EL PASO CORP/DE
Form 10-K
March 02, 2009

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

OR

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

For the transition period from to .

Commission File Number 1-14365

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

Delaware	**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 o No þ.

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

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

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

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

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

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

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

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of June 30, 2008, the last business day of the registrant s most recently completed second fiscal quarter, computed by reference to the closing sale price of the registrant s common stock on the New York Stock Exchange on such date: $15,274,845,165.

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 23, 2009: 698,613,542

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 2009 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2009.

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

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

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

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

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PART I

ITEM 1. BUSINESS

Business and Strategy

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

Natural Gas Transmission. We own or have interests in North America s largest interstate pipeline system with approximately 42,000 miles of pipe that connect North America s major natural gas producing basins to its major consuming markets. We also provide approximately 230 Bcf of storage capacity and have an LNG receiving terminal and related facilities in Elba Island, Georgia with 933 MMcf of daily base load sendout capacity. The size, connectivity and diversity of our U.S. pipeline system provides growth opportunities through infrastructure development or large scale expansion projects and gives us the capability to adapt to the dynamics of shifting supply and demand. Our focus is to enhance the value of our transmission business by successfully executing on our backlog of committed expansion projects in the United States and Mexico and developing growth projects in our market and supply areas.

Exploration and Production. Our exploration and production business 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, 2008, we held an estimated 2.3 Tcfe of proved natural gas and oil reserves, not including our equity share in the proved reserves of an unconsolidated affiliate of 0.2 Tcfe. In this business, we are focused on growing our reserve base over the long-term through disciplined capital allocation and portfolio management, cost control and marketing our natural gas and oil production at optimal prices while managing associated price risks.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Our business segments provide a variety of energy products and services and are managed separately as each segment requires different technology and marketing strategies. For a further discussion of our business segments, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

Pipelines Segment

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

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

- providing outstanding customer service;
- executing successfully on our backlog of committed expansion projects;
- developing new growth projects in our market and supply areas;
- ensuring the safety of our pipeline systems and assets;
- optimizing our contract portfolio; and
- focusing on efficiency and synergies across our systems.

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Natural gas pipeline systems. The tables below provide more information on our pipeline systems:

		As of December 31, 2008						
Transmission System	**Supply and Market Region**	**Ownership Percentage (Percent)**	**Miles of Pipeline**	**Design Capacity (MMcf/d)**	**Storage Capacity (Bcf)**	**Average Throughput[1] 2008**	**2007 (BBtu/d)**	**2006**
Tennessee Gas Pipeline (TGP)	Extends from Louisiana, the Gulf of Mexico and south Texas to the northeast section of the U.S., including the metropolitan areas of New York City and Boston.	100	13,600	7,069	92[2]	4,864	4,880	4,534
El Paso Natural Gas (EPNG)	Extends from San Juan, Permian, Anadarko basins and via interconnects the Rocky Mountains to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650[3]	44	4,379	4,189	4,179
Mojave Pipeline (MPC)	Connects with the EPNG system near Cadiz, California, the EPNG and Transwestern systems at Topock, Arizona and to the Kern River Gas Transmission Company system in California. This system also extends to customers in the vicinity of Bakersfield, California.	100	400	400[4]		349	458	461
Cheyenne Plains Gas	Extends from Cheyenne hub and	100	400	934		898	735	583

Pipeline (CPG)	Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.

(1) Includes throughput transported on behalf of affiliates.

(2) Includes 29 Bcf of storage capacity from Bear Creek Storage Company (Bear Creek) which TGP owns equally with Southern Natural Gas Company.

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

(4) Reflects east to west flow capacity.

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		As of December 31, 2008						
Transmission System	Supply and Market Region	Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[(1)] 2008	2007 (BBtu/d)	2006
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.	94	7,600	3,700	60[(2)]	2,339	2,345	2,167
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.	90	4,100	3,920	29	2,225	2,339	2,008
Wyoming Interstate (WIC)	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne,	74	800	3,105		2,543	2,071	1,914

	Wyoming.							
Florida Gas Transmission (FGT)(3)	Extends from South Texas to South Florida.	50	5,000	2,100		2,147	2,056	2,018
Samalayuca Pipeline and Gloria a Dios Compression Station(4)	Extends from U.S.-Mexico border into the state of Chihuahua, Mexico.	50	23	460		428	462	442
San Fernando Pipeline(4)	Extends from Pemex Compression Station 19 to the Pemex metering station in San Fernando, Mexico in the State of Tamaulipas.	50	71	1,000		951	951	951

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

(2) Includes 29 Bcf of storage capacity from Bear Creek which SNG owns equally with TGP.

