPNG's property, plant and equipment following the effective date of its rate case.

Pipeline Integrity Costs. As of January 1, 2006, we adopted an accounting release issued by the FERC that requires us to expense certain costs our interstate pipelines incur related to their pipeline integrity programs. Prior to adoption, we capitalized these costs as part of our property, plant and equipment.

Operating Costs. During 2006, we incurred higher costs primarily for repairs and maintenance. During 2005 and 2004, we incurred higher costs for compressor engine repair and preventive maintenance, lowering of lines and pipeline integrity testing as well as higher legal and environmental reserves.

Enron Bankruptcy Settlement. During 2006, we recorded income of approximately $18 million, net of amounts potentially owed to certain customers, associated with the receipt of settlement proceeds related to the Enron bankruptcy. We may receive additional amounts in the future as settlement proceeds are released by the bankruptcy court.

Regulatory Matters/Rate Cases. Our pipeline systems periodically file for changes in their rates, which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to positively or negatively impact our profitability. Currently, certain of our pipelines have no requirements to file new rate cases and expect to continue operating under their existing rates. However, certain other pipelines listed below are currently in rate proceedings or have upcoming rate actions.

- EPNG — EPNG negotiated a settlement of its rate case that was filed with the FERC in December 2006. The settlement provides benefits for both EPNG and its customers for a three-year period ending December 31, 2008. For a further discussion of this settlement, see Item 8, Financial Statements and Supplementary Data, Note 13.

- CIG — In August 2006, the FERC approved a settlement reached with CIG's customers effective October 1, 2006. The settlement establishes system-wide base rates through at least September 2010, but no later than September 2011, and establishes a sharing mechanism to encourage additional fuel savings. We anticipate an increase in revenues of approximately $6 million annually from the effective date of the settlement.

- MPC — MPC is required by its previous rate case settlement to file for new rates to be effective in March 2007. We anticipate a rate decrease resulting from a variety of factors, including a decline in the rate base and various changes in rate design since the last rate case although the amount of the impact is not yet determinable.

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves with the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. Our domestic natural gas and oil reserve portfolio blends slower decline rate, typically longer lived assets in our Onshore region with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico Shelf and south Louisiana regions. We believe the combination of our assets in these regions provides significant near-term cash flow while providing consistent opportunities for competitive investment returns. In addition, our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and longer term cash flows.

As part of our business strategy, we attempt to create value through our drilling activities and through acquisitions of assets and companies. For 2007, we expect our growth to occur principally through drilling activities. However, we believe strategic acquisitions can support our corporate objectives by:

- Re-shaping our portfolio to provide greater optionality for achieving our long term performance goals;
- Leveraging operational expertise we already possess in key operating areas, geologies or techniques;
- Balancing our exposure to regions, basins and commodities;
- Achieving risk-adjusted returns competitive with those available within our existing inventory; and
- Increasing our reserves more rapidly by supplementing our current drilling inventory.

In addition to executing on our strategy, the profitability and performance of our exploration and production operations can be substantially impacted by (i) changes in commodity prices, (ii) industry-wide increases in drilling and oilfield service costs, and (iii) the effect of hurricanes and other weather impacts on our daily production, operating, and capital costs. To the extent possible, we attempt to mitigate these factors. As part of our risk management activities we have entered into derivative contracts on a significant portion of our anticipated natural gas and oil production in 2007 to reduce the financial impact of downward commodity price movements. We are also actively managing increases in operating and capital costs.

Significant Operational Factors Affecting the Year Ended December 31, 2006

Production. Our average daily production for the year was 730 MMcfe/d (excluding 68 MMcfe/d from our equity investment in Four Star). Our production levels grew in every quarter of 2006. However, our average daily production was lower than originally expected primarily due to unexpected delays in our Gulf of Mexico Shelf and Onshore regions. Below is a further analysis of our 2006 production by region (MMcfe/d):

	2006	2005	2004
United States			
Onshore	345	300	231
Texas Gulf Coast[1]	187	211	283
Gulf of Mexico Shelf / south Louisiana	174	179	276
International			
Brazil[2]	24	53	24
Total Consolidated	730	743	814
Four Star [3]	68	24	—

(1) During 2006, we completed the sale of certain non-strategic south Texas properties with production of approximately 5 MMcfe/d. In January 2007, we acquired certain properties with net production on the acquisition date of approximately 12 MMcfe/d.
(2) Production volumes decreased due to a contractual reduction of our ownership interest in the Pescada-Arabaiana Field in 2006.
(3) Amounts represent our proportionate share of the production of Four Star which was acquired in the third quarter of 2005.

In our Onshore region, we increased our 2006 production through our drilling programs and our acquisition of Medicine Bow in 2005 despite the impact of higher maintenance activity and delivery delays for two rigs contracted in East Texas reducing our expected 2006 production. In the Texas Gulf Coast, we were able to stabilize 2006 production levels after a repositioning effort in the region in 2004. In the Gulf of Mexico Shelf/south Louisiana region, production in both 2005 and 2006 was adversely affected by Hurricanes Katrina and Rita in 2005 and construction delays on certain new wells in 2006. However, we were successful in developing projects in the West Cameron area and our Catapult project that helped offset natural declines. In Brazil, a contractual reduction of our ownership interest in the Pescada-Arabaiana fields in early 2006 resulted in a decrease in production.

2006 Drilling Results

Onshore. We drilled 604 successful gross wells out of 606 gross wells drilled.

Texas Gulf Coast. We experienced an 88 percent success rate on 49 gross wells drilled.

Gulf of Mexico Shelf and south Louisiana. We experienced a 82 percent success rate on 17 gross wells drilled. We placed 10 new wells in production, including five wells in south Louisiana, and five wells in the Gulf of Mexico. We expect an additional four wells drilled in 2007 to come on production in early 2007.

Brazil. In the Pinauna Field in the Camamu Basin, we filed a plan of development, signed a rig contract and began to drill two exploratory wells in February 2007. Additionally, in the ES-5 Block in the Espirito Santo Basin, we continue to discuss a possible exploration well with Petrobras.

Egypt. We were the winning bidder of the South Mariut Block for $3 million in the second quarter of 2006 and agreed to a $22 million firm working commitment over three years. The block is about 1.2 million acres and is located onshore in the western part of the Nile Delta. We expect to receive formal governmental approvals and sign the concession agreement during the first quarter of 2007.

Cash Operating Costs. We monitor cash operating costs to determine the amount of cash required to produce our natural gas and oil volumes. These costs are calculated on a per MMcfe basis and are calculated as total operating expenses less depreciation or depletion, and amortization expense, other non-cash expense items and the cost of products and services on our income statement. In 2006, cash operating costs increased to $1.86/MMcfe from $1.67/MMcfe in 2005. Our operating cost increases were primarily a result of inflation in the cost of fuel, power, and other services, increases in subsurface maintenance in certain Onshore fields and unrecoverable hurricane repair costs, among other items. We do not expect a significant amount of costs in this segment in 2007 related to Hurricanes Katrina and Rita.

Reserve Replacement Costs / Reserve Replacement Ratio. We calculate two primary metrics, (i) a reserve replacement ratio and (ii) a reserve replacement cost, to measure our ability to establish a long-term trend of adding reserves at a reasonable cost in our core asset areas. The reserve replacement ratio is an indicator of our ability to replenish annual production volumes and grow our reserves. It is important for us to economically find and develop new reserves that will more than offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves. In addition, we calculate a reserve replacement cost to assess the cost of adding reserves which is ultimately included in depreciation, depletion and amortization expense. We believe the ability to develop a competitive advantage over other natural gas and oil companies is dependent on adding reserves in our core asset areas at a lower cost than our competition. We calculate these ratios as follows:

$$\text{Reserve replacement ratio} \qquad \frac{\text{Sum of reserve additions}^{(1)}}{\text{Actual production for the corresponding period}}$$

$$\text{Reserve replacement cost / Mcfe} \qquad \frac{\text{Total oil and gas capital costs}^{(2)}}{\text{Sum of reserve additions}^{(1)}}$$

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(1) Reserve additions include proved reserves and reflect reserve revisions, extensions, discoveries, and other additions and acquisitions and do not include unproved reserve quantities or proved reserve additions attributable to investments accounted for using the equity method. Amounts are derived directly from the table presented in

Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

(2) Total oil and gas capital costs include the costs of development, exploration, and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

Both the reserve replacement ratio and reserve replacement cost per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

The exploration for and the acquisition and development of natural gas and oil reserves is inherently uncertain as further discussed in Part I, Item 1A, Risk Factors, Risks Related to our Business. One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped. At December 31, 2006, proved developed reserves represent approximately 71 percent of total proved reserves. Proved developed reserves will generally begin producing within the year they are added whereas proved undeveloped reserves generally require a major future expenditure.

The table below shows our reserve replacement costs and reserve replacement ratio for each of the years ended December 31:

	2006	2005	2004
	($ / Mcfe)		
Reserve replacement costs, including acquisitions	$4.17	$2.75	$21.85
Reserve replacement costs, excluding acquisitions	4.19	3.19	N/A(1)
	(% of Production)		
Reserve replacement ratio, including acquisitions	108%	195%	11%
Reserve replacement ratio, excluding acquisitions	107	93	(10)

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(1) Not meaningful in 2004 due to downward revisions in previous estimates of reserves.

In 2006, our reserve replacement costs increased primarily due to industry service cost inflation, mechanical problems incurred in executing our drilling program, downward revisions in previous estimates of reserves due to lower commodity prices at December 31, 2006, and international capital investments where proved reserves have yet to be recorded. In 2004, our reserve replacement costs were negatively impacted by downward revisions of previous estimates of our reserves. We typically cite reserve replacement costs in the context of a multi-year trend, in recognition of its limitation as a single year measure, but also to demonstrate consistency and stability, which are essential to our business model. For the three year period ending December 31, 2006 our average reserve replacement costs were $3.99/Mcfe including acquisitions and $5.20/Mcfe excluding acquisitions.

Capital Expenditures. Our capital expenditures were as follows for the three years ended December 31:

	2006	2005	2004
Total oil and gas capital costs[1]	$1,193	$1,462	$ 743
Less: acquisition capital	(4)	(651)	(102)
Capital expenditures, excluding acquisitions	$1,189	$ 811	$ 641

(1) Total oil and gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

Outlook for 2007

For 2007, we anticipate the following on a worldwide basis:

- Average daily production volumes for the year of approximately 740 MMcfe/d to 795 MMcfe/d, which excludes approximately 60 MMcfe/d to 65 MMcfe/d from our equity investment in Four Star. Our goal is to achieve between three and eight percent average annual production growth over the next several years.
- Capital expenditures, excluding acquisitions, between $1.4 billion and $1.5 billion, which represents a 20 percent increase over 2006. While 85% of the company's planned 2007 capital program is allocated to its domestic program, we plan to spend $215 million in international capital in 2007, primarily in our Brazil exploration and development program. In January 2007, we acquired producing properties and undeveloped acreage in Zapata County, Texas for $249 million which complement our existing Texas Gulf Coast operations and provide a re-entry into the Lobo trend. The assets acquired had net production of approximately 12 MMcfe/d on the acquisition date. Estimated proved reserves were approximately 84 Bcfe of which approximately 73 percent was undeveloped.
- Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.68/Mcfe to $2.00/Mcfe for the year; and
- Depreciation, depletion, and amortization rate of between $2.50/Mcfe and $2.75/Mcfe in the first quarter of 2007 compared with $2.58/Mcfe in the fourth quarter of 2006.

Price Risk Management Activities

As part of our strategy, we enter into derivative contracts on our natural gas and oil production to stabilize cash flows, to reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. Because this strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. Adjustments to our hedging strategy and the decision to enter into new positions or to alter existing positions are made at the corporate level based on the goals of the overall company. The following table and discussion that follows shows, as of December 31, 2006, the contracted volumes and the minimum, maximum and average prices we will receive under these contracts when combined with the sale of the underlying hedged production:

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)
	Volumes	Price	Volumes	Price	Volumes	Price	Volumes
Natural Gas							
2007	78	$ 7.70	55	$8.00	55	$16.89	110
2008	5	$ 3.42	—	—	—	—	—
2009	5	$ 3.56	—	—	—	—	—
2010-2012	11	$ 3.81	—	—	—	—	—
Oil							
2007	192	$35.15	—	—	—	—	—

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.
(2) Our basis swaps effectively "lock-in" locational price differences on a portion of our natural gas production in Texas and Oklahoma.

Our natural gas fixed price swap, floor and ceiling contracts in the table above are designated as accounting hedges. Gains and losses associated with these natural gas contracts are deferred in accumulated other comprehensive income and will be recognized in earnings upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. Our oil swaps and approximately 51 TBtu of our natural gas basis swaps are not designated as hedges. Accordingly, changes in the fair value of these swaps are not deferred, but are recognized in earnings each period.

The table above does not include (i) derivative contracts we terminated in the fourth quarter of 2006 on which we will record an additional $62 million of gains (before income taxes) in 2007 which are currently deferred in accumulated other comprehensive income or (ii) contracts entered into by our Marketing segment as further described on page 53. For the consolidated impact of the entirety of El Paso's production-related price risk management activities on our liquidity, see the discussion of factors that could impact our liquidity beginning on page 62.

Operating Results and Variance Analysis

The tables below and the discussion that follows provide the operating results and analysis of significant variances in these results during the periods ended December 31:

	2006	2005	2004
	(In millions, except for volumes and prices)		
Operating Revenues:			
Natural gas	$ 1,406	$ 1,420	$ 1,428
Oil, condensate and NGL	430	371	305
Other	18	(4)	2
Total operating revenues	1,854	1,787	1,735
Operating Expenses:			
Depreciation, depletion and amortization	(645)	(612)	(548)
Production costs(1)	(331)	(261)	(210)
Cost of products and services	(87)	(47)	(54)
General and administrative expenses	(156)	(185)	(173)
Other	(10)	(11)	(24)
Total operating expenses	(1,229)	(1,116)	(1,009)
Operating Income	625	671	726
Other Income(2)	15	25	8
EBIT	$ 640	$ 696	$ 734

	2006	Percent Variance	2005	Percent Variance	2004
Consolidated volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	220,402	(1)%	222,292	(9)%	244,857
Prices ($/cf)[3]					
Average realized prices including hedges	$ 6.38	—%	$ 6.39	10%	$ 5.83
Average realized prices excluding hedges	$ 6.64	(12)%	$ 7.53	28%	$ 5.90
Average transportation costs ($/Mcf)	$ 0.23	28%	$ 0.18	6%	$ 0.17
Oil, condensate and NGL					
Volumes (MBbls)	7,686	(6)%	8,136	(8)%	8,818
Prices ($/Bbl)[3]					
Average realized prices including hedges	$ 55.90	23%	$ 45.60	32%	$ 34.61
Average realized prices excluding hedges	$ 56.21	21%	$ 46.43	34%	$ 34.75
Average transportation costs ($/Bbl)	$ 0.82	30%	$ 0.63	(44)%	$ 1.12
Total equivalent volumes					
MMcfe	266,518	(2)%	271,107	(9)%	297,766
MMcfe/d	730	(2)%	743	(9)%	814
Production costs and other cash operating costs ($/Mcfe)					
Average lease operating cost	$ 0.95	32%	$ 0.72	20%	$ 0.60
Average production taxes	0.29	21%	0.24	118%	0.11
Total production cost[1]	$ 1.24	29%	$ 0.96	35%	$ 0.71
Average general and administrative cost	$ 0.59	(13)%	$ 0.68	17%	$ 0.58
Average taxes, other than production and income taxes	$ 0.03	—%	$ 0.03	—%	$ —
Total cash operating costs[4]	$ 1.86	11%	$ 1.67	29%	$ 1.29
Unit of production depletion cost ($/Mcfe)	$ 2.29	9%	$ 2.10	24%	$ 1.69
Unconsolidated affiliate volumes (Four Star)[2]					
Natural gas (MMcf)	18,140		6,689		
Oil, condensate and NGL (MBbls)	1,087		359		
Total equivalent volumes					
MMcfe	24,663		8,844		
MMcfe/d	68		24		

(1) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).
(2) Includes equity earnings from our investment or our proportionate share of volumes in Four Star acquired in the third quarter 2005.
(3) Prices are stated before transportation costs.
(4) See further discussion on page 44.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Our EBIT for 2006 decreased $56 million as compared to 2005. The table below lists the significant variances in our operating results in 2006 as compared to 2005:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Lower realized prices in 2006	$(197)	$ —	$ —	$(197)
Impact of hedges	197	—	—	197
Lower production volumes in 2006	(14)	—	—	(14)
Oil, Condensate and NGL Revenue				
Higher realized prices in 2006	75	—	—	75
Impact of hedges	5	—	—	5
Lower volumes in 2006	(21)	—	—	(21)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2006	—	(51)	—	(51)
Lower production volumes in 2006	—	10	—	10
Production Costs				
Higher lease operating costs in 2006	—	(58)	—	(58)
Higher production taxes in 2006	—	(12)	—	(12)
General and Administrative Expenses	—	29	—	29
Other				
Change in fair value of oil and basis swaps	(31)	—	—	(31)
Earnings from investment in Four Star	—	—	(9)	(9)
Processing plants	41	(29)	—	12
Other	12	(2)	(1)	9
Total Variances	$ 67	$(113)	$(10)	$ (56)

Operating revenues. Natural gas revenues decreased by approximately $197 million as natural gas prices were not as strong in 2006 as compared to 2005. However, we experienced lower hedging program losses for 2006 of $58 million compared to losses of $260 million for 2005. Realized oil, condensate and NGL prices increased in 2006 when compared to 2005.

Our production volumes have benefited from our acquisitions in 2005. However, overall production volumes have decreased in our Texas Gulf Coast and Gulf of Mexico Shelf and south Louisiana regions due to natural declines, and the sale of certain non-strategic south Texas properties with average production of 5 MMcfe/d in 2006. Also, our Gulf of Mexico Shelf and south Louisiana region production continued to be impacted in 2006 by Hurricanes Katrina and Rita, which occurred in late 2005. Our production volumes in Brazil decreased due to the contractual reduction of our ownership interest in the Pescada-Arabaiana Field in 2006.

Depreciation, depletion and amortization expense. During 2006, we experienced higher depletion rates as compared to 2005 primarily as a result of higher finding and development costs and the cost of acquired reserves. However, lower production volumes in 2006 partially offset the impact of these higher depletion rates.

Production costs. In 2006, our lease operating costs increased as compared to 2005 in all regions as a result of inflation in fuel costs, power and other services. In our Onshore region, additional increases were due to increased subsurface maintenance and our acquisition of Medicine Bow. In the Gulf of Mexico Shelf region, additional increases were due to hurricane repairs not recoverable through insurance. Additionally, production taxes increased as a result of lower tax credits in Texas taken in 2006 compared to 2005.

General and administrative expenses. Our general and administrative expenses decreased during 2006 as compared to the same periods in 2005, primarily due to lower corporate overhead allocations.

Other. During 2006, we recorded a loss of approximately $40 million of the fair value of our derivatives not designated as hedges as compared to a $9 million loss in 2005. In 2006, our EBIT was also unfavorably impacted by earnings from Four Star due to lower natural gas prices. Our EBIT was favorably impacted by operations at our processing plants and insurance recoveries resulting from Hurricane Ivan, among other items.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Our EBIT for 2005 decreased $38 million as compared to 2004. The table below lists the significant variances in our operating results in 2005 as compared to 2004:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 362	$ —	$—	$ 362
Lower volumes in 2005	(133)	—	—	(133)
Impact of hedges	(237)	—	—	(237)
Oil, Condensate and NGL Revenue				
Higher realized prices in 2005	95	—	—	95
Lower volumes in 2005	(24)	—	—	(24)
Impact of hedges	(5)	—	—	(5)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2005	—	(110)	—	(110)
Lower production volumes in 2005	—	45	—	45
Production Costs				
Higher lease operating costs in 2005	—	(17)	—	(17)
Higher production taxes in 2005	—	(34)	—	(34)
General and Administrative Expenses	—	(12)	—	(12)
Other				
Earnings from investment in Four Star	—	—	19	19
Other	(6)	21	(2)	13
Total Variances	$ 52	$(107)	$17	$ (38)

Operating revenues. During 2005, we benefited from a strong commodity pricing environment for natural gas and oil, condensate and NGL. However, losses in our hedging program for the year ended December 31, 2005 were $260 million compared to $18 million in 2004. Additionally, we experienced a nine percent decrease in production volumes versus the same period in 2004. Although our production volumes benefited from the acquisitions in 2005 and our acquisition and consolidation of the remaining interest in UnoPaso in Brazil in July 2004, our Texas Gulf Coast and Gulf of Mexico Shelf and south Louisiana regions experienced declines in year over year production due to normal declines and a lower capital spending program in these areas over the last several years. In addition, the Gulf of Mexico Shelf and south Louisiana region was impacted by Hurricanes Katrina and Rita, while the Texas Gulf Coast region was impacted by mechanical well failures.

Depreciation, depletion and amortization expense. During 2005, we experienced higher depletion rates compared to 2004 as a result of higher finding and development costs and the cost of acquired reserves resulting in higher depreciation, depletion and amortization expense. However, during 2005, the impact of lower production volumes partially offset the impact of our higher depletion rates.

Production costs. We experienced higher costs in 2005 due to the implementation of programs in the first half of 2005 to improve production in the Texas Gulf Coast and Gulf of Mexico Shelf and south Louisiana regions, higher salt water disposal costs, utility expenses, marine transportation costs and increased operating costs in Brazil due to our July 2004 UnoPaso acquisition and consolidation. Production taxes were also higher as the result of higher commodity prices in 2005 and higher tax credits taken in 2004 on high cost natural gas wells.

General and administrative expenses. Our general and administrative expenses were higher in 2005 than in 2004, primarily due to an increase in direct payroll related benefits for our employees, and higher legal and insurance costs.

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 risks, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate remaining natural gas supply, transportation, power and other natural gas contracts entered into prior to the deterioration of the energy trading environment in 2002. Any future liquidations may impact our cash flows and financial results. However, we may not liquidate certain of these remaining historical contracts before their expiration if (i) they are uneconomical to sell or terminate in the current environment due to their terms, credit concerns of the counterparty or lack of liquidity in the market or (ii) a sale would require an acceleration of cash demands. The table that follows provides a summary of these events, our remaining contracts and their sensitivity to changes in commodity prices.

Contract Type	Description	Significant Events/Remaining Exposure	Expected Earnings Volatility
Mark-to-Market			
Production-related natural gas and oil derivatives	Option contracts with various floor and ceiling prices	Terminated our 2007 natural gas collars and replaced them with natural gas puts in November 2006. Our collars significantly impacted our results in 2006 due to changes in natural gas prices and our new puts may have an impact in the future if volatility continues.	High
Power contracts	Pennsylvania-New Jersey-Maryland (PJM) basis and installed capacity positions.	Impacted by changes in regional power prices in 2006 and may have an impact in the future if volatility continues.	Moderate
	PJM commodity contracts.	Remaining commodity positions are hedged at PJM west hub.	Low
Other natural gas contracts	Fixed-price, physical delivery contracts; fixed-for-float swaps.	Sold, terminated or entered into offsetting derivative transactions in 2006 to substantially eliminate the price risk associated with a significant number of contracts, which reduces our future earnings exposure to changes in natural gas prices.	Low
Accrual			
Transportation-related natural gas contracts	Pipeline capacity contracts.	Released or assigned capacity related to Alliance, TGP and a pipeline serving California, which should significantly reduce our exposure to future losses.	Low
Long-term gas supply obligations	Primarily ten contracts with delivery obligations up to 0.7 Bcf/d with expiration dates ranging from 2008 to 2028.	The majority of our supply contracts are index-priced.	Low

Operating Results

Overview. Over the past three years, our operating results and year-to-year comparability were significantly impacted by substantial commodity price fluctuations and changes in the composition of our portfolio based on actions taken to reduce our exposure to these commodity price fluctuations and to exit historical trading activities. In 2004 and 2005, rising natural gas prices had a significant negative impact on our natural gas and power derivative contracts resulting in significant losses in those years. During the past two years, we entered into transactions to reduce our exposure to commodity prices, including the divestitures of our Cordova tolling agreement and a majority of the contracts in our power portfolio in 2005, and the divestiture of a significant portion of our natural gas portfolio in 2006. In 2006, we also recorded losses of $188 million upon paying a third party to assume our Alliance transportation capacity obligations effective November 1, 2007, and approximately $133 million in the third quarter of 2006 on our Midland Cogeneration Venture (MCV) supply agreement in conjunction with the sale of our interest in the related power facility. The combination of actions taken to reduce our exposure and decreases in natural gas prices improved our operating results in 2006. The tables below and discussions that follow provide further information about of these events, our overall operating results and analysis by significant contract type for our Marketing segment during each of the three years ended December 31:

	2006	2005	2004
		(In millions)	
Gross Margin by Significant Contract Type:			
Production-Related Natural Gas and Oil Contracts			
Changes in fair value of options and swaps	$ 269	$(436)	$ 53
Changes in fair value of other production-related derivatives	—	—	(439)
Gross margin	269	(436)	(386)
Contracts Related to Historical Trading Operations:			
Natural gas transportation-related natural gas contracts:			
Demand charges	(125)	(156)	(151)
Settlements and termination payments[(1)]	(110)	121	87
Changes in fair value of other natural gas derivative contracts[(2)]	(163)	39	44
Changes in fair value of power contracts	71	(386)	(121)
Other	—	22	19
Gross margin[(3)]	(327)	(360)	(122)
Total gross margin	(58)	(796)	(508)
Operating expenses[(4)]	(33)	(59)	(54)
Operating loss	(91)	(855)	(562)
Other income, net	20	18	23
EBIT	$ (71)	$(837)	$(539)

(1) Amount for 2006 includes a $188 million loss in operating revenues related to Alliance further discussed below and a $50 million gain in 2004 related to early termination of an LNG contract.

(2) Amounts for 2006 include the loss on our MCV contract described above.

(3) Gross margin consists of revenues from commodity trading and origination activities less costs of commodities sold, including changes in the fair value of derivative contracts.

(4) In 2006 and 2005, we incurred lower corporate overhead allocation and general and administrative expenses based on overall cost reduction efforts at the corporate level and our reduced level of operations. In 2005, we recorded $19 million of legal settlements and reserves, which resulted in increased operating expenses during 2005.

Production-related Natural Gas and Oil Derivatives

Options and swaps. Our production-related natural gas and oil derivative contracts are designed to provide protection to El Paso against changes in natural gas and oil prices in addition to those derivative contracts entered into by our Exploration and Production segment which are further discussed beginning on page 40. For the consolidated impact of all of El Paso's production-related price risk management activities, refer to our liquidity discussion beginning on page 52.

As of December 31, 2006, our production-related derivatives consisted of various option contracts as all of our swap contracts had expired. The fair value of our derivative contracts is impacted by changes in commodity prices from period-to-period and is marked-to-market in our results. Listed below are the volumes and average prices associated with our production-related derivative contracts as of December 31, 2006:

	Floors[1]		Ceilings[1]	
	Volumes	Average Price	Volumes	Average Price
Natural Gas				
2007	89	$ 7.50	—	$ —
2008	18	$ 6.00	18	$10.00
2009	17	$ 6.00	17	$ 8.75
Oil				
2007	1,009	$55.00	1,009	$60.38
2008	930	$55.00	930	$57.03

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

During 2006, decreases in commodity prices favorably impacted the value of our contracts and our EBIT and in 2005, increases in commodity prices negatively impacted the value of our contracts and our EBIT. We received approximately $59 million in 2006 and paid $40 million in 2005 related to contracts that settled during those periods.

During the fourth quarter of 2006, we entered into put contracts on 89 TBtu of natural gas production in 2007 at a floor price of $7.50 per MMbtu for which we paid a premium of $82 million. The premium paid was largely offset by funds received by our Exploration and Production segment during 2006 upon the termination of 75 TBtu of collars on 2007 natural gas production. If natural gas and oil prices remain above the floor prices of our option contracts, our option contracts will expire without any value and we will expense the premium paid. If natural gas and oil prices increase above the ceiling prices of our option contracts, losses will occur since we are obligated under these contracts to provide natural gas and oil at fixed prices that are lower than the market price.

Other production-related derivatives. In 2004, our losses were a result of increases in natural gas prices relative to fixed priced commodity contracts held at the time. In the fourth quarter of 2004, we designated those contracts as accounting hedges and transferred them to our Exploration and Production segment which reflects those contracts in its financial results.

Contracts Related to Historical Trading Operations

Natural gas transportation-related contracts. As of December 31, 2006, our transportation contracts provide us with approximately 0.8 Bcf/d of pipeline capacity that require us to pay approximately $115 million in demand charges in 2007. In December 2006, we paid a third party $188 million to assume our obligations under our Alliance capacity contract beginning November 1, 2007, which will reduce our demand charges to an average of approximately $46 million annually from 2008 to 2011. The recovery of demand charges related to our transportation contracts and therefore the profitability of these contracts, is dependent upon our ability to use or remarket the contracted pipeline capacity, which is impacted by a number of factors including differences in natural gas prices at contractual receipt and delivery locations, the working capital needed to use this capacity and the capacity required to meet our other long term obligations. These transportation contracts are accounted for on an accrual basis and impact our gross margin as delivery or service under the contracts occurs. The following table is a summary of our demand charges (in millions) and our percentage of recovery of these charges for each of the three years ended December 31:

	2006	2005	2004
Alliance:			
Demand charges[(1)]	$64	$65	$61
Recovery	59%	93%	72%
Enterprise Texas:			
Demand charges	$12	$26	$27
Recovery	—%[(2)]	8%	2%
Other:			
Demand charges[(3)]	$49	$65	$63
Recovery	92%	94%	38%

(1) In 2006, excluded from this amount is the $188 million we paid in conjunction with the sale of this contract described above.
(2) In 2006, we were unable to recover demand charges and incurred $4 million of losses in excess of the demand charges related to managing the capacity under these contracts.
(3) Includes demand charges related to storage contracts of $1 million, $1 million and $2 million in 2006, 2005, and 2004.

Other natural gas derivative contracts. In addition to our transportation-related natural gas contracts, we have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices. Our exposure to the volatility of gas prices as it relates to our other natural gas derivative contracts varies from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Because we had the right to purchase more natural gas at fixed prices than we had the obligation to sell under these contracts and because natural gas prices increased during 2004, and 2005, the fair value of these contracts increased. However, natural gas prices decreased during 2006 resulting in a decrease in fair value of these contracts. As noted above, during 2006, we divested or entered into transactions to divest of a substantial portion of these natural gas contracts, which substantially eliminated our future cash and earnings exposure to price movements on these contracts.

Our EBIT during 2006 also was impacted by a $49 million gain associated with the assignment of contracts to supply natural gas to certain municipalities in Florida and a mark-to-market loss in the third quarter of approximately $133 million on natural gas supply contracts associated with the sale by our Power segment of its interest in the MCV power plant. Prior to the sale, we had not recognized the cumulative mark-to-market losses on these contracts to the extent of our ownership interest due to their affiliated nature.

Power Contracts. By the end of 2005, we had divested or entered into transactions to divest of a substantial portion of our power contracts, including our Cordova tolling agreement, which substantially eliminated our cash and earnings exposure to power price movements on these contracts. Prior to entering into these transactions to eliminate the price risk associated with our historical positions, we experienced significant net decreases in the fair value of these contracts based primarily on changes in natural gas and power prices as well as differences in locational power prices.

Our remaining exposure in our power portfolio is related to four contracts that require us to swap locational differences in power prices between several power plants in the Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub, and provide installed capacity in the PJM power pool. We do not have commodity risk associated with these contracts due to positions we put in place in 2005 and 2006 to eliminate that risk. During 2006, the fair value of these contracts increased as the locational difference in power prices between the PJM east and west regions decreased.

Other. During 2005, a bankruptcy court entered an order allowing Mohawk River Funding III's (MRF III) bankruptcy claims with USGen New England. We received payment on these claims and recognized a gain of $17 million in 2005 related to this settlement. During 2004, we recorded a $25 million gain related to the termination of a power contract with our Power segment, which was eliminated in El Paso's consolidated results.

Power Segment

Overview. Our Power segment consists of assets in Brazil, Asia and Central America. We continue to pursue the sales of our remaining power investments, including our interest in the Porto Velho facility in Brazil. As of December 31, 2006, our remaining investment, guarantees and letters of credit related to power projects in this segment totaled approximately $660 million, which consisted of approximately $618 million in equity investments and notes receivable and approximately $42 million in financial guarantees and letters of credit.

Prior to 2006, our financial results in this segment were significantly impacted by impairment losses, net of gains (losses) on the sales of our domestic restructured power contracts and power facilities. In 2004, we recorded significant impairment charges based on our decision to exit our domestic and international power operations including approximately $590 million related to restructured power contracts and domestic power facilities and approximately $365 million related to our international power facilities. In 2005, we recorded additional impairments, net of gains and losses on sale, related to our Asian and Central American power facilities as well as losses on MCV. A further discussion of these events and other factors impacting our results in this segment for the three years ended December 31 are listed below:

	2006	2005	2004
		(In millions)	
EBIT by Area:			
Brazil			
Impairment of Manaus and Rio Negro	$ —	$ —	$(183)
EBIT from operations	64	55	64
Other International Power			
Impairments related to anticipated sales	(13)	(176)	(182)
Gain on sale of KIECO, PPN and Chinese plants	1	131	—
EBIT from operations[(1)]	(1)	34	64
Domestic Power			
Impairments, net of gains (losses) on sales	10	(167)	(590)
Favorable resolution of bankruptcy claim	—	53	—
EBIT from operations	—	—	133
Gain on sale of available-for-sale investment [(2)]	47	40	—
Other[(3)]	(26)	(59)	(53)
EBIT	$ 82	$ (89)	$(747)

(1) EBIT from operations includes a $17 million dividend on investment fund recorded in 2005.
(2) With the disposition of our shares in 2005 and 2006, we no longer have an interest in International Commodity Exchange.
(3) Other consists of indirect expenses and general and administrative costs. Also includes impairments and losses on the sales of power turbines of $27 million and $1 million recorded in 2005 and 2004.

Brazil. As of December 31, 2006, our remaining investment, guarantees and letters of credit related to power projects in Brazil were approximately $555 million. Of this amount, approximately $315 million relates to our Porto Velho project that sells power to Eletronorte under two power sales agreements that expire in 2010 and 2023. Eletronorte has expressed an interest in acquiring our interest in this power plant. As we evaluate this potential opportunity, we could be required to record a loss based on the potential value we may receive if we sell the facility. During 2006, 2005, and 2004, EBIT from our Porto Velho operations was $41 million, $23 million, and $28 million.

The remainder of our exposure in Brazil relates primarily to our Manaus and Rio Negro power plants, and our interests in the Bolivia-to-Brazil and Argentina-to-Chile pipelines (see further description in Part I, Item 1, Business, and Part II, Item 8, Financial Statements and Supplementary data, Note 18). In 2004, based on new power contracts that were signed in January 2005, we impaired our Manaus and Rio Negro facilities. These new contracts resulted in a decrease in earnings from these projects and, in addition, provide for the transfer of these facilities to the power off-taker in early 2008. The Manaus and Rio Negro plants had earnings from plant operations in 2006, 2005, and 2004 of $17 million, $19 million and $30 million. Our other Brazilian operations (including our interests in the Bolivia-to-Brazil and Argentina-to-Chile pipelines) generated EBIT of $6 million, $13 million, and $6 million in 2006, 2005 and 2004.

Other International Power. As of December 31, 2006, we had remaining investments, guarantees and letters of credit of approximately $105 million related to power projects in Asia and Central America. We expect to complete the sale of substantially all of these remaining international power assets during the first half of 2007, but any changes in regional political and economic conditions could negatively impact the anticipated proceeds, which could result in additional impairments. As noted above, we recorded impairments and gains on sales during 2004 and 2005 based on the value received or expected to be received upon closing the sales of our Asian and Central American assets. Our results during this period were also negatively impacted by the reduction in earnings as each facility was sold and by our decision to not recognize earnings from certain of our Asian and Central American assets based on our inability to realize those earnings through their expected selling price. We did not recognize earnings of approximately $26 million and $30 million for the years ended 2006 and 2005.

Domestic Power. Upon closing the sales of the MCV, Capitol District Energy Center Cogeneration Association(CDECCA) and Berkshire facilities in 2006, we completed the disposition of our domestic power business which we began in 2003. We recorded a gain of approximately $13 million upon the sale of MCV and recorded a $3 million loss on the sale of our CDECCA and Berkshire facilities. The disposition of our MCV facility in 2006 also impacted certain contracts and the financial results in our Marketing segment. As noted above, during 2004 and 2005 we sold our interests in several domestic power facilities and restructured power contracts, resulting in significant impairments and substantially lower earnings from these operations. In addition, we recorded impairments on our investment in MCV in 2004 based on a decline in its value due to increased fuel costs and recorded our proportionate share of MCV's losses based on their impairment of the plant assets in 2005.

Field Services Segment

During 2004 and 2005, the divestiture of the assets and operations of this segment resulted in significant gains and losses in our operating results. Prior to sale of these assets, we generated earnings primarily from our general and limited partner interests in GulfTerra and Enterprise Products Partners and from gathering and processing assets in south Texas and south Louisiana. The sales of these assets are further described in Part II, Item 8, Financial Statements and Supplementary Data, Note 18. The tables below and discussion that follows provide the operating results and additional analysis of significant factors affecting EBIT for our Field Services segment for each of the years ended December 31:

	2005	2004
	(In millions)	
Gathering and processing gross margins[1]	$ 25	$ 93
Operating expenses		
Loss on long-lived assets	(10)	(507)
Other operating expenses	(31)	(87)
Operating loss	(16)	(501)
Earnings from unconsolidated affiliates	301	618
Other expense	—	(33)
EBIT	$285	$ 84

	2005	2004
	(In millions)	
Gathering and Processing Activities		
Gathering and processing margins	$ 25	$ 93
Operating expenses	(8)	(87)
Other income	7	11
EBIT	24	17
GulfTerra/Enterprise-related Items		
Assets/interests sold to Gulf Terra and Enterprise		
Sale of GP/LP interests	183	507
Goodwill impairment	—	(480)
Other	4	(47)
Equity earnings	—	100
EBIT	187	80
Other Asset Sales		
Sale of Javelina investment	111	—
Other	(37)	(13)
	74	(13)
EBIT	$285	$ 84

(1) Gross margins consist of operating revenues less cost of products sold. We believe that this measurement is more meaningful for understanding and analyzing our Field Services segment's operating results in 2005 and 2004 because commodity costs historically were a significant factor in the determination of profit from our midstream activities.

Gathering and Processing Activities. The decreases in our gross margin in 2005 and in operation and maintenance expenses were primarily a result of asset sales, including the sales of our south Texas, north and south Louisiana, mid-continent and Indian Springs gathering and processing plants.

GulfTerra/Enterprise Related Items. Prior to 2006, we sold a number of assets to GulfTerra. While these sales decreased our gross margin and operating expenses, they increased the equity earnings from our general and limited partner interests in GulfTerra. However, over time, our overall equity earnings in GulfTerra declined as we sold our interests in that investment. The effect of significant transactions related to GulfTerra during 2005 and 2004 were as follows:

- Gain of $507 million upon the sale of our remaining 50 percent interest in the general partner of GulfTerra to Enterprise in 2004. As a result of this sale, we also impaired goodwill recorded on the segment; and
- Gain of $183 million on the sale of our remaining general partner and limited partner interests in Enterprise in 2005.

Corporate and Other Expenses, Net

Our corporate activities include our general and administrative functions as well as a number of miscellaneous businesses, which do not qualify as operating segments and are not material to our current year results. The following is a summary of significant items impacting the EBIT in our corporate operations for each of the three years ended December 31:

	2006	2005	2004
		(In millions)	
Change in litigation, insurance and other reserves	$(65)	$(418)	$ (81)
Western Energy Settlement	—	(72)	(38)
Restructuring charges	—	(27)	(91)
Debt related gains (losses):			
Foreign currency fluctuations on Euro-denominated debt	(20)	36	(26)
Early extinguishment/exchange of debt	(26)	(29)	(18)
Other	23	(11)	37
Total EBIT	$(88)	$(521)	$(217)

Litigation, Insurance, and Other Reserves. We have a number of pending litigation matters against us. In all of these matters, we evaluate each lawsuit and claim as to its merits and our defenses. Adverse rulings or unfavorable settlements against us related to these matters have impacted and may further impact our future results. In 2005 and 2004, we recorded significant charges in operation and maintenance expense to increase our litigation, insurance and other reserves based on ongoing assessments, developments and evaluations of the possible outcomes of these matters. In 2005, the most significant item was a charge in connection with a ruling by an appellate court that we indemnify a former subsidiary for certain payments being made under a retiree benefit plan. Additionally, we incurred charges in 2005 with the final prepayment of the Western Energy Settlement and charges related to increased premiums from a mutual insurance company in which we participate, based primarily on the impact of several hurricanes in 2004 and 2005. In 2004, we also incurred charges associated with the Western Energy Settlement obligation and charges related to our decision to withdraw from another mutual insurance company in which we were a member.

Restructuring Charges. As further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 13, we consolidated our Houston-based operations into one location and during 2005 and 2004 recorded charges of $27 million and $80 million related to vacating the remaining leased space and signing a termination agreement on the lease.

Interest and Debt Expense

	Years Ended December 31,		
	2006	2005	2004
		(In millions)	
Long-term debt, including current maturities	$1,193	$1,249	$1,419
Other interest	35	37	78
Total interest and debt expense	$1,228	$1,286	$1,497

Our total interest and debt expense has decreased over the past three years primarily due to the retirements of debt and other financing obligations, net of issuances. See Part II, Item 8, Financial Statements and Supplementary Data, Note 12, for a further discussion.

Income Taxes

	Years Ended December 31,		
	2006	2005	2004
		(In millions)	
Income taxes from continuing operations	$(9)	$(331)	$(116)
Effective tax rate	(2)%	40%	10%

In 2006 and 2005, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to recording $159 million and $58 million of tax benefits based primarily on the conclusion of IRS audits. In 2006, the audits of The Coastal Corporation's 1998-2000 tax years and El Paso's 2001 and 2002 tax years were concluded which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. In 2005, we finalized The Coastal Corporation's IRS tax audits for years prior to 1998.

In 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to sales of GulfTerra investment and impairments of certain of our foreign investments. The sale of GulfTerra resulted in a significant net taxable gain (compared to a lower book gain) and thus significant tax expense due to the non-deductibility of goodwill written off as a result of that transaction. Additionally, we received no U.S federal income tax benefit on the impairment of certain of our foreign investments.

For a discussion of our effective tax rates and other tax matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 5.

Discontinued Operations

Our discontinued operations include our ANR pipeline and related assets, our gathering and processing operations in south Louisiana, certain international power operations, petroleum markets operations and international natural gas and oil production operations outside of Brazil and Egypt. For the years ended December 31, 2006 and 2005, we had losses from our discontinued operations of $56 million and $96 million. Our 2006 loss of $56 million was primarily a result of recording approximately $188 million of deferred taxes upon agreeing to sell the stock of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission. Prior to our decision to sell, we were only required to record deferred taxes on individual assets and liabilities and a portion of our investment in the stock of one of these companies. In February 2007, we sold these assets and expect to recognize an after-tax gain of approximately $0.7 billion in the first quarter of 2007.

Our 2005 loss of $96 million was primarily a result of impairments of our discontinued international power operations partially offset by income from ANR and related assets and a gain on the sale of our south Louisiana operations. The impairments of our international power assets and the gain on the sale of south Louisiana are further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 2.

Our 2004 income from discontinued operations of $85 million was related primarily to operations of ANR and related assets and international power partially offset by other operational costs.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8, Financial Statements and Supplementary Data, Note 13.

Capital Resources and Liquidity

Debt Obligations. During 2006, we continued to reduce our overall debt obligations using cash on hand, cash generated from operations, proceeds from asset sales and proceeds from the issuance of common stock. We also restructured our $3 billion credit agreement. These actions have allowed us to reduce our debt obligations to $14.7 billion (excluding discontinued operations) as of December 31, 2006. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission to TransCanada and TC Pipelines, LP for approximately $4.1 billion, including the assumption of approximately $475 million of debt assumed by the buyer. The sale of ANR provides approximately $3.3 billion for additional debt reductions. Following the completion of the sale, we offered to tender certain of our outstanding debt. For a further discussion of our debt obligations, see Part II, Item 8, Financial Statements and Supplementary Data, Note 12.

Available Liquidity. As of December 31, 2006, we had available liquidity as follows (in billions):

Available cash	$0.4
Available capacity under our credit agreements	1.0
Net available liquidity at December 31, 2006	$1.4

Over the past few years, we have simplified our capital structure and our businesses and reduced the amount of liquidity needed for the normal course of business. However, we could be required to increase our available liquidity based on certain factors described below.

Expected 2007 Cash Flows. As noted above, we will repay a significant amount of debt using the proceeds from the sale of ANR. We also expect to generate positive operating cash flows in 2007 which, when supplemented with expected proceeds from other remaining asset sales will be used for working capital requirements and to grow and maintain our businesses through capital expenditures. We currently anticipate the following capital spending (in billions):

	Pipelines	Exploration and Production(1)	Total
Maintenance	$0.4	$1.2	$1.6
Growth	0.6	0.5	1.1
	$1.0	$1.7	$2.7

(1) Includes approximately $250 million spent in January 2007 for the acquisition of natural gas and oil properties.

As of December 31, 2006, our 2007 contractual debt maturities were approximately $0.8 billion. In the first half of 2007, we also have approximately $0.6 billion of debt that the holders can require us to redeem. Subsequent to year end, the holders of $300 million of these obligations did not exercise their redemption right and this debt will mature in 2027. Additionally, we have offered to tender certain of our debt obligations. To the extent necessary, we may also use cash on hand, cash flow generated from our operations, borrowings under our revolvers or new financing transactions for additional debt retirement.

Significant Factors That Could Impact Our Liquidity.

Cash Margining Requirements on Derivative Contracts. Historically we have been required to post significant cash margin deposits and letters of credit with the counterparties for the value of a substantial portion of our natural gas fixed price swap contracts that were at prices below current market prices. During 2006, approximately $0.9 billion of posted cash margin deposits were returned to us resulting from a combination of decreases in commodity prices and settlement of certain of these contracts and assignment of contracts in our power portfolio. As a result, a substantial portion of our remaining margin consists of letters of credit. In 2007, based on current prices, we expect approximately $0.2 billion of the total of $1.1 billion in collateral outstanding at December 31, 2006 to be returned to us in the form of both cash margin deposits and letters of credit.

If commodity prices increase, we could be required to post additional margin, and if prices decrease, we will be entitled to recover some of this amount earlier than anticipated. Based on our derivative positions at December 31, 2006, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements of approximately $11 million, which consists of $3 million for transactions that settle in 2007, $5 million for transactions that settle in 2008 and $3 million for transactions that settle in 2009 and thereafter. To mitigate any potential margin requirements should natural gas prices increase to a level greater than we currently anticipate, we entered into a $250 million unsecured contingent letter of credit facility in January 2007 that matures in March 2008 under which letters of credit are available to us if the average NYMEX gas price strip for the remaining calendar months through March 2008 reaches $11.75 per MMBtu.

Hurricanes. We continue to repair damages to our pipeline, exploration and production, and other related facilities caused by Hurricanes Katrina and Rita in 2005. We currently estimate the total repair costs will be approximately $625 million. Our mutual insurance company has indicated that we will not receive insurance recoveries of some of the amounts due to exceeding aggregate loss limits per event. We expect the remaining repair costs to be incurred in 2007 and the insurance reimbursements to be received in 2007 and 2008. While we do not believe the unrecovered costs will materially impact our overall liquidity or financial results, the timing between expenditures and reimbursements may impact our liquidity from period to period. The table below provides further detail on what we have spent to date, our estimated remaining costs, and insurance recoveries (in millions).

	Recoverable Costs	Unrecoverable Costs[1]	Total
Cumulative costs through 2006	$190	$265	$455
Estimated remaining costs	75	95	170
Total costs	265	$360	$625
Less: Reimbursements to date	(55)		
Expected future reimbursements	$210		

(1) Includes capital expenditures of approximately $275 million.

Our mutual insurance company has also indicated that effective June 1, 2006, the aggregate loss limits on future events has been reduced to $500 million from $1 billion, which could further limit our recoveries on future hurricanes or other insurable events.

Price Risk Management Activities. Our Exploration and Production and Marketing segments enter into derivative contracts to provide price protection on a portion of our anticipated natural gas and oil production. During 2006, we entered into additional derivative contracts related to a significant portion of our 2007 natural gas production. The following table shows as of December 31, 2006, the contracted volumes and the minimum, maximum and average cash prices that we will receive under these contracts when combined with the sale of the underlying production. These cash prices may differ from the income impacts of our derivative contracts, depending on whether the contracts are designated as hedges for accounting purposes or not. The individual segment discussions provide additional information on the income impacts of our derivative contracts.

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)
	Volumes	Price	Volumes	Price	Volumes	Price	Volumes
Natural Gas							
2007	78	$ 7.70	144	$ 7.69	55	$16.89	110
2008	5	$ 3.42	18	$ 6.00	18	$10.00	—
2009	5	$ 3.56	17	$ 6.00	17	$ 8.75	—
2010-2012	11	$ 3.81	—	—	—	—	—
Oil							
2007	192	$35.15	1,009	$55.00	1,009	$60.38	—
2008	—	—	930	$55.00	930	$57.03	—

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.
(2) Our basis swaps effectively "lock-in" locational price differences on a portion of our natural gas production in Texas and Oklahoma.

Overview of Cash Flow Activities for 2006 Compared to 2005

	Years Ended December 31, 2006	2005
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Net income (loss) before discontinued operations	$ 0.5	$(0.5)
Non-cash income adjustments	1.1	1.1
Change in broker margin and other deposits	0.9	(0.7)
Change in other assets and liabilities	(0.7)	0.1
Total cash flow from operations	$ 1.8	$ —
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.7	$ 1.4
Other	0.2	0.2
	0.9	1.6
Continuing financing activities		
Net proceeds from the issuance of long-term debt	0.4	1.6
Proceeds from issuance of common and preferred stock	0.5	0.7
Contribution from discontinued operations[1]	0.2	0.7
	1.1	3.0
Total other cash inflows	$ 2.0	$ 4.6
Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 2.2	$ 1.6
Net cash paid for acquisition	—	1.0
	2.2	2.6
Continuing financing activities		
Payments to retire long-term debt and redeem preferred interests	3.0	1.5
Redemption of preferred stock of a subsidiary	—	0.3
Dividends and other	0.2	0.2
	3.2	2.0
Total other cash outflows	$ 5.4	$ 4.6
Net change in cash	$(1.6)	$ —

[1] Amounts contributed from discontinued operations above are net of approximately $0.2 billion of debt repayments associated with the Macae power facility.

In 2006, we continued to expand our core pipeline and exploration and production businesses and reduce our debt obligations. During 2006 we generated positive operating cash flow of approximately $1.8 billion, primarily a result of cash provided by our pipeline and exploration and production operations, $0.4 billion received from the settlement of derivative contracts, and the return of approximately $0.9 billion of broker margins related to our derivative contracts. We utilized this operating cash flow, along with proceeds from asset sales and the issuance of long-term debt and common stock, as well as available cash to (i) fund both maintenance and growth projects of approximately $1.0 billion in our pipeline operations and $1.1 billion in our exploration and production operations and (ii) repay debt. As noted above, our ability to utilize cash on hand for debt repayment was based on maintaining lower levels of cash and available liquidity in the ordinary course of business due to the simplification of our business and capital structure.

Off-Balance Sheet Arrangements

In the course of our business activities, we enter into a variety of financing arrangements and contractual obligations. Certain of these arrangements are often referred to as off-balance sheet arrangements and include guarantees, letters of credit and other interests in variable interest entities.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. For example, if the guaranteed party is required to purchase services from a third party and then fails to do so, we would be required to either purchase these services or make payments to the third party to compensate them for any losses they incurred because of this non-performance. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental matters and necessary expenditures to ensure the safety and integrity of the assets sold.

We record accruals for our guaranty and indemnification arrangements at their fair value when they are issued and subsequently adjust those accruals when we believe it is both probable that we will have to pay amounts under the arrangements and those amounts can be estimated. As of December 31, 2006, we had a liability of $71 million related to guarantees and indemnification arrangements. These arrangements had a total stated exposure of $376 million, for which we are indemnified by third parties for $18 million. These amounts exclude guarantees for which we have issued related letters of credit discussed below. Included in the above stated value of $376 million is approximately $120 million associated with tax matters, related interest, and other indemnifications arising out of the sale of our Macae power facility in 2006.

In addition to the exposures described above, we received a ruling from a trial court, which was upheld on appeal, that we are required to indemnify a third party for benefits paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $379 million associated with our estimated exposure under this matter as of December 31, 2006. For a further discussion of this matter, see Part II, Item 8 Financial Statements and Supplementary Data, Notes 13 and 14.

Letters of Credit

We enter into letters of credit in the ordinary course of our operations as well as periodically in conjunction with sales of assets or businesses. As of December 31, 2006, we had outstanding letters of credit of approximately $1.4 billion, including $1.1 billion of letters of credit securing our recorded obligations related to price risk management activities.

Interests in Variable Interest Entities

We have interests in several variable interest entities, primarily investments held in our Power segment. A variable interest entity is a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. We are required to consolidate such entities if we are allocated the majority of the variable interest entity's losses or return, including fees paid by the entity. As of December 31, 2006, we do not consolidate seven variable interest entities since we are not the primary beneficiary of the variable interest entity's operations. For additional information regarding our interests in those entities, see Part II, Item 8 Financial

Statements and Supplementary Data, Note 18, Investments in, Earnings from and Transactions with Unconsolidated Affiliates.

Contractual Obligations

We are party to various contractual obligations, which include the off-balance sheet arrangements described above. A portion of these obligations are reflected in our financial statements, such as long-term debt, liabilities from commodity-based derivative contracts and other accrued liabilities, while other obligations, such as demand charges under transportation and storage commitments and operating leases and capital commitments, are not reflected on our balance sheet. The following table and discussion that follows summarizes our contractual cash obligations as of December 31, 2006, for each of the periods presented (all amounts are undiscounted except liabilities from commodity-based derivative contracts):

	Due in Less than 1 Year	Due in 1 to 3 Years	Due in 4 to 5 Years	Thereafter	Total
			(In millions)		
Long-term financing obligations:					
Principal	$1,360	$2,225	$2,559	$ 8,616	$14,760
Interest	1,090	1,997	1,608	9,035	13,730
Liabilities from commodity-based derivative contracts	278	435	263	226	1,202
Other contractual liabilities	70	44	27	35	176
Operating leases	66	17	4	11	98
Other contractual commitments and purchase obligations:					
Transportation and storage	98	81	68	153	400
Other	424	66	24	26	540
Total contractual obligations	$3,386	$4,865	$4,553	$18,102	$30,906

Long Term Financing Obligations (Principal and Interest). Debt obligations included represent stated maturities unless otherwise puttable to us prior to their stated maturity date. Contractual interest payments are shown through the stated maturity date of the related debt. For a further discussion of our debt obligations see Item 8, Financial Statements and Supplementary Data, Note 12. Excluded from the amounts in the table above are $744 million of principal and $703 million of interest related to ANR which is reported in discontinued operations.

Liabilities from Commodity-Based Derivative Contracts. These amounts only include the fair value of our price risk management liabilities. The fair value of our price risk management assets of $807 million as of December 31, 2006 is not reflected in these amounts. We have also excluded margin and other deposits held associated with these contracts from these amounts. For a further discussion of our commodity-based derivative contracts, see the discussion of commodity-based derivative contracts below.

Other Contractual Liabilities. Included in this amount are contractual, environmental and other obligations included in other current and non-current liabilities in our balance sheet. We have excluded from these amounts expected contributions to our pension and other postretirement benefit plans of $144 million for the four year period ended December 31, 2010, because these expected contributions are not contractually required. Also excluded are potential amounts due under an indemnification of a former subsidiary for benefits being paid to a closed group of retirees, for which we have a liability of approximately $379 million related to the litigation associated with this matter as of December 31, 2006.

Operating Leases. For a further discussion of these obligations, see Part II, Item 8 Financial Statements and Supplementary Data, Note 13.

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. Included are the following:

- *Transportation and Storage Commitments.* Included in these amounts are commitments for demand charges for firm access to natural gas transportation and storage capacity.
- *Other Commitments.* Included in these amounts are commitments for drilling and seismic activities in our exploration and production operations and various other maintenance, engineering, procurement and construction contracts, as well as service and license agreements used by our other operations. We have excluded asset retirement obligations and reserves for litigation, environmental remediation and self-insurance claims as liabilities are not contractually fixed as to timing and amount. We have excluded from these amounts contractual commitments of $223 million related to ANR which is reported in discontinued operations.

Commodity-Based Derivative Contracts. We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. In the tables below, derivatives designated as hedges primarily consist of collars and swaps used to hedge natural gas production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps and other natural gas and power purchase and supply contracts. The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of December 31, 2006:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges[1]						
Assets	$ 144	$ —	$ —	$ —	$—	$ 144
Liabilities	(17)	(36)	(25)	(5)	—	(83)
Total derivatives designated as hedges	127	(36)	(25)	(5)	—	61
Other commodity-based derivatives						
Exchange-traded positions[1]						
Assets	128	208	17	—	—	353
Non-exchange traded positions						
Assets	162	66	40	34	8	310
Liabilities	(261)	(399)	(238)	(215)	(6)	(1,119)
Total other commodity-based derivatives	29	(125)	(181)	(181)	2	(456)
Total commodity-based derivatives	$ 156	$(161)	$(206)	$(186)	$ 2	$ (395)

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

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2006 and 2005:

	Derivatives Designated as Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at December 31, 2004	$(536)	$ 604	$ 68
Fair value of contract settlements during the period[1]	665	(174)	491
Change in fair value of contracts	(793)	(767)	(1,560)
Assignment of contracts	—	(442)	(442)
Reclassification of derivatives that no longer qualify as hedges	11	(11)	—
Option premiums paid[2]	—	27	27
Net change in contracts outstanding during the period	(117)	(1,367)	(1,484)
Fair value of contracts outstanding at December 31, 2005	(653)	(763)	(1,416)
Fair value of contract settlements during the period[1]	204	38	242
Change in fair value of contracts	514	154	668
Assignment of contracts	—	36	36
Other commodity-based derivatives subsequently designated as hedges	(16)	16	—
Reclassification of derivatives that no longer qualify as hedges	6	(6)	—
Option premiums paid[2]	6	69	75
Net change in contracts outstanding during the period	714	307	1,021
Fair value of contracts outstanding at December 31, 2006	$ 61	$ (456)	$ (395)

(1) Includes derivative contracts sold/terminated.
(2) Amounts are net of premiums received.

Fair Value of Contract Settlements. The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts, including amounts received from the sale of option contracts.

Changes in Fair Value of Contracts. The change in fair value of contracts during the year represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement, early termination or, if not settled or terminated, until the end of the period. In 2006, the change in fair value also includes a loss on natural gas supply agreements related to MCV upon the sale of our interest in this facility.

Assignment of Contracts. In 2005, we entered into an agreement to assign the majority of our power derivative assets to Morgan Stanley and received total proceeds of $442 million. In 2006, we sold or entered into offsetting derivative transactions to eliminate the price risk associated with a substantial portion of our remaining historical natural gas derivatives. We paid proceeds of approximately $32 million related to this transaction.

Designation and Reclassifications of Hedges. During 2005 and 2006, we removed the hedging designation on certain derivative contracts where we experienced decreases in the related anticipated hedged production volumes in Brazil. Also, during 2006 we designated certain existing other commodity-based derivatives as hedges of our anticipated 2007 natural gas production.

Critical Accounting Estimates

Our significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K. The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting estimates and to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expenses and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those that require difficult, complex, or subjective judgment necessary in accounting for inherently uncertain matters. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. We have discussed the development and selection of the following critical accounting estimates and related disclosures with the Audit Committee of our Board of Directors.

Accounting for Natural Gas and Oil Producing Activities. Our estimates of proved reserves reflect quantities of natural gas, oil and NGLs which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic conditions. Natural gas and oil reserves estimates underlie a number of the accounting estimates in our financial statements. The process of estimating natural gas and oil reserves, particularly proved undeveloped and proved non-producing reserves, is complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. Our reserve estimates are developed internally by a reserve reporting group separate from our operations group and reviewed by internal committees and internal auditors. In addition, a third-party reservoir engineering firm, which is appointed by and reports to the Audit Committee of our Board of Directors, prepares an independent estimate of a significant portion of our proved reserves. As of December 31, 2006, of our total proved reserves, 29 percent were undeveloped and 11 percent were developed, but non-producing. In addition, the data for a given field may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates.

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

Natural gas and oil properties include unproved property costs that are excluded from costs being depleted. These unproved property costs include non-producing leasehold, geological and geophysical costs associated with leasehold or drilling interests and exploration drill costs in investments in unproved properties and major development projects in which we own a direct interest. We exclude these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if exclusion from the full-cost pool continues to be appropriate. If costs are determined to be impaired, the amount of any impairment is transferred to the full cost pool if a reserve base exists or is expensed if a reserve base has not yet been created. Impairments transferred to the full cost pool increase the depletion rate for that country.

Under the full cost accounting method, we are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This impairment test is referred to as a ceiling test. Our total capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted 10 percent, net of related income tax effects, plus the lower of cost or fair market value of unproved properties. We utilize end of period spot prices when calculating future net revenues unless those prices result in a ceiling test charge in which case we evaluate price recoveries subsequent to the end of the period. If the discounted revenues are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. Our ceiling test calculations include the effect of derivative instruments we have designated as, and that qualify as hedges of our anticipated natural gas and oil production. Higher proved reserves can reduce the likelihood of ceiling test impairments. We had no ceiling test charges in 2006 and 2005 and recorded ceiling test charges of $35 million during 2004.

The ceiling test calculation assumes that the price in effect on the last day of the quarter is held constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. A decline in commodity prices can impact the results of our ceiling test and may result in a write-down. A decrease in commodity prices of 10 percent from the price levels at December 31, 2006 would not have resulted in a ceiling test charge in 2006.

Accounting for Legal and Environmental Reserves. We accrue legal and environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. Estimates of our liabilities are based on our evaluation of potential outcomes, currently available facts, and in the case of environmental reserves, existing technology and presently enacted laws and regulations taking into consideration the likely effects of societal and economic factors, estimates of associated onsite, offsite and groundwater technical studies and legal costs. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each matter.

As of December 31, 2006, we had accrued approximately $548 million for legal matters, which includes approximately $379 million associated with an indemnity for certain retiree benefit payments, which is further discussed below. We have accrued $314 million for environmental matters. Our environmental estimates range from approximately $314 million to approximately $532 million, and the amounts we have accrued represent a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($27 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($287 million to $505 million) and the lower end of the expected range has been accrued.

Accounting for Pension and Other Postretirement Benefits. During the fourth quarter of 2006, we adopted the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an Amendment of FASB Statements No. 87, 88, 106 and 132(R).* Under this standard, we reflect an asset or liability for our pension and other postretirement benefit plans based on their over funded or under funded status. As of December 31, 2006, our combined pension plans were over funded by $228 million and our combined other postretirement benefit plans were under funded by $209 million. Our pension and other postretirement benefit assets and liabilities are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plans and other factors. A significant assumption we utilize is the discount rates used in calculating our benefit obligations. We compare our discount rates based on the average expected timing of our pension and other postretirement obligations to the maturity profiles of the Moody's Corporate Bond Indices and the Citigroup Pension Discount Curve. Based on these comparisons, we select discount rates that appropriately reflect the yields included in these market sources adjusted for the estimated timing of our obligations.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and other postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations, along with changes to the plans and other items, are deferred in accumulated other comprehensive income and amortized into income over either the period of expected future service of active participants, or over the lives of the plan participants. The cumulative amount deferred in accumulated other comprehensive loss as of December 31, 2006 was approximately $435 million, net of income taxes. The following table shows the impact of a one percent change in the primary assumptions used in our actuarial calculations associated with our pension and other postretirement benefits for the year ended December 31, 2006 (in millions):

	Pension Benefits		Other Postretirement Benefits	
	Net Benefit Expense (Income)	Change in Net Asset and Pretax Accumulated Other Comprehensive Loss	Net Benefit Expense (Income)	Change in Net Liability and Pretax Accumulated Other Comprehensive Income
One percent increase in:				
Discount rates	$(12)	$(195)	$—	$(38)
Expected return on plan assets	(22)	—	(2)	—
Rate of compensation increase	2	4	—	—
Health care cost trends	—	—	1	18
One percent decrease in:				
Discount rates	$ 12	$ 232	$ (1)	$ 41
Expected return on plan assets[(1)]	22	—	2	—
Rate of compensation increase	(2)	(3)	—	—
Health care cost trends	—	—	(1)	(15)

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

The estimates for our net benefit expense or income are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred over three years, after which they are considered for inclusion in net benefit expense or income. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit expense would have been $15 million lower for the year ended December 31, 2006.

As stated in Financial Statements and Supplementary Data, Note 14, we were ordered to indemnify a third party for certain benefit payments being made to a closed group of retirees pending the outcome of litigation related to these payments. We estimated the initial liability associated with this indemnification obligation using actuarial methods similar to those used in estimating our obligations on our other postretirement benefit plans, which involves using various assumptions, including those related to discount rates and health care trends. A one percent change in the discount rate assumption used in the calculation would have changed the liability (and the related expense) by approximately $36 million and a one percent change in the health care cost trend assumption would have changed the liability (and the related expense) by approximately $49 million as of and for the year ended December 31, 2006.

Price Risk Management Activities. We record the derivative instruments used in our price risk management activities at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary assumptions used to estimate the fair value of derivative instruments is pricing. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. We adjust these price curves in certain areas (such as the Pennsylvania-New Jersey-Maryland region) based on our outlook of the liquidity of these markets which may differ from that of our derivative counterparties. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from immediate selected potential changes in quoted market prices at December 31, 2006:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(In millions)			
Derivatives designated as hedges	$ 61	$ (19)	$ (80)	$ 144	$ 83
Other commodity-based derivatives	(456)	(529)	(73)	(378)	78
Total	$(395)	$(548)	$(153)	$(234)	$161

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to time value, anticipated market liquidity and the credit risk of our counterparties. The assumptions and methodologies we use to determine the fair values of our derivatives may differ from those used by our derivative counterparties, and these differences can be significant. As a result, the actual settlement of our price risk management activities could differ materially from the fair value recorded and could impact our future operating results.

Asset and Investment Impairments. The accounting rules on asset and investment impairments require us to continually monitor our businesses and the business environment to determine if an event has occurred that indicates that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then estimate the fair value of the asset, which considers a number of factors, including the potential value we would receive if we sold the asset and the projected cash flows of the asset based on current and anticipated future market conditions. The assessment of project level cash flows requires judgment to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors. Actual results can, and often do, differ from our estimates. If the carrying value of the asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its fair value. We recorded impairments of our long-lived assets of $16 million, $73 million and $1.1 billion and impairments on our investments in unconsolidated affiliates of $13 million, $347 million and $397 million during the years ended December 31, 2006, 2005 and 2004. We also recorded asset and investment impairments of our discontinued operations of $13 million, $502 million and $40 million, net of minority interest during the years ended December 31, 2006, 2005 and 2004. Future changes in the economic and business environment can impact our assessments of potential impairments.

New Accounting Pronouncements Issued But Not Yet Adopted

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

- Commodity Price Risk
  - Natural gas and oil price changes, impacting the sale of natural gas and oil in our Exploration and Production segment and gas not used in the operations of our Pipelines segment;
  - Natural gas locational price differences change, affecting our ability to optimize pipeline transportation capacity contracts held in our Marketing segment; and
  - Electricity and natural gas price changes and locational pricing changes, affecting the value of our natural gas contracts and remaining power contracts held in our Marketing segment.
- Interest Rate Risk
  - Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed-rate debt;
  - Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions; and
  - Changes in interest rates used to discount liabilities which can result in higher or lower accretion expense over time.
- Foreign Currency Exchange Rate Risk
  - Weakening or strengthening of the U.S. dollar relative to the Euro can result in an increase or decrease in the value of our Euro-denominated debt obligations and/or the related interest costs associated with that debt

We manage our risks by entering into contractual commitments involving physical or financial settlement that attempt to limit exposure related to future market movements. The timing and extent of our risk management activities is based on a number of factors, including our market outlook, risk tolerance and liquidity. Our risk management activities typically involve the use of the following types of contracts:

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

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

Commodity Price Risk

Production-Related Derivatives

Our Exploration and Production and Marketing segments attempt to mitigate commodity price risk and stabilize cash flows associated with El Paso's forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks.

The table below was changed to reflect our current practice of managing our production-related risks in both our Exploration and Production and Marketing segments, which includes the use of all production-related derivative contracts, whether they are designated as hedges or not. Those contracts that are designated as hedges will impact our earnings when the sale of the related hedged items occurs, and, as a result, any gain or loss on these hedging derivatives would be substantially offset by a corresponding gain or loss on the underlying hedged commodity sale, which is not included in the table. Those contracts that are not designated as hedges will impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risk related to our forecasted sales of natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
Impact of changes in commodity prices on production-related derivative instruments					
December 31, 2006	$ 124	$ (9)	$(133)	$ 264	$140
December 31, 2005	$(942)	$(1,175)	$(233)	$(713)	$229

Other Commodity-Based Derivatives

Our Marketing segment also has various other financial instruments that are not utilized to mitigate the commodity price risk associated with our natural gas and oil production. We measure risks from these contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts due to adverse market movements over a defined period of time within a specified confidence level and allows us to monitor our risk in comparison to established thresholds. We use what is known as the historical simulation technique for measuring Value-at-Risk. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio's sensitivity to underlying risks. These analyses and our Value-at-Risk simulations were changed to exclude our production-related derivatives, which are included in the sensitivity analyses described above, our Marketing segment's natural gas transportation related contracts that are accounted for under the accrual basis of accounting, and our Exploration and Production segment's sales of natural gas and oil production.

Our maximum expected one-day unfavorable impact on the fair values of our other commodity-based derivatives as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $6 million and $29 million as of December 31, 2006 and 2005. Our highest, lowest and average of the month-end values for Value-at-Risk during 2006 was $14 million, $3 million and $7 million. Our Value-at-Risk decreased significantly during 2006 primarily due to the assignment of certain of our power and natural gas derivatives to third parties. We may experience changes in our Value-at-Risk in the future if commodity prices are volatile.

Interest Rate Risk

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average interest rates on our long-term interest-bearing securities by expected maturity dates as well as the total fair value of those securities. The fair value of the securities has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2006								December 31, 2005	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair Value	Carrying Amounts	Fair Value
	2007	2008	2009	2010	2011	Thereafter	Total			
	(In millions)									
Long-term debt and other obligations, including current portion — fixed rate	$1,345	$642	$1,363	$1,228	$1,143	$8,372	$14,093	$14,891	$15,278	$15,619
Average interest rate	7.1%	6.9%	7.4%	8.4%	7.4%	7.7%				
Long-term debt and other obligations, including current portion — variable rate	$ 13	$ 13	$ 214	$ 160	$ 16	$ 180	$ 596	$ 596	$ 1,988	$ 1,988
Average interest rate	6.2%	6.2%	7.1%	5.4%	6.2%	6.2%				

Foreign Currency Exchange Rate Risk

Our exposure to foreign currency exchange rates relates primarily to changes in foreign currency rates on our Euro-denominated debt obligations. As of December 31, 2006, we have Euro-denominated debt with a principal amount of €500 million which matures in 2009. As of December 31, 2006 and 2005, we had swaps that effectively converted €350 million and €367 million of this debt into $402 million and $418 million. The remaining principal at December 31, 2006 and 2005 of € 150 million and €155 million was subject to foreign currency exchange risk. A $0.10 change in the Euro to U.S. dollar exchange rate would result in a $15 million gain or loss on our unhedged Euro-denominated debt as of December 31, 2006.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by SEC rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, we used the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2006. Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Ernst and Young LLP, an independent registered public accounting firm, as stated in their report included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited the accompanying consolidated balance sheet of El Paso Corporation as of December 31, 2006, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for year then ended. Our audit also included the financial statement schedule listed in the Index at Item 15(a) for the year ended December 31, 2006. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audit. The financial statements of Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company (corporations in which the Company has a 50% and 43.1% interest, respectively) have been audited by other auditors whose reports have been furnished to us, and our opinion on the consolidated financial statements, insofar as it relates to the amounts included for Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company, is based solely on the reports of the other auditors. In the consolidated financial statements, the Company's combined investments in these companies represent approximately 3% of total assets as of December 31, 2006, and earnings from these investments represent approximately 24% of income before income taxes from continuing operations for the year then ended.

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

In our opinion, based on our audit and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of El Paso Corporation at December 31, 2006, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006 the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(revised 2004), *Share-Based Payment* and the Federal Energy Regulatory Commission's accounting release related to pipeline assessment costs, and effective December 31, 2006 the Company adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R).*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of El Paso Corporation's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that El Paso Corporation maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). El Paso Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that El Paso Corporation maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, El Paso Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2006 consolidated financial statements of El Paso Corporation and our report dated February 26, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
El Paso Corporation:

In our opinion, the consolidated balance sheet as of December 31, 2005 and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2005 present fairly, in all material respects, the financial position of El Paso Corporation and its subsidiaries (the "Company") at December 31, 2005, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended December 31, 2005 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in the notes to the consolidated financial statements, the Company adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations,* on December 31, 2005.

/s/ PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 2, 2006, except for the eleventh paragraph
of Note 2, as to which the date is May 10, 2006
and the tenth paragraph of Note 2, as to which
the date is February 26, 2007

Report of Independent Registered Public Accounting Firm

To the Stockholders of Four Star Oil & Gas Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Four Star Oil & Gas Company (the "Company") and its subsidiary at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, the Company has significant transactions with affiliated companies. Because of these relationships, it is possible that the terms of these transactions are not the same as those that would result from transactions among wholly unrelated parties.

/s/ PRICEWATERHOUSECOOPERS LLP

February 23, 2007
Houston, Texas

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Citrus Corp. and Subsidiaries:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity, of comprehensive income and of cash flows present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the "Company") at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with the accounting principles generally accepted in the United States of America. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 2 and 6 to the consolidated financial statements, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R)," as of December 31, 2006.

/s/ PRICEWATERHOUSECOOPERS LLP

Houston, Texas
February 26, 2007

EL PASO CORPORATION

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Operating revenues			
Pipelines	$ 2,402	$ 2,171	$ 2,145
Exploration and Production	1,854	1,787	1,735
Marketing	(58)	(796)	(508)
Power	6	82	402
Field Services	—	123	1,097
Corporate and eliminations	77	(8)	(88)
	4,281	3,359	4,783
Operating expenses			
Cost of products and services	238	245	1,168
Operation and maintenance	1,319	1,861	1,565
Depreciation, depletion and amortization	1,047	1,006	962
Loss on long-lived assets	18	74	1,077
Taxes, other than income taxes	232	234	197
	2,854	3,420	4,969
Operating income (loss)	1,427	(61)	(186)
Earnings from unconsolidated affiliates	145	281	479
Other income	245	285	175
Other expenses	(67)	(47)	(94)
Interest and debt expense	(1,228)	(1,286)	(1,497)
Distributions on preferred interests of consolidated subsidiaries	—	(9)	(25)
Income (loss) before income taxes from continuing operations	522	(837)	(1,148)
Income taxes	(9)	(331)	(116)
Income (loss) from continuing operations	531	(506)	(1,032)
Discontinued operations, net of income taxes	(56)	(96)	85
Cumulative effect of accounting changes, net of income taxes	—	(4)	—
Net income (loss)	475	(606)	(947)
Preferred stock dividends	37	27	—
Net income (loss) available to common stockholders	$ 438	$ (633)	$ (947)
Basic earnings (loss) per common share			
Income (loss) from continuing operations	$ 0.73	$ (0.82)	$ (1.61)
Discontinued operations, net of income taxes	(0.08)	(0.15)	0.13
Cumulative effect of accounting changes, net of income taxes	—	(0.01)	—
Net income (loss) per common share	$ 0.65	$ (0.98)	$ (1.48)
Diluted earnings (loss) per common share			
Income (loss) from continuing operations	$ 0.72	$ (0.82)	$ (1.61)
Discontinued operations, net of income taxes	(0.08)	(0.15)	0.13
Cumulative effect of accounting changes, net of income taxes	—	(0.01)	—
Net income (loss) per common share	$ 0.64	$ (0.98)	$ (1.48)

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 537	$ 2,132
Accounts and notes receivable		
Customer, net of allowance of $28 in 2006 and $65 in 2005	516	1,025
Affiliates	192	59
Other	495	146
Assets from price risk management activities	436	641
Margin and other deposits held by others	60	1,124
Assets held for sale and from discontinued operations	4,161	349
Deferred income taxes	478	391
Other	292	318
Total current assets	7,167	6,185
Property, plant and equipment, at cost		
Pipelines	15,672	14,767
Natural gas and oil properties, at full cost	16,572	15,738
Other	566	651
	32,810	31,156
Less accumulated depreciation, depletion and amortization	16,132	15,604
Total property, plant and equipment, net	16,678	15,552
Other assets		
Investments in unconsolidated affiliates	1,707	2,165
Assets from price risk management activities	414	1,368
Assets from discontinued operations	—	4,300
Other	1,295	2,270
	3,416	10,103
Total assets	$27,261	$31,840

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2006	December 31, 2005
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 478	$ 807
Affiliates	3	3
Other	569	519
Short-term financing obligations, including current maturities	1,360	984
Liabilities from price risk management activities	278	1,418
Liabilities related to discontinued operations	1,817	563
Margin deposits held by us	344	497
Accrued interest	269	274
Other	1,033	647
Total current liabilities	6,151	5,712
Long-term financing obligations, less current maturities	13,329	16,282
Other		
Liabilities from price risk management activities	924	2,005
Deferred income taxes	950	549
Liabilities related to discontinued operations	—	1,669
Other	1,690	2,203
	3,564	6,426
Commitments and contingencies		
Securities of subsidiaries	31	31
Stockholders' equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares of 4.99% convertible perpetual stock; stated at liquidation value	750	750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 705,833,206 shares in 2006 and 667,082,043 shares in 2005	2,118	2,001
Additional paid-in capital	4,804	4,592
Accumulated deficit	(2,940)	(3,415)
Accumulated other comprehensive loss	(343)	(332)
Treasury stock (at cost); 8,715,288 shares in 2006 and 7,620,272 shares in 2005	(203)	(190)
Unamortized compensation	—	(17)
Total stockholders' equity	4,186	3,389
Total liabilities and stockholders' equity	$27,261	$31,840

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2006	2005	2004
Cash flows from operating activities			
Net income (loss)	$ 475	$ (606)	$ (947)
Less income (loss) from discontinued operations, net of income taxes	(56)	(96)	85
Net income (loss) before discontinued operations	531	(510)	(1,032)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	1,047	1,006	962
Deferred income tax benefit	(20)	(303)	(140)
Loss on long-lived assets	18	74	1,077
Earnings from unconsolidated affiliates, adjusted for cash distributions	(6)	(78)	(219)
Other non-cash income items	80	356	433
Asset and liability changes			
Accounts and notes receivable	344	122	491
Change in price risk management activities, net	(420)	325	191
Accounts payable	(382)	(118)	(334)
Change in margin and other deposits	911	(679)	97
Western Energy Settlement liability	—	(395)	(626)
Other asset changes	(179)	177	11
Other liability changes	(100)	(10)	(252)
Cash provided by (used in) continuing activities	1,824	(33)	659
Cash provided by discontinued activities	279	301	657
Net cash provided by operating activities	2,103	268	1,316
Cash flows from investing activities			
Capital expenditures	(2,164)	(1,589)	(1,651)
Cash paid for acquisitions, net of cash acquired	—	(1,025)	(50)
Net proceeds from the sale of assets and investments	673	1,424	1,927
Net change in restricted cash	129	(57)	552
Other	23	204	134
Cash provided by (used in) continuing activities	(1,339)	(1,043)	912
Cash provided by discontinued activities	185	542	991
Net cash provided by (used in) investing activities	(1,154)	(501)	1,903
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	375	1,620	1,254
Payments to retire long-term debt and other financing obligations	(3,024)	(1,491)	(3,052)
Repayment of notes payable	—	—	(214)
Net proceeds from the issuance of common stock	500	—	73
Dividends paid	(145)	(121)	(101)
Net proceeds from issuance of preferred stock	—	723	—
Payments to minority interest and preferred interest holders	(5)	(306)	(35)
Contributions from discontinued operations	232	666	1,225
Other	(13)	—	(33)
Cash provided by (used in) continuing activities	(2,080)	1,091	(883)
Cash used in discontinued activities	(464)	(843)	(1,648)
Net cash provided by (used in) financing activities	(2,544)	248	(2,531)
Change in cash and cash equivalents	(1,595)	15	688
Cash and cash equivalents			
Beginning of period	2,132	2,117	1,429
End of period	$ 537	$ 2,132	$ 2,117
Supplemental cash flow information related to continuing operations			
Interest paid, net of amounts capitalized	$ 1,217	$ 1,238	$ 1,431
Income tax payments	77	11	37

See accompanying notes

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions, except per share amounts)

	Year Ended December 31,					
	2006		2005		2004	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred stock, $0.01 par value:						
Balance at beginning of year	1	$ 750	—	$ —	—	$ —
Equity offering	—	—	1	750	—	—
Balance at end of year	1	750	1	750	—	—
Common stock, $3.00 par value:						
Balance at beginning of year	667	2,001	651	1,953	639	1,917
Exchange of equity security units	—	—	14	41	—	—
Equity offering	36	107	—	—	—	—
Other, net	3	10	2	7	12	36
Balance at end of year	706	2,118	667	2,001	651	1,953
Additional paid-in capital:						
Balance at beginning of year		4,592		4,538		4,576
Equity offering		393		—		—
Dividends		(147)		(131)		(104)
Compensation related issuances		(2)		(18)		15
Tax effects of equity plans		—		2		5
Exchange of equity security units		—		230		—
Other		(32)		(29)		46
Balance at end of year		4,804		4,592		4,538
Accumulated deficit:						
Balance at beginning of year		(3,415)		(2,809)		(1,862)
Net income (loss)		475		(606)		(947)
Balance at end of year		(2,940)		(3,415)		(2,809)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(332)		1		(40)
Other comprehensive income (loss)		380		(333)		41
Cumulative effect of adopting SFAS No. 158, net of income tax of $210		(391)		—		—
Balance at end of year		(343)		(332)		1
Treasury stock, at cost:						
Balance at beginning of year	(8)	(190)	(8)	(225)	(7)	(222)
Compensation related issuances	—	—	1	47	—	9
Other	(1)	(13)	(1)	(12)	(1)	(12)
Balance at end of year	(9)	(203)	(8)	(190)	(8)	(225)
Unamortized compensation:						
Balance at beginning of year		(17)		(20)		(23)
Issuance of restricted stock		—		(22)		(28)
Amortization of restricted stock		—		18		23
Forfeitures of restricted stock		—		7		9
Adoption of SFAS No. 123(R),		17		—		(1)
Balance at end of year		—		(17)		(20)
Total stockholders' equity	697	$ 4,186	659	$ 3,389	643	$ 3,438

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2006	2005	2004
Net income (loss)	$475	$(606)	$(947)
Foreign currency translation adjustments (net of income tax benefits of less than $1 in 2006, $13 in 2005 and $38 in 2004)	4	(9)	11
Change in minimum pension liability (net of income tax of $3 in 2006, $2 in 2005, and $11 in 2004)	5	(3)	(22)
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income tax of $196 in 2006, $229 in 2005, and $8 in 2004)	352	(415)	22
Reclassification adjustments for changes in initial value to settlement date (net of income tax of $15 in 2006, $46 in 2005, and $8 in 2004)	22	79	30
Net gains from investments available for sale:			
Unrealized gains arising during period (net of income tax of $16 in 2006 and $9 in 2005)	28	15	—
Realized gains reclassified from accumulated other comprehensive income during period (net of income tax of $17 in 2006)	(31)	—	—
Other comprehensive income (loss)	380	(333)	41
Comprehensive income (loss)	$855	$(939)	$(906)

See accompanying notes.

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles (GAAP) and include the accounts of all majority owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements have been adjusted in all periods to reflect the reclassification of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission, as well as our Macae power facility as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. These reclassifications did not impact our reported net income (loss) or stockholders' equity.

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interests (see Note 18) in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the policies and decisions of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity.

Use of Estimates

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

Regulated Operations

Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Our pipelines follow the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Under SFAS No. 71 we record regulatory assets and liabilities that would not be recorded under GAAP for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Items to which we apply regulatory accounting requirements include certain postretirement employee benefit plan costs, an equity return component on regulated capital projects and certain costs included in, or expected to be included in, future rates.

Cash and Cash Equivalents

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

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets on our balance sheet based on when we expect the restrictions on this cash to be removed. As of December 31, 2006, we had $8 million of restricted cash in current assets and $123 million in other non-current assets. As of December 31, 2005, we had $92 million of restricted cash in other current assets and $168 million in other non-current assets.

Allowance for Doubtful Accounts

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

Property, Plant and Equipment

Pipelines and Other (Excluding Natural Gas and Oil Properties). Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and, an equity return component in our regulated businesses. We capitalize the major units of property replacements or improvements and expense minor items. Prior to January 1, 2006, we capitalized certain costs our interstate pipelines incurred related to their pipeline integrity programs as part of our property, plant and equipment. Beginning January 1, 2006, we began expensing these costs based on FERC guidance. During the year ended December 31, 2006, we expensed approximately $19 million as a result of the adoption of this accounting release, which was approximately $0.02 per basic and fully diluted share.

Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems' property, plant and equipment. These costs are amortized on a straight-line basis and we do not recover these excess costs in our rates.

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

Natural Gas and Oil Properties. We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves are capitalized on a country-by-country basis. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and periodically assessed for impairment through a ceiling test calculation discussed below.

Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated, which occurs quarterly. We transfer unproved property costs into the amortizable base when properties are determined to have proved reserves. In addition, in areas where a natural gas or oil reserve base exists, we transfer unproved property costs to the amortizable base when unproved properties are evaluated as being impaired and as exploratory dry holes are determined to be unsuccessful. Additionally, the amortizable base includes future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values; and geological and geophysical costs incurred that cannot be associated with specific unevaluated properties or prospects in which we own a direct interest.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues discounted at 10 percent plus the lower of cost or fair market value of unproved properties, net of related income tax effects. We utilize end-of-period spot prices when calculating future net revenues unless those prices result in a ceiling test charge in which case we evaluate price recoveries subsequent to the end of the period. If total capitalized costs exceed the ceiling, we are required to write-down our capitalized costs to the ceiling. We perform this ceiling test calculation each quarter. Any required write-down is included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production. Our ceiling test calculations exclude the estimated future cash outflows associated with asset retirement liabilities related to proved developed reserves.

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

Asset and Investment Divestitures/ Impairments

We evaluate assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) our long-lived assets' ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investments in unconsolidated affiliates. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying values of these assets downward, if necessary, to their estimated fair value. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairment is impacted by a number of factors, including the nature of the assets being sold and our established time frame for completing the sales, among other factors.

We reclassify the asset or assets to be sold as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have significant long-term continuing involvement with those assets after they are sold. We cease depreciating assets in the period that they are reclassified as either held for sale or discontinued operations.

Pension and Other Postretirement Benefits

We maintain several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense related to these plans in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected returns on plan assets and amortization of certain deferred gains and losses. For a further discussion of our policies with respect to our pension and postretirement plans, See Note 14.

Effective December 31, 2006, we adopted the recognition provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an Amendment of FASB Statements No. 87, 88, 106 and 132(R).* Under SFAS No. 158, we record an asset or liability for our pension and other postretirement benefit plans based on their overfunded or underfunded status. Any deferred amounts related to unrealized gains and losses or changes in actuarial assumptions are recorded in accumulated other comprehensive income (loss), a component of stockholders' equity, until those gains and losses are recognized in the income statement. Prior to December 31, 2006, these deferred amounts were included in pension and other postretirement assets and liabilities in our balance sheets, and their reclassification to stockholders' equity will not impact our pension and other postretirement benefit expense included in our income statements. For a further discussion of the impact of the adoption of SFAS No. 158, see Note 14.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. We record revenues for these products and services which include estimates of amounts earned but unbilled. We estimate these unbilled revenues related to services provided or products delivered based on contract data, regulatory information, commodity prices, and preliminary throughput and allocation measurements, among other items. The revenue recognition policies of our most significant operating segments are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. Gas not needed for operations is based on the volumes we are allowed to retain relative to the amounts of gas we use for operating purposes. We recognize revenue from gas not used in operations when we retain the volumes under our tariffs. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. We are subject to FERC regulations and, as a result, revenues we collect in rate proceedings may be subject to refund. We establish reserves for these potential refunds.

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

Marketing revenues. Our Marketing segment derives revenues from physical natural gas and power transactions and the management of derivative contracts. Our derivative transactions are recorded at their fair value and changes in their fair value are reflected net in operating revenues. For a further discussion of our income recognition policies on derivatives see *Price Risk Management Activities* below. The impact of non-derivative transactions, including our transportation contacts, are recognized net in operating revenues based on the contractual or market price and related volumes at the time the commodity is delivered or the contracts are terminated.

Environmental Costs and Other Contingencies

Environmental Costs. We record liabilities at their undiscounted amounts on our balance sheet in other current and long-term liabilities when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and recognize a current period charge in operation and maintenance expense when clean-up efforts do not benefit future periods.

We evaluate any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties including insurance coverage separately from our liability. Recovery is evaluated based on the creditworthiness or solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our balance sheet.

Other Contingencies. We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

Price Risk Management Activities

Our price risk management activities consist of the following activities:

- derivatives entered into to hedge or otherwise reduce the commodity exposure on our natural gas and oil production and interest rate and foreign currency exposure on our long-term debt; and

- derivatives not intended to hedge these exposures, including those related to our historical trading activities that we entered into with the objective of generating profits from exposure to shifts or changes in market prices.

Our derivatives are reflected on our balance sheet at their fair value as assets and liabilities from price risk management activities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. See Note 8 for a further discussion of our price risk management activities.

Derivatives that we have designated as accounting hedges impact our revenues or expenses based on the nature and timing of the transactions that they hedge. Derivatives that we have not designated as hedges are marked-to-market each period and changes in their fair value are reflected as revenues.

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows (other than those derivatives intended to hedge the principal amounts of our foreign currency denominated debt). In our balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables.

Income Taxes

We record current income taxes based on our current taxable income and provide for deferred income taxes to reflect estimated future tax payments and receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

Foreign Currency Translation

For foreign operations whose functional currency is the local currency, assets and liabilities are translated at year-end exchange rates and revenues and expenses are translated at average exchange rates prevailing during the year. The cumulative effects of translating the local currency to the U.S. dollar are included as a separate component of accumulated other comprehensive income (loss) in stockholders' equity on our balance sheet.

Accounting for Asset Retirement Obligations

We account for our asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* and Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. We record a liability for legal obligations associated with the replacement, removal, or retirement of our long-lived assets. Our asset retirement liabilities are recorded at their estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. Our regulated pipelines have the ability to recover certain of these costs from their customers and have recorded an asset (rather than expense) associated with the depreciation of the property, plant and equipment and accretion of the liabilities described above.

Accounting for Stock-Based Compensation.

On January 1, 2006, we adopted SFAS No. 123(R), *Share-Based Payment* prospectively for awards of stock-based compensation granted after that date and for the unvested portion of outstanding awards at that date. This standard and its related interpretations require companies to measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in its financial statements over the requisite service period. Prior to January 1, 2006, we accounted for these plans using the intrinsic value method under the provisions of Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations, and did not record compensation expense on stock options that were granted at the market value of the stock on the date of grant. For additional information on our stock-based compensation awards, see Note 16.

We record stock-based compensation expense, excluding amounts capitalized, as operation and maintenance expense for each separately vesting portion of the award, net of estimates of forfeitures. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods. The adoption of SFAS No. 123(R) did not result in a significant cumulative effect to our financial statements. However, in 2006, we recognized an incremental $11 million of additional pre-tax compensation expense, capitalized approximately $2 million of this expense as part of fixed assets, recorded $4 million of income tax benefits and earnings per share decreased by $0.01 per basic and diluted share resulting from the implementation of this standard. Additionally, under SFAS No. 123(R), beginning January 1, 2006, excess tax benefits from the exercise of stock-based compensation awards are recognized in cash flows from financing activities. Prior to this date, these amounts were recorded in cash flows from operating activities. Our excess tax benefits recorded in 2006, 2005 and 2004 were not material.

The following table shows the impact on the net loss available to common stockholders and loss per share had we applied the provisions of SFAS No. 123 in historical periods (in millions, except for per share amounts):

	Year Ended December 31,	
	2005	2004
	(In millions, except per common share amounts)	
Net loss available to common stockholders, as reported	$ (633)	$ (947)
Add: Stock-based employee compensation expense included in reported net loss, net of taxes	12	14
Deduct: Total stock-based compensation expense determined under fair-value based method for all awards, net of taxes	(19)	(25)
Net loss available to common stockholders, pro forma	$ (640)	$ (958)
Loss per share:		
Basic and diluted, as reported	$(0.98)	$(1.48)
Basic and diluted, pro forma	$(0.99)	$(1.50)

Evaluation of Prior Period Misstatements in Current Financial Statements

In December 2006, we adopted the provisions of the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements.* SAB No. 108 provides guidance on how to evaluate the impact of financial statement misstatements from prior periods that have been identified in the current year. The adoption of these provisions did not have any impact on our financial statements.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2006, the following accounting standards and interpretations had not yet been adopted by us.

Accounting for Uncertainty in Income Taxes. In July 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes.* FIN No. 48 clarifies SFAS No. 109, *Accounting for Income Taxes,* and requires us to evaluate our tax positions for all jurisdictions and for all years where the statute of limitations has not expired. FIN No. 48 requires companies to meet a "more-likely-than-not" threshold (i.e. greater than a 50 percent likelihood of a tax position being sustained under examination) prior to recording a benefit for their tax positions. Additionally, for tax positions meeting this "more-likely-than-not" threshold, the amount of benefit is limited to the largest benefit that has a greater than 50 percent probability of being realized upon ultimate settlement. The cumulative effect of applying this interpretation will be recorded as an adjustment to the beginning balance of retained earnings, or other components of stockholders' equity, as appropriate, in the period of adoption. This interpretation is effective for fiscal years beginning after December 15, 2006, and we do not anticipate that it will have a material impact on our financial statements.

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which provides guidance on measuring the fair value of assets and liabilities in the financial statements. We will be required to adopt the provisions of this standard no later than 2008, and are currently evaluating the impact, if any, that it will have on our financial statements.

Measurement Date of Pension and Other Postretirement Benefits. In December 2006, we adopted the recognition provisions of SFAS No. 158. Beginning in 2008, this standard will also require us to change the measurement date of our pension and other postretirement benefit plans from September 30, the date we currently use, to December 31. We are currently evaluating the impact, if any, that the measurement date provisions of this standard will have on our financial statements.

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, *Fair Value Option for Financial Assets and Financial Liabilities* — including an Amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, which permits entities to choose to measure many financial instruments and certain other items at fair value. We will be required to adopt the provisions of this standard no later than 2008, and are currently evaluating the impact, if any, that it will have on our financial statements.

2. Acquisitions and Divestitures

Acquisitions

South Texas properties. In January, 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas, for approximately $249 million using funds borrowed under our EPEP $500 million credit facility.

Medicine Bow. In August 2005, we completed the acquisition of Medicine Bow, a privately held energy company, for total cash consideration of approximately $0.9 billion. Medicine Bow owns a 43.1 percent interest in Four Star, an unconsolidated affiliate. Our proportionate share of the operating results associated with Four Star is reflected as earnings from unconsolidated affiliates in our financial statements (see Note 18).

We have reflected Medicine Bow's results of operations in our income statement beginning September 1, 2005. The following summary unaudited pro forma consolidated results of operations for the years ended December 31, 2005 and 2004 reflect the combination of our historical income statements with Medicine Bow's, adjusted for certain effects of the acquisition and related funding. These pro forma results are prepared as if the acquisition had occurred as of the beginning of the periods presented and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

	Year Ended December 31,	
	2005[1]	2004
	(In millions, except per share amounts)	
Revenues	$3,398	$4,833
Net income	(623)	(958)
Basic and diluted loss per common share	(0.96)	(1.50)

[1] Excludes a $13 million pre-tax charge for change in control payments triggered at Medicine Bow as a result of the acquisition.

Divestitures

During 2006, 2005 and 2004, we sold a number of assets and investments in each of our business segments and corporate operations. The table and discussions below summarize the assets sold and proceeds from these sales:

	2006	2005	2004
		(In millions)	
Power	$ 531	$ 625	$ 884
Field Services	—	657	1,029
Exploration and Production	122	7	24
Pipelines	3	49	59
Corporate	2	121	16
Total continuing[(1)]	658	1,459	2,012
Discontinued	368	577	1,295
Total	$1,026	$2,036	$3,307

(1) Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items increased our sales proceeds by $15 million for the year ended December 31, 2006, and decreased our sales proceeds by $35 million and $85 million for the years ended December 31, 2005 and 2004.

Power. Assets sold consisted primarily of our interests in MCV and power plants in Brazil, Asia, and Central America in 2006; interests in our power contract restructuring entities and power plants in India and Korea in 2005; and interests in Utility Contract Funding and 31 domestic power plants in 2004.

Field Services. Assets sold consisted primarily of our investment in Enterprise and the Javelina natural gas processing and pipeline assets in 2005 and our investment in GulfTerra in 2004.

Exploration and Production, Pipelines, and Corporate. Assets sold consisted primarily of natural gas and oil properties in south Texas and various corporate assets in 2006; pipeline facilities and gathering systems located in the southeastern and western U.S. and Lakeside Technology Center in 2005; and Brazilian exploration and production acreage and various corporate assets in 2004.

In February 2007, we sold ANR, our Michigan storage assets, our 50 percent interest in Great Lakes Gas Transmission and a pipeline lateral located in the northeastern United States. Cash proceeds from these sales was approximately $3.7 billion. We expect to record a gain on these sales in 2007.

Discontinued Operations and Assets Held for Sale

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals to be disposed of by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these operations do not maintain separate cash balances, we reflect the net cash flows generated from these businesses as a contribution to our continuing operations in cash from continuing financing activities. The following is a description of our discontinued operations and summarized results of these operations for the periods ended December 31, 2006, 2005 and 2004. We also had assets held for sale of approximately $28 million as of December 31, 2006, which were sold in February 2007.

ANR and Related Operations. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission to TransCanada Corporation and TC Pipeline, LP for net cash proceeds of approximately $3.7 billion as further described above.

International Power Operations. In 2006, our Board of Directors approved the sale of our interest in Macae, a wholly owned power plant facility in Brazil. In 2005, our Board of Directors approved the sale of our Asian and Central American power asset portfolio. In 2005, we recognized approximately $499 million of impairments, net of minority interest based upon indications of the value we would receive upon the sale of the assets. During 2006, we completed the sale of all of our discontinued international power operations for net proceeds of approximately $368 million.

South Louisiana Gathering and Processing Operations. During 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. We completed the sale of these assets in 2005 for net proceeds of approximately $486 million and recorded a pre-tax gain of approximately $394 million.

Other. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. We completed the sale of substantially all of these properties in 2004 and 2005 for approximately $395 million. During 2003, the sales of our petroleum markets businesses and operations were approved. We completed the sale of these operations by the end of 2005.

Income Taxes on Discontinued Operations. For the years ended December 31, 2006, 2005 and 2004, we incurred income tax expense associated with our discontinued operations of $274 million, $179 million and $142 million resulting in an effective tax rate of approximately 126%, 216% and 63% for these years. These effective tax rates are significantly higher than the statutory rate of 35% primarily due to the following items:

- In 2006, we recorded approximately $188 million of deferred taxes upon agreeing to sell the stock of ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission. Prior to our decision to sell, we were only required to record deferred taxes on individual assets/liabilities and a portion of our investment in the stock of one of these companies;

- In 2005, impairments and operating losses of certain foreign investments for which no tax benefit was available, dividends from foreign subsidiaries taxable in the U.S. and state income taxes; and

- In 2004, impairments and operating losses of certain foreign investments, for which no tax benefit was available and state income taxes.

The summarized operating results and financial position data of our discontinued operations were as follows:

	ANR and Related Operations	International Power Operations	South Louisiana Gathering and Processing Operations	Other	Total
			(In millions)		
Year Ended December 31, 2006					
Revenues	$ 581	$ 149	$ —	$ —	$ 730
Costs and expenses	(334)	(159)	—	—	(493)
Gain (loss) on long-lived assets	—	(11)	5	—	(6)
Other income	63	3	—	—	66
Interest and debt expense	(65)	(14)	—	—	(79)
Income (loss) before income taxes	$ 245	$ (32)	$ 5	$ —	218
Income taxes					274
Loss from discontinued operations, net of income taxes					$ (56)
Year Ended December 31, 2005					
Revenues	$ 612	$ 207	$ 292	$ 127	$ 1,238
Costs and expenses	(372)	(216)	(264)	(182)	(1,034)
Gain (loss) on long-lived assets	—	(510)	394	2	(114)
Other income	62	13	—	12	87
Interest and debt expense	(68)	(26)	—	—	(94)
Income (loss) before income taxes	$ 234	$(532)	$ 422	$ (41)	83
Income taxes					179
Loss from discontinued operations, net of income taxes					$ (96)
Year Ended December 31, 2004					
Revenues	$ 506	$ 393	$ 265	$ 818	$ 1,982
Costs and expenses	(304)	(225)	(229)	(892)	(1,650)
Loss on long-lived assets	—	(30)	—	(58)	(88)
Other income	70	10	—	15	95
Interest and debt expense	(71)	(39)	—	(2)	(112)
Income (loss) before income taxes	$ 201	$ 109	$ 36	$(119)	227
Income taxes					142
Income from discontinued operations, net of income taxes					$ 85

	ANR and Related Operations	International Power Operations	South Louisiana Gathering and Processing Operations	Other	Total
			(In millions)		
December 31, 2006					
Assets of discontinued operations					
Accounts and notes receivable	$ 19	$ —	$—	$—	$ 19
Other current assets	757	—	—	—	757
Property, plant and equipment, net	3,357	—	—	—	3,357
Total assets	$4,133	$ —	$—	$—	$4,133
Liabilities of discontinued operations					
Accounts payable	$ 64	$ —	$—	$—	$ 64
Other current liabilities	160	—	—	—	160
Long-term debt	741	—	—	—	741
Deferred income taxes	852	—	—	—	852
Total liabilities	$1,817	$ —	$—	$—	$1,817
December 31, 2005					
Assets of discontinued operations					
Accounts and notes receivable	$ 90	$ 25	$—	$—	$ 115
Other current assets	30	204	—	—	234
Property, plant and equipment, net	3,235	351	—	—	3,586
Other non-current assets	711	3	—	—	714
Total assets	$4,066	$583	$—	$—	$4,649
Liabilities of discontinued operations					
Accounts payable	$ 94	$206	$—	$—	$ 300
Other current liabilities	47	216	—	—	263
Long-term debt	741	—	—	—	741
Deferred income taxes	859	—	—	—	859
Other non-current liabilities	69	—	—	—	69
Total liabilities	$1,810	$422	$—	$—	$2,232

3. (Gain) Loss on Long-Lived Assets

Our (gain) loss on long-lived assets from continuing operations consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets, including goodwill and other intangibles. Our asset impairments were primarily the result of asset sales, unfavorable contract negotiations related to the assets, and discontinuance of pipeline development projects based on changing economic conditions. For additional information on asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 2 and 18. During each of the three years ended December 31, our (gain) loss on long-lived assets was as follows:

	2006	2005	2004
		(In millions)	
Net realized (gain) loss	$ 2	$ 1	$ (16)
Asset impairments			
Power			
Brazilian assets	—	—	183
Domestic power assets	—	—	397
Turbines	—	18	1
Pipelines			
Pipeline development projects	16	46	—
Field Services			
Goodwill impairment	—	—	480
Other	—	9	23
Other	—	—	9
Total asset impairments	16	73	1,093
Loss on long-lived assets	18	74	1,077
Gain on sale of investments in unconsolidated affiliates, net of impairments	(6)	(91)	(124)
(Gain) loss on assets and investments	$12	$(17)	$ 953

4. Other Income and Other Expenses

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

	2006	2005	2004
		(In millions)	
Other Income			
Interest income	$138	$125	$ 88
Allowance for funds used during construction	31	31	22
Development, management and administrative services fees on power projects from affiliates	7	11	14
Foreign currency gain	—	36	14
Gain on sale of cost basis investments	47	40	—
Dividend income	14	19	—
Other	8	23	37
Total	$245	$285	$175
Other Expenses			
Foreign currency losses	$ 20	$ —	$ 26
Loss on early extinguishment of debt	26	29	12
Loss on sale of cost basis investments	12	—	—
Minority interest in consolidated subsidiaries	1	1	38
Other	8	17	18
Total	$ 67	$ 47	$ 94

5. Income Taxes

Pretax Income (Loss) and Income Tax Expense (Benefit). The tables below show our pretax income (loss) from continuing operations and the components of income tax expense (benefit) for each of the years ended December 31:

	2006	2005	2004
		(In millions)	
Pretax Income (Loss)			
U.S.	$442	$(872)	$ (952)
Foreign	80	35	(196)
	$522	$(837)	$(1,148)
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ 7	$ (13)	$ (17)
State	(15)	(37)	33
Foreign	19	22	8
	11	(28)	24
Deferred			
Federal	(46)	(372)	(133)
State	32	67	(8)
Foreign	(6)	2	1
	(20)	(303)	(140)
Total income taxes	$ (9)	$(331)	$ (116)

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

	2006	2005	2004
		(In millions, except rates)	
Income taxes at the statutory federal rate of 35%	$ 183	$(293)	$(402)
Increase (decrease)			
Audit settlements	(159)	(58)	—
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(35)	(36)	(17)
State income taxes, net of federal income tax effect	20	(16)	(1)
Sales and write-offs of foreign investments	(17)	(7)	14
Foreign income taxed at different rates	(13)	75	132
IRS interest refund	(11)	—	—
Valuation allowances	23	34	18
Non-deductible goodwill impairments	—	—	139
Non-taxable medicare reimbursements	(6)	(25)	—
Other	6	(5)	1
Income taxes	$ (9)	$(331)	$(116)
Effective tax rate	(2)%	40%	10%

In 2006 and 2005, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the conclusion of IRS audits. In 2006, the audits of The Coastal Corporation's 1998-2000 tax years and El Paso's 2001 and 2002 tax years were concluded which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. In 2005, we finalized The Coastal Corporation's IRS tax audits for years prior to 1998.

In 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to sales of our GulfTerra investment and impairments of certain of our foreign investments. The sale of GulfTerra resulted in a significant net taxable gain (compared to a lower book gain) and thus significant tax expense due to the non-deductibility of goodwill written off as a result of that transaction. The impact of this non-deductible goodwill increased our tax expense in 2004 by approximately $139 million. Additionally, we received no U.S federal income tax benefit on the impairment of certain of our foreign investments.

Deferred Tax Assets and Liabilities. The following are the components of our net deferred tax liability related to continuing operations as of December 31:

	2006	2005
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$2,736	$2,423
Investments in affiliates	555	205
Regulatory and other assets	53	302
Total deferred tax liability	3,344	2,930
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,560	1,098
State	214	204
Foreign	81	49
Environmental liability	144	147
Price risk management activities	284	573
Legal and other reserves	332	266
Other	424	574
Valuation allowance	(127)	(107)
Total deferred tax asset	2,912	2,804
Net deferred tax liability	$ 432	$ 126

Prior to 2004, we had not recorded U.S. deferred tax assets or liabilities on book versus tax basis differences for a substantial portion of our international investments based on our intent to indefinitely reinvest earnings from these investments outside the U.S. Based on sales negotiations on certain power assets in Asia, Central America, and India, however, we have received or expect to receive these sales proceeds within the U.S. As a result, during the years ended December 31, 2006, 2005 and 2004, we recorded U.S. deferred tax assets and liabilities on book versus tax basis differences in these investments. We also recorded U.S. deferred tax benefits on the sale of a power asset in India. As of December 31, 2006 and 2005, we have U.S. deferred tax assets of $45 million and $103 million and U.S. deferred tax liabilities of $2 million and $23 million related to these investments.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding the power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation, and an estimate of the taxes if earnings were to be repatriated is not practical. At December 31, 2006, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $112 million. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income.

Tax Credit and NOL Carryovers. As of December 31, 2006, we have U.S. federal alternative minimum tax credits of $326 million that carryover indefinitely, $1 million of general business credit carryovers for which the carryover periods end in various years from 2010 through 2022 and capital loss carryovers of $11 million for which the carryover period ends in 2008. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2006:

	Carryover Period				
	2007	**2008-2011**	**2012-2016**	**2017-2026**	**Total**
			(In millions)		
U.S. federal net operating loss	$ —	$ 16	$ 7	$3,626	$3,649
State net operating loss	182	1,013	496	999	2,690

We also had $182 million of foreign net operating loss carryovers and $56 million of foreign capital loss carryovers which carryover indefinitely. Usage of our U.S. federal carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

Valuation Allowances. Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. As part of our assessment, we consider future reversals of existing taxable temporary differences, primarily related to depreciation. In 2006, we also considered the gain we expected on the sale of ANR and related assets in our assessment. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

Other Tax Matters. The IRS is currently auditing El Paso's 2003 and 2004 tax years. We have recorded liabilities for tax contingencies associated with these audits, as well as for proceedings and examinations with other taxing authorities, which we believe are adequate. As these matters are finalized, we may be required to adjust our liability which could significantly increase or decrease our income tax expense and effective income tax rates in future periods.

6. Earnings Per Share

We calculated basic and diluted earnings per common share as follows for the three years ended December 31:

	2006		2005		2004	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)					
Income (loss) from continuing operations	$ 531	$ 531	$ (506)	$ (506)	$(1,032)	$(1,032)
Convertible preferred stock dividends	(37)	—	(27)	(27)	—	—
Income (loss) from continuing operations available to common stockholders	494	531	(533)	(533)	(1,032)	(1,032)
Discontinued operations	(56)	(56)	(96)	(96)	85	85
Cumulative effect of accounting changes, net of income taxes	—	—	(4)	(4)	—	—
Net income (loss) available to common stockholders	$ 438	$ 475	$ (633)	$ (633)	$ (947)	$ (947)
Weighted average common shares outstanding	678	678	646	646	639	639
Effect of dilutive securities:						
Options and restricted stock	—	4	—	—	—	—
Convertible preferred stock	—	57	—	—	—	—
Weighted average common shares outstanding and dilutive potential common shares	678	739	646	646	639	639
Earnings per common share:						
Income (loss) from continuing operations	$ 0.73	$ 0.72	$(0.82)	$(0.82)	$ (1.61)	$ (1.61)
Discontinued operations, net of income taxes	(0.08)	(0.08)	(0.15)	(0.15)	0.13	0.13
Cumulative effect of accounting changes, net of income taxes	—	—	(0.01)	(0.01)	—	—
Net income (loss)	$ 0.65	$ 0.64	$(0.98)	$(0.98)	$ (1.48)	$ (1.48)

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. These potentially dilutive securities consist of our employee stock options, restricted stock, convertible preferred stock issued in 2005, trust preferred securities, and zero coupon convertible debentures (which were paid off in April 2006). For the year ended December 31, 2006, certain employee stock options, our zero coupon convertible debentures and our trust preferred securities were antidilutive. For the year ended December 31, 2005 and 2004, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive. For a discussion of our capital stock activity, our stock-based compensation arrangements, and other instruments noted above, see Notes 15 and 16.

7. Fair Value of Financial Instruments

	As of December 31,			
	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$14,689	$15,487	$17,266	$17,607
Commodity-based price risk management derivatives	(395)	(395)	(1,416)	(1,416)
Interest rate and foreign currency derivatives	43	43	2	2
Investments	23	23	61	61

As of December 31, 2006 and 2005, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represented fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the interest rate. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. See Note 8 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities. Our investments primarily relate to available for sale securities and cost basis investments.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2006 and 2005. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options and swaps, other natural gas and power purchase and supply contracts, and derivatives from our historical energy trading activities. Finally, interest rate and foreign currency derivatives consist of swaps that are primarily designated as hedges of our interest rate and foreign currency risk on long-term debt.

	As of December 31,	
	2006	2005
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ 61	$ (653)
Other commodity-based derivative contracts	(456)	(763)
Total commodity-based derivatives[(1)]	(395)	(1,416)
Interest rate and foreign currency derivatives	43	2
Net liabilities from price risk management activities[(2)]	$(352)	$(1,414)

(1) Decrease is due primarily to the sale or assignment of a number of derivative contracts and significant changes in natural gas and oil prices during 2006.
(2) Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. We use commodity pricing data either obtained or derived from an independent pricing source and other assumptions about certain power and natural gas markets to develop price curves. The curves are then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discount these estimated settlement values using a LIBOR curve. We record valuation adjustments to reflect uncertainties associated with the estimates we use in determining fair value. Common valuation adjustments include those for market liquidity and those for the credit-worthiness of our contractual counterparties. During 2006 and 2005, we changed the independent pricing source that provided the pricing data we used in valuing certain of our commodity-based derivative contracts. These changes did not have a material impact on the fair value of our positions as of December 31, 2006, and 2005.

Derivatives Designated as Hedges

We engage in two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. When we enter into a derivative contract, we may designate the derivative as either a cash flow hedge or a fair value hedge, at which time we prepare the documentation required under SFAS No. 133. Hedges of cash flow exposure, which primarily relate to our natural gas and oil production hedges and interest rate risks on our long-term debt, are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to protect the fair value of a recognized asset, liability or firm commitment. Hedges of our interest rate and foreign currency exposure are designated as either cash flow hedges or fair value hedges based on whether the interest on the underlying debt is converted to either a fixed or floating interest rate. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur. Changes in the fair value of derivatives that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of the related hedged assets, liabilities or firm commitments. The ineffective portion of a hedge's change in fair value, if any, is recognized immediately in earnings as a component of operating revenues or interest and debt expense in our income statement. A discussion of each of our hedging activities is as follows:

Cash Flow Hedges. A majority of our commodity sales and purchases are at spot market or forward market prices. We use fixed price swaps and floor and ceiling contracts to limit our exposure to fluctuations in the commodity markets as well as fluctuations in foreign currency and interest rates with the objective of realizing a fixed cash flow stream from these activities. A summary of the impacts of our cash flow hedges included in accumulated other comprehensive income (loss), net of income taxes, as of December 31, 2006 and 2005 follows:

	Accumulated Other Comprehensive Income (Loss)		Estimated Income (Loss) Reclassification in 2007[1]	Final Termination Year
	2006	2005		
	(In millions)			
Commodity cash flow hedges				
Held by consolidated entities	$49	$(285)	$ 89	2012
Held by unconsolidated affiliates	(4)	(7)	(1)	2013
De-designated[2]	35	—	35	2007
Total commodity cash flow hedges	80	(292)	123	
Interest rate and foreign currency cash flow hedges				
Fixed rate	3	2	1	2015
De-designated	(3)	(4)	—	2009
Total foreign currency cash flow hedges	—	(2)	1	
Total cash flow hedges	$80	$(294)	$124	

(1) Reclassifications occur upon the physical delivery of the hedged commodity or if the forecasted transaction is no longer probable.

(2) During 2006, we removed the hedging designation on certain derivatives that hedged approximately 75 Tbtu and 154 MBbls of our natural gas and oil production in 2007.

For the years ended December 31, 2006, 2005 and 2004, we recognized a net gain of $10 million, and losses of $5 million and $1 million, net of income taxes, in our income (loss) from continuing operations related to the ineffective portion of our cash flow hedges.

Fair Value Hedges. We have fixed rate U.S. dollar and foreign currency denominated debt that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps to protect the value of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments and have recorded the fair value of these derivatives as a component of long-term debt and the related accrued interest. As of December 31, 2006 and 2005, these derivatives were as follows (amounts in millions):

Derivative	Weighted Average Rate	Debt		Price Risk Management Asset (Liability)[1]	
		2006	2005	2006	2005
Fixed-to-floating swaps	LIBOR + 4.18%	$440	$440	$(31)	$(30)
Fixed-to-floating cross currency swaps[2]	LIBOR + 4.24%	402	402	67	23
				$ 36	$ (7)

(1) We did not record any ineffectiveness related to our fair value hedges in 2004, 2005 or 2006.

(2) As of December 31, 2006 and 2005, these derivatives, when combined with our Euro denominated debt, converted 350 million Euro of our debt to $402 million.

Other Commodity-Based Derivatives.

Our other commodity-based derivatives primarily relate to derivative contracts not designated as hedges and other contracts associated with our historical trading activities.

Credit Risk

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

We use daily margining provisions in our financial contracts, most of our physical power agreements and our master netting agreements, which require a counterparty to post cash or letters of credit when the fair value of the contract exceeds the daily contractual threshold. The threshold amount is typically tied to the published credit rating of the counterparty. Our margining collateral provisions also allow us to terminate a contract and liquidate all positions if the counterparty is unable to provide the required collateral. Under our margining provisions, we are required to return collateral if the amount of posted collateral exceeds the amount of collateral required. Collateral received or returned can vary significantly from day to day based on the changes in the market values and our counterparty's credit ratings. Furthermore, the amount of collateral we hold may be more or less than the fair value of our derivative contracts with that counterparty at any given period. The following table presents a summary of the fair value of our derivative contracts, net of collateral and liabilities where a right of offset exists. It is presented by type of derivative counterparty in which we had net asset exposure as of December 31, 2006 and 2005:

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2006				
Energy marketers	$ 136	$ 81	$ —	$ 217
Natural gas and electric utilities	6	—	64	70
Commodity exchanges	321	—	—	321
Financial institutions and other	153	—	1	154
Net financial instrument assets[2]	616	81	65	762
Collateral held by us	(328)	(78)	(64)	(470)
Net exposure from derivative assets	$ 288	$ 3	$ 1	$ 292

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2005				
Energy marketers	$ 554	$110	$ —	$ 664
Natural gas and electric utilities	6	—	134	140
Commodity exchanges	533	—	—	533
Financial institutions and other	27	—	1	28
Net financial instrument assets[2]	1,120	110	135	1,365
Collateral held by us	(831)	(96)	(68)	(995)
Net exposure from derivative assets	$ 289	$ 14	$ 67	$ 370

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

We have approximately 54 counterparties as of December 31, 2006, most of which are energy marketers. Although most of our counterparties are not currently rated as below investment grade, if one of our counterparties fails to perform, we may recognize an immediate loss in our earnings, as well as additional financial impacts in the future delivery periods to the extent a replacement contract at the same prices and quantities cannot be established.

As of December 31, 2006, three counterparties, Deutsche Bank AG J. Aron & Company and Constellation Energy Commodities Group, Inc. comprised 39 percent, 18 percent and 16 percent of our net financial instrument asset exposure. As of December 31, 2005, two counterparties, Constellation Energy Commodities Group, Inc. and Duke Energy Trading and Marketing LLC, comprised 28 percent and 18 percent of our net financial instrument asset exposure. The concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

9. Regulatory Assets and Liabilities

Our regulatory assets and liabilities relate to our interstate pipeline subsidiaries and are included in other current and non-current assets and liabilities on our balance sheets. These balances are presented on our balance sheets on a gross basis and are recoverable over various periods. Below are the details of our regulatory assets and liabilities as of December 31:

	2006	2005
	(In millions)	
Current regulatory assets	$ 6	$ 4
Non-current regulatory assets		
Gross-up of deferred taxes on capitalized funds used during construction	106	96
Postretirement benefits	22	25
Unamortized net loss on reacquired debt	19	20
Under-collected state income tax	3	7
Other	21	16
Total non-current regulatory assets	171	164
Total regulatory assets	$177	$168
Current regulatory liabilities	$ 16	$ 9
Non-current regulatory liabilities		
Environmental liability	130	110
Cost of removal of offshore assets	12	48
Property and plant depreciation	70	41
Postretirement benefits	19	16
Plant regulatory liability	11	11
Excess deferred income taxes	6	6
Other	4	8
Total non-current regulatory liabilities	252	240
Total regulatory liabilities	$268	$249

10. Other Assets and Liabilities

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

	2006	2005
	(In millions)	
Other current assets		
Prepaid expenses	$ 72	$ 85
Restricted cash (Note 1)	8	92
Inventory	115	118
Deposits	60	—
Other	37	23
Total	$ 292	$ 318
Other non-current assets		
Pension, other postretirement and postemployment benefits (Note 14)	$ 332	$ 886
Notes receivable from affiliates	232	263
Restricted cash (Note 1)	123	168
Unamortized debt expenses	133	164
Regulatory assets (Note 9)	171	164
Long-term receivables	131	410
Other	173	215
Total	$1,295	$2,270
Other current liabilities		
Accrued taxes, other than income	$ 95	$ 95
Income taxes	17	58
Environmental, legal and rate reserves (Note 13)	560	174
Deposits	30	21
Pension and other postretirement benefit (Note 14)	30	35
Accrued lease obligations	56	43
Asset retirement obligations (Note 11)	89	31
Dividends payable	37	35
Accrued liabilities	26	36
Other	93	119
Total	$1,033	$ 647
Other non-current liabilities		
Environmental and legal reserves (Note 13)	$ 616	$1,004
Pension, other postretirement and postemployment benefits (Note 14)	294	224
Regulatory liabilities (Note 9)	252	240
Asset retirement obligations (Note 11)	154	178
Other deferred credits	159	183
Insurance reserves	118	132
Other	97	242
Total	$1,690	$2,203

11. Property, Plant and Equipment

Depreciable lives. The table below presents the depreciation method and depreciable lives of our property, plant and equipment:

	Method	Depreciable Lives (In years)
Regulated interstate systems	Composite	(1)
Non-regulated assets		
Natural gas and oil properties	(2)	(2)
Transmission and storage facilities	Straight-line	5-27
Gathering and processing systems	Straight-line	40
Transportation equipment	Straight-line	6
Buildings and improvements	Straight-line	4-49
Office and miscellaneous equipment	Straight-line	1-28

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

(2) Capitalized costs associated with proved reserves are amortized over the life of the reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated. See Note 1 for additional information.

Excess purchase cost. As of December 31, 2006 and 2005, TGP and EPNG have excess purchase costs associated with their acquisition. Total excess costs on these pipelines were approximately $2.5 billion and accumulated depreciation was approximately $0.4 billion and $0.3 billion at December 31, 2006 and 2005. These excess costs are being depreciated over the life of the pipeline assets to which the costs were assigned, and our related depreciation expense for each year ended December 31, 2006, 2005, and 2004 was approximately $42 million. We do not currently earn a return on these excess purchase costs from our rate payers.

Capitalized costs during construction. We capitalize a carrying cost on funds related to our construction of long-lived assets and reflect these as increases in the cost of the asset on our balance sheet. This carrying cost consists of (i) an interest cost on our debt that could be attributed to the assets being constructed, and (ii) in our regulated transmission business, a return on our equity, that could be attributed to the assets being constructed. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized are included as a reduction of interest expense in our income statements and was $41 million, $41 million and $35 million during the years ended December 31, 2006, 2005 and 2004. The equity portion is calculated using the most recent FERC approved equity rate of return. Equity amounts capitalized are included as other non-operating income on our income statement and were $28 million, $31 million and $22 million during the years ended December 2006, 2005 and 2004.

Construction work-in progress. At December 31, 2006 and 2005, we had approximately $1 billion of construction work-in-progress included in our property, plant and equipment.

Asset retirement obligations. We have legal obligations associated with the retirement of our natural gas and oil wells and related infrastructure, our natural gas pipelines and related transmission facilities and storage wells, as well as in our corporate headquarters building. We have obligations to plug wells when production on those wells is exhausted or we no longer plan to use them, and when we abandon them. Our legal obligations associated with our natural gas transmission facilities relate primarily to purging and sealing the pipelines if they are abandoned. We also have obligations to remove hazardous materials associated with our natural gas transmission facilities and in our corporate headquarters if these facilities are replaced or renovated. We accrue a liability for legal obligations based on an estimate of the timing and amount of their settlement. We are required to operate and maintain our natural gas pipeline and storage systems, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that the substantial majority of our natural gas pipeline and storage system assets have indeterminate lives. We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates ranging from six to eight percent and a projected inflation rate of 2.5 percent. Changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes primarily result from obtaining new information in our Exploration and Production segment about the timing of our obligations to plug our natural gas and oil wells and the costs to do so. In 2006, we also revised our estimates due primarily to the impacts of hurricanes Katrina and Rita. The net asset retirement liability as of December 31 reported on our balance sheet in other current and non-current liabilities, and the changes in the net liability for the years ended December 31, were as follows:

	2006	2005
	(In millions)	
Net asset retirement liability at January 1	$252	$309
Liabilities settled[1]	(48)	(92)
Accretion expense	19	27
Liabilities incurred	5	12
Changes in estimate	15	(12)
Adoption of FIN No. 47[2]	—	8
Net asset retirement liability at December 31	$243	$252

[1] Decrease is due primarily to the sale of certain domestic natural gas and oil properties in our Exploration and Production segment in 2005. See Note 2.

[2] We recorded a charge in 2005 of $4 million net of income taxes of $2 million as a cumulative effect of accounting change upon our adoption of FIN No. 47 (primarily related to our Pipelines segment and our corporate activities). If we had adopted the provisions of FIN No. 47 as of January 1, 2004, our net income for the years ended December 31, 2004 and 2005 would not have been materially affected.

12. Debt, Other Financing Obligations and Other Credit Facilities

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,360	$ 984
Long-term financing obligations	13,329	16,282
Total[1]	$14,689	$17,266

The following provides additional detail on our long-term financing obligations:

	2006	2005
Colorado Interstate Gas Company		
Notes, 5.95% through 6.85%, due 2015 through 2037	$ 700	$ 700
El Paso Corporation		
Notes, 6.375% through 10.75%, due 2007 through 2037	7,939	8,212
Zero coupon convertible debentures	—	611
$1.25 billion term loan, LIBOR plus 2.75%	—	1,225
$1.25 billion revolver, LIBOR plus 1.75% due 2009	200	—
El Paso Natural Gas Company		
Notes, 7.5% through 8.625%, due 2010 through 2032	1,115	1,115
El Paso Exploration & Production Company		
Senior note, 7.75%, due 2013	1,200	1,200
Revolving credit facility, variable due 2010	145	500
Southern Natural Gas Company		
Notes, 6.125% through 8.875%, due 2007 through 2032	1,200	1,200
Tennessee Gas Pipeline Company		
Notes, 6.0% through 8.375%, due 2011 through 2037	1,626	1,626
Other	310	323
	14,435	16,712
Other financing obligations		
Capital Trust I, due 2028	325	325
Coastal Finance I	—	300
	325	625
Subtotal	14,760	17,337
Less:		
Other, including unamortized discounts and premiums	71	71
Current maturities	1,360	984
Total long-term financing obligations, less current maturities[1]	$13,329	$16,282

(1) Excludes $741 and $967 million of debt related to our discontinued operations in 2006 and 2005.

Changes in Long-Term Financing Obligations. During 2006, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value Increase (Decrease)	Cash Received/(Paid)
			(In millions)	
Issuances				
EPEP	Revolving credit facility due 2010	Variable	$ 175	$ 175
El Paso	Revolving credit facility due 2009	LIBOR + 1.75%	200	200
	Increases through December 31, 2006		$ 375	$ 375
Repayments, repurchases, retirements and other				
Coastal Finance I	Trust originated preferred securities	8.375%	$ (300)	$ (300)
El Paso	Zero coupon convertible debentures	—	(615)	(615)
El Paso	Euro notes	5.75%	(26)	(26)
EPEP	Revolving credit facility	Variable	(530)	(530)
El Paso	Notes	6.50%-7.50%	(315)	(315)
Macae[1]	Non-recourse notes	Variable	(229)	(229)
El Paso	Term Loan	LIBOR + 2.75%	(1,225)	(1,225)
Other	Long-term debt	Various	59	(13)
	Decreases through December 31, 2006		$(3,181)	$(3,253)

(1) Included in liabilities related to discontinued operations on our balance sheet at December 31, 2005.

Prior to their redemption in 2006, we recorded accretion expense on our zero coupon debentures, which increased the principal balance of long-term debt each period. During the 2006 and 2005, the accretion recorded in interest expense was $4 million and $25 million. During 2006 and 2005, we redeemed $615 million and $236 million of our zero coupon convertible debentures, of which $110 million and $34 million represented increased principal due to the accretion of interest on the debentures. We account for these redemptions as financing activities in our statement of cash flows.

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

2007	$ 1,360
2008	655
2009	1,570
2010	1,392
2011	1,167
Thereafter	8,616
Total long-term financing obligations, including current maturities	$14,760

Approximately $600 million of our debt obligations are redeemable at the option of the holders in the first half of 2007, which is prior to its stated maturity date. As a result, these amounts are classified as current liabilities in our balance sheet as of December 31, 2006. Subsequent to this date, the holders of $300 million of these obligations did not exercise their redemption right and the debt will mature in 2027.

In addition, approximately $9 billion of our debt obligations (increasing to approximately $10 billion by the end of 2008) provide us the ability to call the debt prior its stated maturity date. If redeemed prior to their stated maturities, we will be required to pay a make-whole or fixed premium in addition to repaying the principal and accrued interest.

In February 2007, we launched a tender offer for certain of our outstanding debt obligations in conjunction with the closing of the sale of ANR and related assets.

Credit Facilities

Available Capacity Under Credit Agreements. As of December 31, 2006, we had available capacity under our credit agreements of approximately $1 billion. Of this amount, $0.4 billion is related to the $500 million revolving credit agreement of our subsidiary, EPEP and $0.6 billion is available under our $1.75 billion credit agreement and our $500 million unsecured revolving credit facility. In January 2007, we borrowed approximately $250 million under the EPEP revolving credit facility to fund the acquisition of additional natural gas and oil properties.

Credit Agreement Restructuring. In July 2006, we restructured our $3 billion credit agreement. As part of this restructuring, we entered into a new $1.75 billion credit agreement, consisting of a $1.25 billion three-year revolving credit facility and a $500 million five-year deposit letter of credit facility. In conjunction with the restructuring, we recorded a 2006 charge of approximately $17 million associated with unamortized financing costs on the previous credit agreement. El Paso and certain of its subsidiaries have guaranteed the $1.75 billion credit agreement, which is collateralized by our stock ownership in CIG, EPNG and TGP who are also eligible borrowers under the $1.75 billion credit agreement.

Under the $1.25 billion revolving credit facility which matures in July 2009, we can borrow funds at LIBOR plus 1.75% or issue letters of credit at 1.75% plus a fee of 0.15% of the amount issued. We pay an annual commitment fee of 0.375% on any unused capacity under the revolving credit facility. The terms of the $500 million deposit letter of credit facility provide for the ability to issue letters of credit or borrow amounts as revolving loans which mature in July 2011. We pay LIBOR plus 2.00% on any amounts borrowed under the deposit facility, 2.15% on letters of credit, and 2.10% on unused capacity.

Unsecured Revolving Credit Facility. We have a $500 million unsecured revolving credit facility that matures in July 2011 with a third party and a third party trust that provides for both borrowings and issuing letters of credit. We are required to pay fixed facility fees at a rate of 2.3% on the total committed amount of the facility. In addition, we will pay interest on any borrowings at a rate comprised of either LIBOR or a base rate.

EPEP Revolving Credit Facility. Under this $500 million revolving credit agreement, EPEP can borrow revolving loans or issue letters of credit through its maturity date in August 2010. Amounts borrowed are classified as long-term on our balance sheet and carry an interest rate of LIBOR plus a fixed percentage of 1.25% to 1.875% depending on utilization. The facility is collateralized by certain of our natural gas and oil properties.

Contingent Letter of Credit Facility. In January, 2007, El Paso entered into a $250 million unsecured contingent letter of credit facility that matures in March 2008. Letters of credit are available to us under the facility if the average NYMEX gas price strip for the remaining calendar months through March 2008 is equal to or exceeds $11.75 per MMBtu. The facility fee, if triggered, is 1.66% per annum.

Restrictive Covenants

$1.75 billion Revolving Credit Facility. Our covenants under the $1.75 billion revolving credit facility include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, dividend restrictions, cross default and cross-acceleration. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our credit agreement the most restrictive debt covenants and cross default provisions are:

(a) Our ratio of Debt to Consolidated EBITDA, each as defined in the credit agreement, shall not exceed 5.75 to 1 at anytime prior to June 30, 2007. Thereafter it shall not exceed 5.5 to 1 until June 29, 2008 and 5.25 to 1 from June 30, 2008 until maturity;

(b) Our ratio of Consolidated EBITDA, as defined in the credit agreement, to interest expense plus dividends paid shall not be less than 1.75 to 1 at anytime prior to December 31, 2006. Thereafter it shall not be less than 1.80 to 1 until June 29, 2008, and 2.00 to 1 from June 30, 2008 until maturity;

(c) EPNG, TGP and CIG cannot incur incremental Debt if the incurrence of this incremental Debt would cause their Debt to Consolidated EBITDA ratio, each as defined in the credit agreement, for that particular company to exceed 5.0 to 1; and

(d) the occurrence of an event of default and after the expiration of any applicable grace period, with respect to Debt in an aggregate principal amount of $200 million or more.

EPEP Revolving Credit Facility. EPEP's borrowings under this facility are subject to various conditions. The financial coverage ratio under the facility requires that EPEP's EBITDA, as defined in the facility, to interest expense not be less than 2.0 to 1, EPEP's debt to EBITDA, each as defined in the credit agreement, must not exceed 4.0 to 1, and EPEP's Collateral Coverage Ratio (as defined in the credit agreement) must exceed 1.5 to 1.

Other Restrictions and Provisions. In addition to the above restrictions and provisions, we and/or our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in our cash management program, and limitations on some of our subsidiaries' ability to prepay debt. Our most restrictive acceleration provision is $5 million and is associated with the indenture of one of our subsidiaries. This indenture states that should an event of default occur resulting in the acceleration of other debt obligations in excess of $5 million, the long-term debt obligation containing that provision could be accelerated. The acceleration of our debt would adversely affect our liquidity position and in turn, our financial condition.

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

Other Financing Arrangements

Capital Trusts. El Paso Energy Capital Trust I (Trust I), is a wholly owned business trust formed in March 1998 that issued 6.5 million of 4.75 percent trust convertible preferred securities for $325 million. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75 percent convertible subordinated debentures we issued, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We also have two wholly owned business trusts, El Paso Energy Capital Trust II and III (Trust II and III), under which we have not issued securities. We provide a full and unconditional guarantee of Trust I's preferred securities, and would provide the same guarantee if securities were issued under Trust II and III.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 percent, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I preferred security (equivalent to a conversion price of

$41.59 per common share). We have classified these securities as long-term debt and we have the right to redeem these securities at any time.

Non-Recourse Project Financings. Many of our subsidiaries and investments have debt obligations related to their costs of project construction or acquisition. Several of our projects have experienced events that have either constituted or could constitute an event of default under the loan agreements. This project financing debt is recourse only to the project company and assets (i.e. without recourse to El Paso). We do not believe any of these defaults, or other events that have led to or could lead to events of default at these projects, will have a material effect on us or our subsidiaries' financial statements based on the amounts we have recorded on our balance sheet for these projects and/or the current status of negotiations relating to these projects.

Letters of Credit. We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of December 31, 2006, we had outstanding letters of credit of approximately $1.4 billion. Included in this amount is $1.1 billion of letters of credit securing our recorded obligations related to price risk management activities.

13. Commitments and Contingencies

Legal Proceedings

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. The consolidated lawsuit alleges violations of federal securities laws against us and several of our current and former officers and directors. In November 2006, the parties executed a definitive settlement agreement in which the parties agreed to settle these class action lawsuits, subject to final court approval. Under the terms of the settlement, El Paso and its insurers will pay a total of $273 million to the plaintiffs. El Paso has contributed approximately $48 million and its insurers have contributed approximately $225 million into an escrow account pending final court approval of the settlement. An additional $12 million was separately contributed by a third party under the terms of the settlement.

ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, - III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging that our communication with participants in our Retirement Savings Plan included misrepresentations and omissions similar to those pled in the consolidated shareholder litigation that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). Formal discovery in this lawsuit is currently stayed. We have various insurance coverages for this lawsuit, subject to certain deductibles and co-pay obligations. We have established accruals for these matters which we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a purported class action lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit alleges various violations of ERISA and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before July 1, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. Tenneco retained the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. Pursuant to an agreement with the applicable union for Case employees, our liability for these benefits was subject to a cap, such that costs in excess of the cap are assumed by plan participants. In 2002, we and Case were sued by individual retirees in a federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation.* The suit alleges, among other things, that El Paso and Case violated ERISA and that they should be required to pay all amounts above the cap. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend and hold Case harmless for the amounts it would be required to pay. In separate rulings in 2004, the court ruled that, pending a trial on the merits, Case must pay the amounts incurred above the cap and that El Paso must reimburse Case for those payments. In January 2006, these rulings were upheld on appeal by the U.S. Court of

Appeals for the 6th Circuit. We will proceed with a trial on the merits with regard to the issues of whether the cap is enforceable and what degree of benefits have actually vested. Until this is resolved, El Paso will indemnify Case for any payments Case makes above the cap, which are currently about $1.8 million per month. We continue to defend the action and have filed for approval by the trial court various amendments to the medical benefit plans which would allow us to deliver the benefits to plan participants in a more cost effective manner. Although it is uncertain what plan amendments will ultimately be approved, the approval of plan amendments could reduce our overall costs and, as a result, could reduce our recorded obligation. We have established an accrual for this matter which we believe is adequate.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits have been filed against El Paso Marketing L.P. (EPM) that allege El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. The first cases have been consolidated in federal court in New York for all pre-trial purposes and are styled In re: Gas Commodity Litigation. In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. We have executed settlement an agreement with the plaintiffs, which is subject to court approval.

The second set of cases, involving similar allegations on behalf of commercial and residential customers, were transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada, *In re Western States Wholesale Natural Gas Antitrust Litigation*, dismissed and have been appealed. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include purported class action lawsuits styled *Leggett et al. v. Duke Energy Corporation et al.* (filed in Chancery Court of Tennessee in January 2005); *Ever-Bloom Inc. v. AEP Energy Services Inc. et al.* (filed in federal court for the Eastern District of California in June 2005); *Farmland Industries, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in July 2005); *Learjet, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in September 2005); *Breckenridge, et al v. Oneok Inc., et al.* (filed in state court in Denver County, Colorado in May 2006), *Missouri Public Service Commission v. El Paso Corporation et al* (filed in the circuit court of Jackson County, Missouri at Kansas City in October 2006) and *Arandell, et al v. Xcel Energy, et al*(filed in the circuit court of Dane County, Wisconsin in December 2006). The *Leggett* and *Farmland* cases have been dismissed. The *Arandell* and *Missouri Public Service* cases have been removed to federal court. The remaining cases have all been transferred to the MDL proceeding. Similar motions to dismiss have either been filed or are anticipated to be filed in these cases as well. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Gas Measurement Cases. A number of our subsidiaries were named defendants in actions that generally allege mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act, which has been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming. These complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands. In May 2005, a representative appointed by the court issued a recommendation to dismiss most of the actions. In October 2006, the U.S. District Judge issued an order dismissing all mismeasurement claims against all defendants. An appeal has been filed.

Similar allegations were filed in a set of actions initiated in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The plaintiffs currently seek certification of a class of royalty owners in wells on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. Motions for class certification have been briefed and argued in the proceedings and the parties are awaiting the court's ruling. The plaintiff seeks an unspecified amount of monetary damages in the form of additional royalty payments (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. Our costs and legal exposure related to these lawsuits and claim are not currently determinable.

MTBE. Certain of our subsidiaries used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of their gasoline. Certain subsidiaries have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. Some of our subsidiaries are among the defendants in 70 such lawsuits. These suits have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general, various water districts and a limited number of individual water customers, generally seek remediation of their groundwater, prevention of future contamination, damages, punitive damages, attorney's fees and court costs. Among other allegations, plaintiffs assert that gasoline containing MTBE is a defective product and that defendant refiners are liable in proportion to their market share. Our costs and legal exposure related to these lawsuits are not currently determinable.

Government Investigations and Inquiries

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We continue to cooperate with the SEC in its investigation related to such reserve revisions.

Iraq Oil Sales. Several government agencies have been investigating The Coastal Corporation's and El Paso's purchases of crude oil from Iraq under the United Nations' Oil for Food Program. These agencies include the U.S. Attorney for the Southern District of New York (SDNY), the SEC and the Office of Foreign Assets Control (OFAC). In February 2007, we entered into agreements with the SDNY, SEC , and OFAC to resolve their pending investigations of our participation in the Oil for Food Program. The agreements obligate us to pay approximately $8 million, with approximately $6 million intended to be ultimately transferred to a humanitarian fund for the benefit of the Iraqi people.

Other Government Investigations. We also continue to provide information and cooperate with the inquiry or investigation of the U.S. Attorney and the SEC in response to requests for information regarding price reporting of transactional data to the energy trade press and the hedges of our natural gas production.

Other Contingencies

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million annually over current tariff rates, new services and revisions to certain terms and conditions of existing services. On January 1, 2006, the rates became effective, subject to refund. In March 2006, the FERC issued an order that generally approved our proposed new services, which were implemented on June 1, 2006. In December 2006, EPNG filed settlement of this rate case with the FERC. The settlement provides benefits for both EPNG and its customers for a three-year period ending December 31, 2008. Only one party in the rate case contested the settlement. The administrative law judge has certified the settlement to the FERC finding that the settlement could be approved for all parties or in the alternative that the contesting party could be severed from the settlement. We have reserved sufficient amounts to meet EPNG's refund obligations under the settlement. Such refunds will be payable within 120 days after approval by the FERC.

Iraq Imports. In December 2005, the Ministry of Oil for the State Oil Marketing Organization of Iraq (SOMO) sent an invoice to one of our subsidiaries with regard to shipments of crude oil that SOMO alleged were purchased and paid for by Coastal in 1990. The invoices request an additional $144 million of payments for such shipments, along with an allegation of an undefined amount of interest. The invoice appears to be associated with cargoes that Coastal had purchased just before the 1990 invasion of Kuwait by Iraq. We have requested additional information from SOMO to further assist in our evaluation of the invoice and the underlying facts. In addition, we are evaluating our legal defenses, including applicable statute of limitation periods.

Navajo Nation. Approximately 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on lands held in trust by the United States for the benefit of the Navajo Nation. Our rights-of-way on lands crossing the Navajo Nation are the subject of a pending renewal application filed in 2005 with the Department of the Interior's Bureau of Indian Affairs. An interim agreement with the Navajo Nation expired at the end of December 2006. Negotiations on the terms of the long-term agreement are continuing. In addition, we continue to preserve other legal, regulatory and legislative alternatives, which includes continuing to pursue our application with the Department of the Interior for renewal of our rights-of-way on Navajo Nation lands. It is uncertain whether our negotiation, or other alternatives, will be successful, or if successful, what the ultimate cost will be of obtaining the rights-of-way and whether we will be able to recover these costs in our rates.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of our outstanding legal and other contingent matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters, including those discussed above, cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2006, we had approximately $548 million accrued, net of related insurance receivables, for outstanding legal and other contingent matters. We have deposited $60 million to an escrow account for the shareholder litigation.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2006, we have accrued approximately $314 million, which has not been reduced by $31 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $305 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $9 million for related environmental legal costs. Of the $314 million accrual, $28 million was reserved for facilities we currently operate and $286 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $314 million to approximately $532 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($27 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($287 million to $505 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. Our recorded liabilities reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	December 31, 2006	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 28	$ 35
Non-operating	252	439
Superfund	34	58
Total	$314	$532

Below is a reconciliation of our accrued liability from January 1, 2006 to December 31, 2006 (in millions):

Balance as of January 1, 2006	$348
Additions/adjustments for remediation activities	30
Payments for remediation activities	(64)
Balance as of December 31, 2006	$314

For 2007, we estimate that our total remediation expenditures will be approximately $84 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $21 million in the aggregate for the years 2007 through 2011. These expenditures primarily relate to compliance with clean air regulations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 53 active sites under the CERCLA or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements, which provide for payment of our allocable share of remediation costs. As of December 31, 2006, we have estimated our share of the remediation costs at these sites to be between $34 million and $58 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Commitments, Purchase Obligations and Other Matters

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space, operating facilities and office and operating equipment. The terms of the agreements vary from 2007 until 2053. As of December 31, 2006, our total commitments under non-cancellable operating leases were approximately $98 million which have not been reduced by minimum sublease rentals of approximately $4 million due in the future under noncancelable subleases. Minimum annual rental commitments under our operating leases at December 31, 2006, were as follows:

Year Ending December 31,	Operating Leases
	(In millions)
2007	$66
2008	10
2009	7
2010	3
2011	1
Thereafter	11
Total	$98

Our lease obligations in the table above significantly decrease after 2007 based upon the expiration of certain lease payments made in accordance with the termination agreement signed in 2005 related to consolidating our Houston-based operations into one location. Rental expense on our lease obligations for the years ended December 31, 2006, 2005, and 2004 was $43 million, $53 million and $90 million, which includes $27 million and $80 million in 2005 and 2004 related to consolidating our Houston-based operations.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnification for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

As of December 31, 2006, we had recorded obligations of $71 million related to our guarantees and indemnification arrangements. These arrangements had a total stated value of approximately $376 million, for which we are indemnified by third parties for $18 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 12. Included in the above stated value of $376 million is approximately $120 million associated with tax matters, related interest and other indemnifications arising out of the sale of our Macae power facility.

In addition to the exposures described above, a trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits being paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $379 million associated with our estimated exposure under this matter as of December 31, 2006. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2006, we had firm commitments under transportation and storage capacity contracts of $400 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of $540 million.

We also hold cancelable easements or right-of-way arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems. Currently, our obligation under these easements is not material to the results of our operations. However, we are currently negotiating a long-term right-of-way agreement with the Navajo Nation which could result in a significant commitment by us (see *Navajo Nation* above).

14. Retirement Benefits

Overview of Retirement Benefits

Pension Benefits. Our primary pension plan is a defined benefit plan that covers substantially all of our U.S. employees and provides benefits under a cash balance formula. Certain employees who participated in the prior pension plans of El Paso, Sonat or Coastal receive the greater of cash balance benefits or transition benefits under the prior plan formulas. We do not anticipate making any contributions to this pension plan in 2007.

In addition to our primary pension plan, we maintain a Supplemental Executive Retirement Plan (SERP) that provides additional benefits to selected officers and key management. The SERP provides benefits in excess of certain IRS limits that essentially mirror those in the primary pension plan. We also maintain two other pension plans that are closed to new participants which provide benefits to former employees of our previously discontinued coal and convenience store operations. The SERP and the frozen plans together are referred to below as other pension plans. We also participate in several multi-employer pension plans for the benefit of our former employees who were union members. Our contributions to these plans during 2006, 2005 and 2004 were not material. We expect to contribute $5 million to the SERP and $3 million to the frozen plans in 2007.

During 2004, we recognized a $4 million curtailment benefit in our pension plans due to a reduction in the number of employees that participate in our pension plan. The reduction resulted from asset sales and the severance of employees.

Retirement Savings Plan. We maintain a defined contribution plan covering all of our U.S. employees. We match 75 percent of participant basic contributions up to 6 percent of eligible compensation and can make additional discretionary matching contributions. Amounts expensed under this plan were approximately $35 million, $30 million and $16 million for the years ended December 31, 2006, 2005 and 2004.

Other Postretirement Benefits. We provide postretirement medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent actual OPEB costs for our regulated pipeline companies differ from the amounts recovered in rates, a regulatory asset or liability is recorded. We expect to contribute $42 million to our postretirement plans in 2007. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs, and we reserve the right to change these benefits. We will retain the other postretirement benefit plans associated with the retirees of ANR after the sale of these operations in 2007.

Pension and Other Postretirement Benefits. On December 31, 2006, we adopted the recognition provisions of SFAS No. 158, and upon adoption we reflected the assets and liabilities related to our pension and other postretirement benefit plans based on their funded or unfunded status and all actuarial deferrals were reclassified as a component of accumulated other comprehensive income. The adoption of this standard decreased our other non-current assets by $601 million, our other non-current deferred tax liabilities by $210 million, and our accumulated other comprehensive income by $391 million.

The table below provides additional information related to our pension and other postretirement plans as of September 30, our measurement date, for our obligations and plan assets and as of December 31 for the balance sheet amounts:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In millions)			
Projected benefit obligation/accumulated postretirement benefit obligation	$2,157	$2,235	$494	$527
Fair value of plan assets	2,382	2,350	276	251
Current benefit liability	5	—	25	35
Non-current benefit liability	52	77	228	215
Non-current benefit asset	285	918	44	—
Accumulated other comprehensive income (loss), net of income taxes	(450)	(49)	15	—

Our accumulated benefit obligation for our defined benefit pension plans was $2,148 million and $2,216 million as of December 31, 2006 and 2005. For those pension plans whose accumulated benefit obligations exceeded the fair value of plan assets, our projected benefit obligation and accumulated benefit obligation was $167 million as of December 31, 2006 and $176 million as of December 31, 2005 and the fair value of our plan assets was $110 million and $99 million as of December 31, 2006 and 2005.

The accumulated postretirement benefit obligation and fair value of plan assets associated with our other postretirement benefit plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets was $320 million and $67 million as of December 31, 2006 and $374 million and $84 million as of December 31, 2005.

Our accumulated other comprehensive income includes approximately $10 million of unamortized prior service costs, net of tax. We anticipate that approximately $25 million of our accumulated other comprehensive loss, net of tax, will be recognized as a part of our net periodic benefit cost in 2007.

Change in Benefit Obligation, Plan Assets and Funded Status. Our benefits are presented and computed as of and for the twelve months ended September 30:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(In millions)			
Change in benefit obligation[1]:				
Benefit obligation — beginning of period	$2,235	$2,118	$ 527	$ 541
Service cost	17	22	11	1
Interest cost	118	121	26	29
Participant contributions	—	—	34	34
Actuarial loss (gain)	(37)	178[2]	(35)	(5)
Benefits paid	(176)	(203)	(69)	(73)
Other	—	(1)	—	—
Benefit obligation — end of period	$2,157	$2,235	$ 494	$ 527
Change in plan assets:				
Fair value of plan assets at beginning of period	$2,350	$2,289	$ 251	$ 220
Actual return on plan assets[3]	192	255	19	20
Employer contributions	16	9	41	50
Participant contributions	—	—	34	34
Benefits paid	(176)	(203)	(69)	(73)
Administrative expenses	—	—	—	—
Fair value of plan assets at end of period	$2,382	$2,350	$ 276	$ 251
Reconciliation of funded status:				
Fair value of plan assets at September 30	$2,382	$2,350	$ 276	$ 251
Less: Benefit obligation — end of period	2,157	2,235	494	527
Funded status at September 30	225	115	(218)	(276)
Fourth quarter contributions and income	3	2	9	11
Unrecognized net actuarial loss[4]	—	733	—	20
Unrecognized prior service cost[4]	—	(9)	—	(5)
Net asset (liability) at December 31	$ 228	$ 841	$(209)	$(250)

(1) Benefit obligation in the table above refers to the projected benefit obligation for our pension plans and accumulated postretirement benefit obligation for our postretirement plans.

(2) Increase is due primarily to changes in our discount rate and mortality assumptions in 2005.

(3) We defer the difference between our actual return on plan assets and our expected return over a three year period, after which they are considered for inclusion in net benefit expense or income. Our deferred actuarial gains and losses are recognized only to the extent that all of our remaining unrecognized actual gains and loses exceed the greater of 10 percent of our projected benefit obligations or market related value of plan assets.

(4) Amounts were reclassified to accumulated other comprehensive income upon the adoption of SFAS No. 158 in 2006.

Expected Payment of Future Benefits. As of December 31, 2006, we expect the following payments under our plans:

Year Ending December 31,	Pension Benefits	Other Postretirement Benefits[1]
	(In millions)	
2007	$ 168	$ 48
2008	168	47
2009	166	45
2010	166	44
2011	165	43
2012-2016	802	193
Total	$1,635	$420

[1] Includes a reduction in each of the years presented for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

Components of Net Benefit Cost. For each of the years ended December 31, the components of net benefit cost are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
	(In millions)					
Service cost	$ 17	$ 22	$ 31	$ 11	$ 1	$ 1
Interest cost	118	121	121	26	29	34
Expected return on plan assets	(175)	(168)	(187)	(14)	(12)	(11)
Amortization of net actuarial loss	55	69	47	—	—	4
Amortization of transition obligation	—	—	—	—	8	8
Amortization of prior service cost[1]	(2)	(2)	(3)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	—	—	(4)	—	—	—
Other	—	7	—	(2)	—	—
Net benefit cost	$ 13	$ 49	$ 5	$ 20	$ 25	$ 35

[1] As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

Actuarial Assumptions and Sensitivity Analysis. Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit costs of our pension and other postretirement plans for 2006, 2005 and 2004:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
		(Percent)			(Percent)	
Assumptions related to benefit obligations at September 30:						
Discount rate	5.75	5.50		5.50	5.25	
Rate of compensation increase	4.00	4.00				
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	5.50	5.75	6.00	5.25	5.75	6.00
Expected return on plan assets[1]	8.00	8.00	8.50	8.00	7.50	7.50
Rate of compensation increase	4.00	4.00	4.00			

[1] The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 26 percent to 27 percent on other postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio.

Actuarial estimates for our other postretirement benefit plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.3 percent, gradually decreasing to 5.0 percent by the year 2015. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects as of September 30:

	2006	2005
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 1	$ 1
Accumulated postretirement benefit obligation	18	20
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (1)	$ (1)
Accumulated postretirement benefit obligation	(15)	(18)

Plan Assets. The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

	Pension Plans			Other Postretirement Plans		
Asset Category	Target	Actual 2006	Actual 2005	Target	Actual 2006	Actual 2005
		(Percent)			(Percent)	
Equity securities[1]	60	66	65	65	63	61
Debt securities	40	33	34	35	33	32
Other	—	1	1	—	4	7
Total	100	100	100	100	100	100

[1] During 2005, we liquidated all of the El Paso common stock included in plan assets.

The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

Other Matters. During the fourth quarter of 2005, we recorded an increase to our legal reserves of approximately $350 million associated with a closed group of retirees of the Case Corporation increasing our total liability to approximately $379 million at December 31, 2006. A trial court ruled, which was upheld on appeal, that we are required to indemnify Case for benefits paid to these retirees. We estimated our liability under this ruling utilizing actuarial methods similar to those used in estimating our obligations associated with our other postretirement benefit plans; however, these legal reserves are not included in the disclosures related to our pension and other postretirement benefits above. For a further discussion of this matter, see Note 13.

15. Stockholders' Equity

Common Stock. In May 2006, we issued 35.7 million shares of common stock for net proceeds of approximately $500 million. In 2005, we issued approximately 13.6 million shares of common stock to the remaining holders of $272 million of notes which originally formed a portion of our equity security units in settlement of their commitment to purchase the shares. In 2004, we issued 26.4 million shares to satisfy our obligations under the Western Energy Settlement.

Convertible Perpetual Preferred Stock. In April 2005, we issued $750 million of convertible perpetual preferred stock. Dividends on the preferred stock are declared quarterly at the rate of 4.99% per annum if approved by our Board of Directors and dividends accumulate if not paid. Each share of the preferred stock is convertible at the holder's option, at any time, subject to adjustment, into 76.7754 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately $13.03 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or adjustments to the current rate of dividends on our common stock. We will be able to cause the preferred stock to be converted into common stock after five years if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds of $723 million from the issuance of the preferred stock, together with cash on hand, was used to prepay our Western Energy Settlement of approximately $442 million and to redeem all of the 6 million outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, EPTP for approximately $300 million.

Dividends. The table below shows the amount of dividends paid and declared (in millions, except per share amounts).

	Common Stock ($0.16/share)	Convertible Preferred Stock (4.99%/year)
Amount paid in 2006	$108	$37
Amount paid in January 2007	$ 27	$ 9
Declared in 2007:		
Date of declaration	February 14, 2007	February 14, 2007
Date payable	April 2, 2007	April 2, 2007
Payable to shareholders on record	March 2, 2007	March 15, 2007

Dividends on our common stock are treated as reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common and preferred stock in 2006 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

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 aside 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 restriction 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.

Accumulated Other Comprehensive Income. The following table provides the components of our accumulated other comprehensive income (loss) as of December 31:

	2006	2005
Cash flow hedges (see Note 8)	$ 80	$(294)
Pension and other postretirement benefits (see Note 14)	(435)	(49)
Investments available for sale	12	15
Currency translation adjustment	—	(4)
Total accumulated other comprehensive loss, net of income taxes	$(343)	$(332)

16. Stock-Based Compensation

Under our stock-based compensation plans, we may issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. We are authorized to grant awards of approximately 42.5 million shares of our common stock under our current plans, which includes 35 million shares under our employee plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At December 31, 2006, approximately 35 million shares remain available for grant under our current plans. In addition, we have approximately 22 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

Non-Qualified Stock Options. We grant non-qualified stock options to our employees with an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally vest in equal amounts over three years from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the year ended December 31, 2006 is presented below:

	# Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2005	28,083,485	$37.12		
Granted	2,348,982	$12.32		
Exercised	(716,630)	$ 7.77		
Forfeited or canceled	(1,054,935)	$11.23		
Expired	(4,525,460)	$43.47		
Outstanding at December 31, 2006	24,135,442	$35.52	4.95	$53
Vested at December 31, 2006 or expected to vest in the future	23,806,801	$35.87	4.91	$52
Exercisable at December 31, 2006	17,562,622	$45.00	3.71	$20

Total compensation cost related to non-vested option awards not yet recognized at December 31, 2006 was approximately $10 million, which is expected to be recognized over a weighted average period of 11 months. Options exercised during the year ended December 31, 2006 had a total intrinsic value of approximately $5 million, generated $6 million of cash proceeds and did not generate any significant associated income tax benefit. The total intrinsic value, cash received and income tax benefit generated from option exercises was not material during the years ended December 31, 2005 and 2004.

Fair Value Assumptions. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management's best estimate at the time of grant. For the years ended December 31, 2006, 2005 and 2004 the weighted average grant date fair value per share of options granted was $4.89, $3.88 and $2.69. Listed below is the weighted average of each assumption based on grants in each fiscal year:

	2006	2005	2004
Expected Term in Years	6.0	4.8	5.4
Expected Volatility	38%	42%	45%
Expected Dividends	1.3%	1.5%	2.1%
Risk-Free Interest Rate	4.9%	3.7%	3.7%

We estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and our historical stock price volatility over the expected term, adjusted for certain time periods that we believe are not representative of future stock performance. Prior to January 1, 2006, we estimated expected volatility based primarily on adjusted historical stock price volatility. Effective January 1, 2006, we adopted the provisions of SEC Staff Accounting Bulletin No. 107 and estimate the expected term of our option awards based on the vesting period and average remaining contractual term.

Restricted Stock. We may grant shares of restricted common stock, which carry voting and dividend rights, to our officers and employees. Sale or transfer of these shares is restricted until they vest. We currently have outstanding and grant time-based restricted stock and performance-based restricted share awards. The fair value of our time-based restricted shares is determined on the grant date and these shares generally vest in equal amounts over three years from the date of grant. A summary of the changes in our non-vested restricted shares for each fiscal years are presented below:

Nonvested Shares	# Shares	Weighted Average Grant Date Fair Value per Share
Nonvested at December 31, 2005	3,916,030	$10.83
Granted	2,226,625	$13.09
Vested	(1,904,640)	$12.21
Forfeited	(498,795)	$11.02
Nonvested at December 31, 2006	3,739,220	$11.44

The weighted average grant date fair value per share for restricted stock granted during 2006, 2005 and 2004 was $13.09, $10.78 and $8.63. The total fair value of shares vested during 2006, 2005 and 2004 was $23.6 million, $14.3 million and $6.7 million.

During 2006, 2005 and 2004, we recognized approximately $17 million, $18 million and $23 million of pre-tax compensation expense, capitalized approximately $2 million in each year as part of fixed assets and recorded $6 million, $6 million and $8 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2006 was approximately $22 million, which is expected to be recognized over a weighted average period of 11 months. Upon adoption of SFAS No. 123(R), we recorded a cumulative effect of a change in accounting principle of less than $1 million as a result of estimating forfeitures for restricted stock on the date of grant as compared to recognizing forfeitures as they occur. We also reclassified unearned compensation as additional paid-in capital on our balance sheet as required by SFAS No. 123(R).

Employee Stock Purchase Plan. In July 2005, we reinstated our employee stock purchase plan under Section 423 of the Internal Revenue Code. The amended and restated plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of SFAS No. 123(R). Shares issued under this plan were insignificant during 2006, 2005 and 2004.

17. Business Segment Information

As of December 31, 2006, our business consists of Pipelines, Exploration and Production, Marketing and Power segments. Prior to 2006, we also had a Field Services segment. We have reclassified certain operations as discontinued operations for all periods presented (see Notes 1 and 2). Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions, as well as other miscellaneous businesses and various other contracts and assets, all of which are immaterial. A further discussion of each segment follows.

Pipelines. Provides natural gas transmission, storage, and related services, primarily in the United States. As of December 31, 2006, we conducted our activities primarily through eight wholly owned and five partially owned interstate transmission systems along with five underground natural gas storage entities and an LNG terminalling facility. In February 2007, we sold ANR, our Michigan storage facilities and our 50 percent interest in Great Lakes Gas Transmission.

Exploration and Production. Engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States, Brazil and Egypt.

Marketing. Focuses on marketing and managing the price risks associated with our natural gas and oil production as well as the management of our remaining historical trading portfolio.

Power. Primarily consists of our remaining international power assets. Historically, this segment also had domestic power activities. We have completed the sale of our domestic power facilities and sold or announced the sale of substantially all of our international operations, except for Brazil. Our primary focus within the Power segment is to manage the risks associated with our remaining assets in Brazil.

Prior to January 1, 2006 we had a Field Services segment which conducted midstream activities. We have disposed of substantially all of the assets in this segment.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2006, 2005 and 2004.

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 as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense (iv) distributions on preferred interests of consolidated subsidiaries and (v) preferred dividends. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

	2006	2005	2004
		(In millions)	
Segment EBIT	$ 1,838	$ 979	$ 591
Corporate and other	(88)	(521)	(217)
Interest and debt expense	(1,228)	(1,286)	(1,497)
Distributions on preferred interests of consolidated subsidiaries	—	(9)	(25)
Income taxes	9	331	116
Income (loss) from continuing operations	$ 531	$ (506)	$(1,032)

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

	As of or for the Year Ended December 31, 2006					
	Segment					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
			(In millions)			
Revenue from external customers						
Domestic	$ 2,331	$ 645[2]	$ 1,012	$ 4	$ 116	$ 4,108
Foreign	10	32	131	—	—	173
Intersegment revenue	61	1,177[2]	(1,201)	2	(39)	—
Operation and maintenance	728	410	28	54	99	1,319
Depreciation, depletion, and amortization	370	645	4	2	26	1,047
Loss on long-lived assets	15	—	—	3	—	18
Earnings from unconsolidated affiliates	90	10	—	45	—	145
EBIT	1,187	640	(71)	82	(88)	1,750
Discontinued operations, net of income taxes	118	—	—	(27)	(147)	(56)
Assets of continuing operations[3]						
Domestic	13,071	5,858	1,115	—	1,950	21,994
Foreign[4]	34	404	28	618	50	1,134
Capital expenditures and investments in and advances to unconsolidated affiliates, net[5]	1,023	1,113	—	(44)	14	2,106
Total investments in unconsolidated affiliates	757	729	—	221	—	1,707

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $37 million and an operation and maintenance expense elimination of $13 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production.

(3) Excludes assets of discontinued operations of $4,133 million (see Note 2).

(4) Of total foreign assets, approximately $362 million relates to property, plant and equipment, and approximately $0.7 billion relates to investments in and advances to unconsolidated affiliates.

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

	As of or for the Year Ended December 31, 2005						
	Segments						
	Pipelines	Exploration and Production	Marketing	Power	Field Services	Corporate[1] and Other	Total
			(In millions)				
Revenue from external customers							
Domestic	$ 2,094	$ 466[2]	$ 411	$ 71	$ 96	$ 85	$ 3,223
Foreign	7	54[2]	3	—	—	—	64
Intersegment revenue	70	1,267[2]	(1,210)	11	27	(93)	72[3]
Operation and maintenance	737	383	54	89	27	571	1,861
Depreciation, depletion, and amortization	343	612	4	2	3	42	1,006
(Gain) loss on long-lived assets	35	—	—	33	10	(4)	74
Earnings (losses) from unconsolidated affiliates	100	19	—	(139)	301	—	281
EBIT	924	696	(837)	(89)	285	(521)	458
Discontinued operations, net of income taxes	154	9	—	(476)	251	(34)	(96)
Assets of continuing operations[4]							
Domestic	12,363	5,215	3,786	70	99	4,081	25,614
Foreign[5]	26	355	33	1,106	—	57	1,577
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[6]	780	1,851	—	5	8	14	2,658
Total investments in unconsolidated affiliates	734	761	—	670	—	—	2,165

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $91 million and an operation and maintenance expense elimination of $2 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $4,649 million.

(5) Of total foreign assets, approximately $324 million relates to property, plant and equipment and approximately $1.0 billion relates to investments in and advances to unconsolidated affiliates.

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

	As of or for the Year Ended December 31, 2004						
	Segments						
	Pipelines	Exploration and Production	Marketing	Power	Field Services	Corporate[(1)] and Other	Total
				(In millions)			
Revenue from external customers							
Domestic	$ 2,048	$ 535[(2)]	$ 697	$ 241	$938	$ 133	$ 4,592
Foreign	9	26[(2)]	2	67	—	15	119
Intersegment revenue	88	1,174[(2)]	(1,207)	94	159	(236)	72[(3)]
Operation and maintenance	632	365	53	240	74	201	1,565
Depreciation, depletion, and amortization	329	548	13	13	8	51	962
(Gain) loss on long-lived assets	(1)	8	—	569	507	(6)	1,077
Earnings (losses) from unconsolidated affiliates	106	4	—	(249)	618	—	479
EBIT	1,059	734	(539)	(747)	84	(217)	374
Discontinued operations, net of income taxes	128	(36)	—	51	20	(78)	85
Assets of continuing operations[(4)]							
Domestic	11,851	3,714	2,372	982	518	4,439	23,876
Foreign[(5)]	58	366	32	1,572	—	96	2,124
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[(6)]	895	728	—	26	(15)	10	1,644
Total investments in unconsolidated affiliates	708	6	—	1,225	305	6	2,250

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of $236 million and an operation and maintenance expense elimination of $25 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

(4) Excludes assets of discontinued operations of $5,398 million.

(5) Of total foreign assets, approximately $435 million relates to property, plant and equipment and approximately $1.5 billion relates to investments in and advances to unconsolidated affiliates.

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

18. Investments in, Earnings from and Transactions with Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. Our income statement typically reflects (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments and other adjustments recorded by us.

Our investment balance differs from the underlying net equity in our investments due primarily to purchase price adjustments and impairment charges recorded by us. As of December 31, 2006 and 2005, our investment balance exceeded the net equity in the underlying net assets of these investments by $409 million and $378 million due to these items. The largest of our purchase price adjustments is related to our investment in Four Star which we acquired in 2005. We generally amortize and assess the recoverability of this amount based on the development and production of the underlying proved natural gas and oil reserves of Four Star. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the years ended December 31:

	Net Ownership Interest		Investment		Earnings (Losses) from Unconsolidated Affiliates		
	2006	2005	2006	2005	2006	2005	2004
	(Percent)		(In millions)		(In millions)		
Domestic:							
Four Star[1]	43	43	$ 723	$ 754	$ 10	$ 19	$ —
Citrus	50	50	597	596	62	66	65
Enterprise Products Partners[2]	—	—	—	—	—	183	6
GulfTerra Energy Partners[2]	—	—	—	—	—	—	601
Midland Cogeneration Venture[2]	—	44	—	—	13	(162)	(171)
Javelina[2]	—	—	—	—	—	121	15
Other Domestic Investments	various	various	36	47	3	17	22
Total domestic			1,356	1,397	88	244	538
Foreign:							
Araucaria Power[2]	—	60	—	187	2	—	—
Bolivia to Brazil Pipeline	8	8	105	96	11	20	24
San Fernando Pipeline	50	50	57	53	16	14	13
Habibullah Power[3][4]	50	50	17	16	1	(13)	(46)
Manaus/Rio Negro[5]	100	100	96	114	17	19	—
Saba Power Company[3]	94	94	—	—	—	(7)	(51)
Porto Velho[4]	50	50	(34)	(32)	2	(16)	(6)
Korea Independent Energy Corporation[2]	—	—	—	—	—	127	22
EGE Itabo[2]	—	25	—	24	1	(58)	1
Other Foreign Investments[4]	various	various	110	310	7	(49)	(16)
Total foreign			351	768	57	(37)	(59)
Total investments in unconsolidated affiliates			$1,707	$2,165			
Total earnings from unconsolidated affiliates					$145	$ 281	$ 479

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $54 million and $20 million during 2006 and 2005.

(2) We sold our interests in these investments.

(3) We have received approval from our Board of Directors to sell our interest in these investments, substantially all of which are targeted to close in the first half of 2007.

(4) As of December 31, 2006 and 2005, we had outstanding advances and receivables of $413 million and $385 million related to our foreign investments of which $25 million and $37 million related to our investment in Habibullah Power, $350 million and $331 million relate to our investment in Porto Velho, and the remainder in our other foreign investments. We recognized interest income on these outstanding advances and receivables of approximately $46 million, $47 million and $44 million in 2006, 2005 and 2004.

(5) We deconsolidated these 100% owned investments in January 2005 upon entering into an agreement that will transfer ownership of these plants to the power purchaser in January 2008.

Impairment charges and gains and losses on sales of equity investments are included in earnings from unconsolidated affiliates. During 2006, 2005 and 2004, our impairments and gains and losses were primarily a result of our decision to sell a number of these investments or were based on declines in their fair value of the investments due to changes in economics of the investments' underlying contracts, or the markets they serve. These realized gains (losses) consisted of the following:

Investment or Group	2006	2005	2004
		(In millions)	
Midland Cogeneration Venture[1]	$13	$(162)	$(161)
Asia power investments	(8)	(64)	(182)
Central and South American power investments	1	(89)	—
Domestic power plants	—	—	(44)
Enterprise/GulfTerra	—	183	507
Javelina	—	111	—
KIECO	—	108	—
Other	—	4	4
	$ 6	$ 91	$ 124

(1) Amounts represent an impairment of our investment in 2004, recording our proportionate share of losses from our investment in MCV in 2005 primarily based on MCV's impairment of the plant assets, and a gain on the sale in 2006.

Below is summarized financial information of our proportionate share of the operating results and financial position of our unconsolidated affiliates, including those in which we hold greater than a 50 percent interest.

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Operating results data:			
Operating revenues	$1,101	$1,476	$2,075
Operating expenses	741	1,407	1,428
Income (loss) from continuing operations	174	(163)	343
Net income (loss)[1]	174	(163)	343
Financial position data:[2]			
Current assets	$ 441	$ 942	
Non-current assets	2,408	3,423	
Short-term debt	82	242	
Other current liabilities	321	441	
Long-term debt	556	1,171	
Other non-current liabilities	592	632	
Minority interest	—	83	
Redeemable preferred stock	—	9	
Equity in net assets	1,298	1,787	

(1) Includes net income of $20 million, $15 million and $7 million in 2006, 2005 and 2004, related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

(2) Includes total assets of $417 million, and $485 million as of December 31, 2006 and 2005 related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

We received distributions and dividends of $177 million and $203 million in 2006 and 2005, which includes $38 million and less than $1 million of returns of capital, from our investments.

The following table shows revenues and charges resulting from transactions with our unconsolidated affiliates:

	2006	2005	2004
		(In millions)	
Operating revenue[1]	$64	$114	$194
Other revenue — management fees[2]	—	—	3
Cost of sales[2]	3	7	90
Reimbursement for operating expenses[2]	—	—	93
Other income	6	9	8
Interest income	46	47	44

(1) Decrease primarily due to the sale of investments in our Power segment.

(2) Decrease in activity during 2005 is due primarily to the sale of GulfTerra during 2004.

Accounts Receivable Sales Program. During the third quarter of 2006, we entered into agreements to sell certain accounts receivable to qualifying special purpose entities (QSPEs) under SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* As of December 31, 2006, we sold approximately $202 million of receivables, received cash of approximately $108 million, received subordinated beneficial interests of approximately $91 million, and recognized a loss of approximately $3 million. In conjunction with the sale, the QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $111 million on the closing date. We reflect the subordinated beneficial interest in receivables sold as accounts receivable from affiliates in our balance sheet. We reflect accounts receivable sold under this program and changes in the subordinated beneficial interests as operating cash flows in our statement of cash flows. Under the agreements, we earn a fee for servicing the accounts receivable and performing all administrative duties for the QSPEs which is reflected as a reduction of operation and maintenance expense in our income statement. The fair value of these servicing and administrative agreements as well as the fees earned were not material to our financial statements for the year ended December 31, 2006.

Matters that Could Impact Our Investments

International Power. As of December 31, 2006, we had equity investments in seven power generation and transmission facilities in Asia, Central America, and Brazil that are considered variable interests under FIN No. 46(R). We operate these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. Additionally, the long-term debt issued by these entities is recourse only to the project. We have investments in and advances to these entities as well as guarantees and other agreements which are as follows at December 31, 2006:

Porto Velho ($315 million). The state-owned facility that purchases power generated by the facility in Brazil has approached us with the opportunity to potentially sell them our interest in this power plant. Although we currently have no indications of an impairment of our investment, as we evaluate this potential opportunity, we could be required to record a loss based on the potential value we may receive.

In December 2006, the Brazilian tax authorities assessed a $30 million fine against the Porto Velho power project for allegedly not filing the proper tax forms related to the consumption of fuel by the power facility under its power purchase agreement. We believe the tax authority's claims are without merit.

Manaus / Rio Negro ($97 million). We have an agreement to transfer our ownership of this facility in Brazil to the power purchaser in January 2008.

Asian and Central American power investments ($105 million). We are in the process of selling these assets. Any changes in the political and economic conditions could negatively impact the amount of net proceeds we expect to receive upon their sale, which may result in additional impairments.

Domestic Power. During 2006, we completed the sales of our remaining investments in domestic power facilities. We continue to supply gas to MCV under natural gas supply contracts and recorded a loss in the third quarter of approximately $133 million on these contracts as they were no longer with an affiliate. Prior to the sale, we had not recognized the cumulative mark-to-market losses on these contracts to the extent of our ownership interest due to their affiliated nature. To secure our remaining obligations under these contracts, we have also issued letters of credit to MCV for approximately $208 million as of December 31, 2006.

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of December 31, 2006, our total investment and guarantees related to this pipeline project were approximately $117 million, of which the Bolivian portion was $3 million. In 2006, the Bolivian government announced a decree significantly increasing its interest in and control over Bolivia's oil and gas assets. We continue to monitor and evaluate, together with our partners, the potential commercial impact that recent political events in Bolivia could have on the Bolivia to Brazil pipeline. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Investment in Argentina. We own an approximate 22 percent interest in the Argentina to Chile pipeline. As of December 31, 2006, our total investment in this pipeline project was approximately $23 million. In July 2006, the Ministry of Economy and Production in Argentina issued a decree that significantly increases the export taxes on natural gas. We continue to evaluate, together with our partners, the potential commercial impact that this decree could have on the Argentina to Chile pipeline. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Citrus. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus, in which we own a 50 percent equity interest, settled a lawsuit in January 2007 million against Spectra LNG Sales, formerly Duke Energy LNG Sales, Inc., for wrongful termination of a gas supply contract that had been entered into by the parties in 1988. Pursuant to the settlement, Spectra LNG Sales paid CTC $100 million.

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, adjusted to reflect our discontinued operations, is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(In millions, except per common share amounts)				
2006					
Operating revenues	$1,337	$1,089	$ 942	$ 913	$4,281
Operating income	683	363	218	163	1,427
Earnings from unconsolidated affiliates	29	37	55	24	145
Income (loss) from continuing operations	301	134	111	(15)	531
Discontinued operations, net of income taxes	55	16	24	(151)	(56)
Net income (loss)	356	150	135	(166)	475
Net income (loss) available to common stockholders	346	141	126	(175)	438
Basic earnings per common share					
Income (loss) from continuing operations	0.44	0.19	0.15	(0.03)	0.73
Net income (loss)	0.53	0.21	0.18	(0.25)	0.65
Diluted earnings per common share					
Income (loss) from continuing operations	0.42	0.19	0.15	(0.03)	0.72
Net income (loss)	0.49	0.21	0.18	(0.25)	0.64
2005					
Operating revenues	$ 882	$1,036	$ 627	$ 814	$3,359
Operating income (loss)	127	335	(190)	(333)	(61)
Earnings (losses) from unconsolidated affiliates	173	(35)	—	143	281
Income (loss) from continuing operations	42	29	(275)	(302)	(506)
Discontinued operations, net of income taxes	64	(267)	(37)	144	(96)
Net income (loss)	106	(238)	(312)	(162)	(606)
Net income (loss) available to common stockholders	106	(246)	(321)	(172)	(633)
Basic and diluted earnings per common share					
Income (loss) from continuing operations	0.07	0.03	(0.44)	(0.47)	(0.82)
Net income (loss)	0.17	(0.38)	(0.50)	(0.26)	(0.98)

Below are unusual or infrequently occurring items, if any, in each of the respective quarters of 2006 and 2005:

December 31, 2006. (i) $188 million charge associated with the release of capacity under our Alliance contract and (ii) approximately $188 million in deferred taxes related to ANR discontinued operations (Note 2).

September 30, 2006. (i) Mark-to-market losses of $133 million on our MCV supply agreement recorded in conjunction with the sale of our interest in the related power facility and (ii) a $105 million income tax benefit associated with the reduction of tax contingencies and reinstatement of certain tax credits as a result of IRS audit settlements and net tax amounts recognized on certain foreign investments (note 5).

June 30, 2006. Income tax benefit of $34 million associated with IRS audit settlements (Note 5).

December 31, 2005. (i) $350 million charge associated with our retiree medical benefits legal matters (Note 13) and (ii) net gain of approximately $400 million on the sale of our south Louisiana processing facilities in discontinued operations.

September 30, 2005. (i) Proportionate share of our MCV investment's losses of approximately $160 million and (ii) a $109 million gain on sale of Korean power facility.

June 30, 2005. (i) Impairment of our Macae power facility in discontinued operations of approximately $300 million, (ii) $160 million of impairments on our other international power facilities, and (iii) approximately $70 million of income recorded upon receipt of payment under a bankruptcy claim.

March 31, 2005. (i) Gain on sale of remaining investment in Enterprise for $183 million, (ii) net losses associated with our other international power facilities of approximately $75 million, (iii) a $59 million charge associated with finalizing our Western Energy settlement, and (iv) approximately $30 million in income tax benefits primarily a result of IRS audit settlements (see Note 5).

Supplemental Natural Gas and Oil Operations (Unaudited)

Our Exploration and Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and NGL, in the United States, Brazil and Egypt.

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

	United States	Brazil and Egypt[1]	Worldwide
2006			
Natural gas and oil properties:			
Costs subject to amortization	$15,582	$460	$16,042
Costs not subject to amortization	333	77	410
	15,915	537	16,452
Less accumulated depreciation, depletion and amortization	11,322	202	11,524
Net capitalized costs	$ 4,593	$335	$ 4,928
2005			
Natural gas and oil properties:			
Costs subject to amortization	$14,764	$371	$15,135
Costs not subject to amortization	384	107	491
	15,148	478	15,626
Less accumulated depreciation, depletion and amortization	10,955	183	11,138
Net capitalized costs	$ 4,193	$295	$ 4,488

(1) Capitalized costs for Egypt were $4 million as of December 31, 2006.

Total Costs Incurred. Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows for the year ended December 31 (in millions):

	United States	Brazil and Egypt	Worldwide
2006			
Property acquisition costs			
Proved properties	$ 2	$ 2	$ 4
Unproved properties	34	1	35
Exploration costs	323	53	376
Development costs	738	40	778
Costs expended	1,097	96	1,193
Asset retirement obligation costs	3	—	3
Total costs incurred	$1,100	$ 96	$1,196
2005			
Property acquisition costs			
Proved properties	$ 643	$ 8	$ 651
Unproved properties	143	1	144
Exploration costs	143	15	158
Development costs	503	6	509
Costs expended	1,432	30	1,462
Asset retirement obligation costs	1	—	1
Total costs incurred	$1,433	$ 30	$1,463
Unconsolidated investment in Four Star(1)	$ 769	$ —	$ 769
2004			
Property acquisition costs			
Proved properties	$ 33	$ 69	$ 102
Unproved properties	32	3	35
Exploration costs	185	25	210
Development costs	395	1	396
Costs expended	645	98	743
Asset retirement obligation costs	30	3	33
Total costs incurred	$ 675	$101	$ 776

(1) Amount includes $179 million of deferred income tax adjustments related to the acquisition of full-cost pool properties and $217 million related to the acquisition of our unconsolidated investment in Four Star.

Pursuant to the full cost method of accounting, we capitalize certain general and administrative expenses related to property acquisition, exploration and development activities and interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. The table above includes capitalized internal general and administrative costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of $50 million, $47 million and $44 million for the years ended December 31, 2006, 2005, and 2004. We also capitalized interest of $30 million, $30 million and $22 million for the years ended December 31, 2006, 2005 and 2004.

In our January 1, 2007 reserve report, the amounts estimated to be spent in 2007, 2008 and 2009 to develop our consolidated worldwide proved undeveloped reserves are $424 million, $473 million and $243 million.

Unevaluated Capitalized Costs. We exclude capitalized costs of natural gas and oil properties from amortization that are in various stages of evaluation. We expect a majority of these costs to be included in the amortization calculation in 2007 and 2008.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditures that are not being amortized as of December 31, 2006, pending determination of proved reserves (in millions):

	Cumulative Balance[1] December 31, 2006	Costs Excluded for Years Ended[1] December 31 2006	2005	2004	Cumulative Balance December 31, 2003
United States					
Acquisition	$280	$ 39	$182	$24	$35
Exploration	52	36	3	1	12
Development	1	—	—	—	1
Total United States	333	75	185	25	48
Brazil & Egypt					
Acquisition	5	1	—	1	3
Exploration	72	51	10	10	1
Development	—	—	—	—	—
Total Brazil & Egypt	77	52	10	11	4
Worldwide	$410	$127	$195	$36	$52

(1) Includes capitalized interest of $24 million, $9 million and $1 million for the years ended December 31, 2006, 2005, and 2004.

Depreciation, Depletion, and Amortization Rates. Our total amortization expense per Mcfe for the United States was $2.43, $2.25 and $1.84 in 2006, 2005, and 2004 and $2.30, $2.33 and $2.02 for Brazil in 2006, 2005 and 2004. Included in our worldwide depreciation, depletion and amortization expense is accretion expense of $0.07/Mcfe, $0.10/Mcfe and $0.08/Mcfe for 2006, 2005 and 2004 for the United States and $0.03/Mcfe in 2006 and $0.01/Mcfe in 2005 and 2004 in Brazil attributable to SFAS No. 143.

Natural Gas and Oil Reserves. Net quantities of proved developed and undeveloped reserves of natural gas and NGL, oil, and condensate, and changes in these reserves at December 31, 2006 presented in the tables below are based on our internal reserve report. 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. Our consolidated reserves 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, an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, prepared an estimate on 84 percent of our consolidated natural gas and oil reserves. Additionally, Ryder Scott prepared an estimate of 80 percent of the proved 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.

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent
	United States	Brazil	Worldwide	United States	Brazil	Worldwide	United States	Volumes in Bcfe
Consolidated								
January 1, 2004	2,061	—	2,061	32,371	20,543	52,914	15,985	2,474
Revisions of previous estimates	(172)	—	(172)	(999)	252	(747)	724	(172)
Extensions, discoveries and other	79	38	117	2,214	1,848	4,062	58	142
Purchases of reserves in place	15	38	53	—	1,848	1,848	—	64
Sales of reserves in place	(21)	—	(21)	(1,276)	—	(1,276)	(47)	(29)
Production	(238)	(7)	(245)	(4,979)	(320)	(5,299)	(3,519)	(298)
December 31, 2004	1,724	69	1,793	27,331	24,171	51,502	13,201	2,181
Revisions of previous estimates	(43)	(2)	(45)	260	7,927	8,187	1,148	11
Extensions, discoveries and other	183	5	188	8,145	772	8,917	169	242
Purchases of reserves in place	192	—	192	13,338	—	13,338	772	276
Sales of reserves in place	(18)	—	(18)	(969)	—	(969)	(89)	(24)
Production	(207)	(16)	(223)	(4,877)	(620)	(5,497)	(2,639)	(271)
December 31, 2005	1,831	56	1,887	43,228	32,250	75,478	12,562	2,415
Revisions of previous estimates[(1)]	8	(1)	7	(1,514)	(365)	(1,879)	(1,834)	(15)
Extensions, discoveries and other	254	8	262	5,012	209	5,221	958	299
Purchases of reserves in place	1	—	1	90	—	90	32	2
Sales of reserves in place	(17)	—	(17)	(230)	—	(230)	(174)	(20)
Production	(213)	(7)	(220)	(5,907)	(247)	(6,154)	(1,532)	(266)
December 31, 2006	1,864	56	1,920	40,679	31,847	72,526	10,012	2,415
Proved developed reserves								
December 31, 2004	1,287	54	1,341	19,641	2,613	22,254	11,943	1,546
December 31, 2005	1,404	27	1,431	28,581	1,144	29,725	11,010	1,675
December 31, 2006	1,469	23	1,492	29,616	824	30,440	8,665	1,727
Unconsolidated investment in Four Star								
December 31, 2006								
Net proved developed and undeveloped reserves	167	—	167	2,947	—	2,947	6,209	222
Proved developed reserves	139	—	139	2,874	—	2,874	5,095	187
December 31, 2005								
Net proved developed and undeveloped reserves	193	—	193	3,349	—	3,349	6,668	253
Proved developed reserves	158	—	158	3,266	—	3,266	5,399	210

(1) Includes downward reserve revisions of approximately 54 Bcfe related to price and positive reserve revisions of 39 Bcfe related to performance.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of “reasonable certainty” be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2006.

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

	United States	Brazil and Egypt	Worldwide
2006			
Net Revenues			
Sales to external customers	$ 608	$ 41	$ 649
Affiliated sales	1,160	(9)	1,151
Total	1,768	32	1,800
Cost of products and services(1)	(58)	—	(58)
Production costs(2)	(318)	(7)	(325)
Depreciation, depletion and amortization	(611)	(19)	(630)
	781	6	787
Income tax expense	(281)	(2)	(283)
Results of operations from producing activities	$ 500	$ 4	$ 504
Equity earnings from unconsolidated investment in Four Star(3)	$ 10	$ —	$ 10
2005			
Net Revenues			
Sales to external customers	$ 466	$ 62	$ 528
Affiliated sales	1,268	(9)	1,259
Total	1,734	53	1,787
Cost of products and services(1)	(47)	—	(47)
Production costs(2)	(253)	(8)	(261)
Depreciation, depletion and amortization	(567)	(45)	(612)
	867	—	867
Income tax expense	(309)	—	(309)
Results of operations from producing activities	$ 558	$ —	$ 558
Equity earnings from unconsolidated investment in Four Star(3)	$ 19	$ —	$ 19
2004			
Net Revenues			
Sales to external customers	$ 534	$ 26	$ 560
Affiliated sales	1,175	—	1,175
Total	1,709	26	1,735
Cost of products and services(1)	(54)	—	(54)
Production costs(2)	(210)	—	(210)
Depreciation, depletion and amortization	(530)	(18)	(548)
	915	8	923
Income tax expense	(333)	(3)	(336)
Results of operations from producing activities	$ 582	$ 5	$ 587

(1) Cost of products and services consists primarily of transportation costs.
(2) Production cost includes lease operating costs and production related taxes, including ad valorem and severance taxes.
(3) Acquired in August 2005.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to our consolidated proved natural gas and oil reserves at December 31 is as follows (in millions):

	United States	Brazil	Worldwide
2006			
Future cash inflows[1]	$12,349	$1,977	$14,326
Future production costs	(3,623)	(431)	(4,054)
Future development costs	(1,280)	(506)	(1,786)
Future income tax expenses	(1,089)	(239)	(1,328)
Future net cash flows	6,357	801	7,158
10% annual discount for estimated timing of cash flows	(2,302)	(377)	(2,679)
Standardized measure of discounted future net cash flows	$ 4,055	$ 424	$ 4,479
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 4,225	$ 424	$ 4,649
2005			
Future cash inflows[1]	$18,175	$1,992	$20,167
Future production costs	(3,968)	(453)	(4,421)
Future development costs	(1,335)	(309)	(1,644)
Future income tax expenses	(3,160)	(286)	(3,446)
Future net cash flows	9,712	944	10,656
10% annual discount for estimated timing of cash flows	(3,660)	(381)	(4,041)
Standardized measure of discounted future net cash flows	$ 6,052	$ 563	$ 6,615
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 5,748	$ 560	$ 6,308
2004			
Future cash inflows[1]	$11,895	$1,077	$12,972
Future production costs	(3,585)	(135)	(3,720)
Future development costs	(1,234)	(274)	(1,508)
Future income tax expenses	(1,184)	(141)	(1,325)
Future net cash flows	5,892	527	6,419
10% annual discount for estimated timing of cash flows	(2,004)	(219)	(2,223)
Standardized measure of discounted future net cash flows	$ 3,888	$ 308	$ 4,196
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 3,907	$ 305	$ 4,212
Unconsolidated Investment in Four Star[2]			
Standardized measure of discounted future net cash flows			
2006	$ 323	$ —	$ 323
2005	$ 617	—	$ 617

(1) United States excludes $219 million, ($502) million and ($1) million of future net cash inflows (outflows) attributable to hedging activities in the years 2006, 2005 and 2004. Brazil excludes $4 million and $5 million of future net cash outflows attributable to hedging activities in 2005 and 2004.

(2) Four Star was acquired in August 2005.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end prices of $5.64, $10.08, and $6.22 per MMBtu for natural gas and $61.05, $61.04 and $43.35 per barrel of oil at December 31, 2006, 2005 and 2004. In the United States, after adjustments for transportation and other charges, net prices were $5.33 per Mcf of gas, $51.08 per barrel of oil and $34.36 per barrel of NGL at December 31, 2006. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in our consolidated worldwide standardized measure of discounted future net cash flows (in millions):

	Years Ended December 31,[1]		
	2006	2005	2004
		(In millions)	
Sales and transfers of natural gas and oil produced net of production costs	$(1,516)	$(1,477)	$(1,470)
Net changes in prices and production costs	(2,891)	2,884	29
Extensions, discoveries and improved recovery, less related costs	549	793	268
Changes in estimated future development costs	(55)	2	4
Previously estimated development costs incurred during the period	192	247	156
Revision of previous quantity estimates	(38)	47	(453)
Accretion of discount	827	476	568
Net change in income taxes	1,123	(1,093)	257
Purchases of reserves in place	4	956	114
Sale of reserves in place	(42)	(83)	(75)
Change in production rates, timing and other	(289)	(333)	(94)
Net change	$(2,136)	$ 2,419	$ (696)

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2006, 2005 and 2004
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2006[1]					
Allowance for doubtful accounts	$ 65	$ (5)	$ (27)[2]	$ (5)	$ 28
Valuation allowance on deferred tax assets	107	62	(39)	(3)	127
Legal reserves	574	48	(74)	—	548
Environmental reserves	348	30	(64)	—	314
Regulatory reserves	1	65	(1)	—	65
2005[1]					
Allowance for doubtful accounts	$ 195	$ (68)	$ (54)[2]	$ (8)	$ 65
Valuation allowance on deferred tax assets	51	40[3]	(5)	21	107
Legal reserves	592	496	(516)[4]	2	574
Environmental reserves	349	60	(61)[4]	—	348
Regulatory reserves	1	—	—	—	1
2004[1]					
Allowance for doubtful accounts	$ 269	$ (48)	$ (22)[2]	$ (4)	$195
Valuation allowance on deferred tax assets	9	46[3]	(4)	—	51
Legal reserves	1,169	145	(655)[4]	(67)	592
Environmental reserves	377	16	(46)[4]	2	349
Regulatory reserves	13	—	(12)	—	1

(1) Amounts reflect the reclassification of discontinued operations.

(2) In 2006, relates primarily to the sale of our accounts receivable under an accounts receivable sales program. In 2005 and 2004, relates primarily to accounts written off.

(3) Relates primarily to valuation allowances for deferred tax assets related to the Western Energy Settlement, foreign ceiling test charges, foreign asset impairments and state and foreign net operating loss carryovers.

(4) Relates primarily to payments for various litigation reserves (including $442 million and $602 million related to the Western Energy Settlement), environmental remediation reserves or revenue crediting and rate settlement reserves.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

As previously reported in our Current Report on Form 8-K dated April 18, 2006 (as amended on May 9, 2006), our audit committee appointed Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2006 and dismissed PricewaterhouseCoopers LLP. During the fiscal years ended December 31, 2006 and 2005, there were no "disagreements with our former accountant" or "reportable events" as defined in Item 304(a)(1)(iv) and Item 304(a)(1)(v) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2006, we carried out an evaluation under the supervision and with the participation of our management, including our CEO and our CFO, as to the effectiveness, design and operation of our disclosure controls and procedures, as defined by the Securities Exchange Act of 1934, as amended. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission (SEC) reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based on the results of this evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective at December 31, 2006. See Part II, Item 8, Financial Statements and Supplementary Data under Management's Annual Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the fourth quarter 2006.

ITEM 9B. OTHER INFORMATION

On February 22, 2007, we closed the previously announced sale of ANR Pipeline Company, our Michigan storage assets, and our 50 percent interest in Great Lakes Gas Transmission to TransCanada Corporation and TC Pipelines, LP. The sales price was approximately $4.1 billion, which included an assumption of $475 million of debt by the buyer. We have presented these operations as discontinued operations in this Form 10-K which satisfies our requirement to provide pro forma financial information related to this sale under Item 9.01 (b) (1) of Form 8-K.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information included under the captions "Corporate Governance", "Proposal No. 1 — Election of Directors", "Section 16(a), Beneficial Ownership Reporting Compliance" and "Information about the Board of Directors and Committees" in our Proxy Statement for the 2007 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Part I, Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

As required by the New York Stock Exchange corporate governance listing standards, in June 2006, Douglas L. Foshee, our president and chief executive officer, submitted an unqualified certification to the New York Stock Exchange that as of the date of the certification, he was not aware of any violation by El Paso of the exchange's corporate governance standards. The certifications of our chief executive officer and chief financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are attached as Exhibits 31.A and 31.B to this report

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the captions "Information about the Board of Directors and Committees — Compensation Committee Interlocks and Insider Participation", "Executive Compensation", "Director Compensation" and "Compensation Committee Report" in our Proxy Statement for the 2007 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information appearing under the captions "Security Ownership of Certain Beneficial Owners and Management" and "Equity Compensation Plan Information Table" in our Proxy Statement for the 2007 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information appearing under the captions "Corporate Governance — Independence of Board Members" and "Corporate Governance — Transactions with Related Persons" in our Proxy Statement for the 2007 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information appearing under the caption "Proposal No. 2 — Ratification of Appointment of Ernst & Young, LLP as our Independent Registered Public Accountant — Principal Accountant Fees and Services" and "Information about the Board of Directors — Policy for Approval of Audit and Non-Audit Fees," in our Proxy Statement for the 2007 Annual Meeting of Stockholders is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial statements.

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

The Exhibit Index, which index follows the signature page to this report and is hereby incorporated herein by reference, sets forth a list of those exhibits filed herewith, and includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 (b)(10)(iii) of Regulation S-K.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4) (iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 28th day of February, 2007.

EL PASO CORPORATION

By /s/ DOUGLAS L. FOSHEE

Douglas L. Foshee
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of El Paso Corporation and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ DOUGLAS L. FOSHEE Douglas L. Foshee	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2007
/s/ D. MARK LELAND D. Mark Leland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
/s/ JOHN R. SULT John R. Sult	Senior Vice President and Controller (Principal Accounting Officer)	February 28, 2007
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Chairman of the Board	February 28, 2007
/s/ JUAN CARLOS BRANIFF Juan Carlos Braniff	Director	February 28, 2007
/s/ JAMES L. DUNLAP James L. Dunlap	Director	February 28, 2007
/s/ ROBERT W. GOLDMAN Robert W. Goldman	Director	February 28, 2007
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 28, 2007
/s/ THOMAS R. HIX Thomas R. Hix	Director	February 28, 2007
/s/ WILLIAM H. JOYCE William H. Joyce	Director	February 28, 2007
/s/ FERRELL P. MCCLEAN Ferrell P. McClean	Director	February 28, 2007

Signature	Title	Date
/s/ STEVEN J. SHAPIRO Steven J. Shapiro	Director	February 28, 2007
/s/ J. MICHAEL TALBERT J. Michael Talbert	Director	February 28, 2007
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 28, 2007
/s/ JOHN L. WHITMIRE John L. Whitmire	Director	February 28, 2007
/s/ JOE B. WYATT Joe B. Wyatt	Director	February 28, 2007