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

(4)

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

Liquefied Petroleum Gas Pipeline System. In December 2007, we placed the LPG Burgos pipeline in service. This 117 mile pipeline, in which we own 50 percent, transports liquefied petroleum gas and extends from Pemex s Burgos complex to the Monterrey market in the state of Nuevo León, Mexico. The system has a design capacity of 34 million barrels/day and we transported an average of 30 million barrels/day in 2008 and 2007.

WYCO Development Company (WYCO). We own a 50 percent interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). In November 2008, the High Plains pipeline was placed in service. The High Plains pipeline is owned by WYCO and operated by us and consists of a 164-mile interstate gas pipeline extending from the Cheyenne Hub in northeast Colorado to PSCo s Fort St. Vrain electric generation plant and other points of interconnections with PSCo s system. WYCO also owns a state regulated interstate gas pipeline that extends from the Cheyenne Hub in northeast Colorado to PSCo s Fort St. Vrain s electric generation plant, which we do not operate.

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Underground Natural Gas Storage Facilities. In addition to the storage capacity in our wholly and majority owned pipeline systems, we have interests in the following natural gas storage facilities:

Storage Entity	As of December 31, 2008 Ownership Interest (Percent)	Storage Capacity (Bcf)	Location
Bear Creek	100	58(1)	Louisiana
Young Gas Storage	48	6	Colorado

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

Master Limited Partnership. At December 31, 2008, our master limited partnership, El Paso Pipeline Partners, L.P. (EPB) (formed in 2007), owns the Wyoming Interstate system, a 40 percent general partner interest in CIG and a 25 percent general partner interest in SNG. We have a two percent general partner interest and a 72 percent limited partner interest in EPB.

FERC Approved Pipeline and Storage Expansion Projects. As of December 31, 2008, we had the following significant FERC-approved expansion projects on our systems. For a further discussion of other expansion projects, see Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Pipeline Projects

Project	Existing System	Capacity (MMcf/d)	Description	Anticipated Completion or In-Service Date
Carthage Expansion	TGP	98	To install a new 7,700 horsepower compressor station in DeSoto Parish, Louisiana, abandon three 1,100 horsepower units and install a 10,310 horsepower gas turbine unit to upgrade and replace compression at our existing Compressor Station 47 located in Ouachita Parish, Louisiana.	May 2009
Piceance Lateral Expansion	WIC	219	To construct an additional 17,678 horsepower to increase capacity to transport supply from the Piceance Basin	October 2009
Concord Lateral Expansion	TGP	29	To construct a new 6,130 horsepower compressor station on our Line 200 system in Pelham, New Hampshire.	November 2009
Cypress Phase III(1)	SNG	161	To add 20,700 horsepower of additional compression on pipeline facilities extending southward from our Elba Island facility	First half of 2011

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Storage Projects

Storage Project	Storage Capacity (Bcf)	Description	Anticipated Completion or In-Service Date
Black Warrior Storage	25	To construct a multi-cycle natural gas storage facility in Monroe and Lowndes Counties, Mississippi. The facilities will include three 8,000 horsepower electric driven reciprocating compressor units, gas processing and dehydration units and a 4.6 mile, 24 inch pipeline that will interconnect with our system.	(2)
Totem Gas Storage(3)	7(4)	To develop a natural gas storage field that services and interconnects with the High Plains Pipeline having 10.7 Bcf of natural gas storage capacity, 7 Bcf of which will be working gas capacity, with a 200 MMcf/d maximum withdrawal rate and 100 MMcf/d maximum injection rate.	July 2009

(1) Construction of Cypress Phase III is at the option of BG LNG Services.

(2) This project is not fully contracted and is not included in our inventory of committed pipeline expansion projects at this time.

(3) This joint project between us and an affiliate of PSCo will be operated by us and owned by WYCO.

(4) All of the working storage

capacity is fully contracted with PSCo to cover the cost of service (including a return on our investment) pursuant to a firm contract through 2040.

LNG Facilities

Elba Island LNG. We own an LNG receiving terminal located on Elba Island, near Savannah, Georgia with a peak sendout capacity of 1.2 Bcf/d and a base load sendout capacity of 0.9 Bcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas Group and Royal Dutch Shell PLC.

In September 2007, we received FERC approval to expand the Elba Island LNG receiving terminal and construct the Elba Express Pipeline. The expansion is anticipated to increase the peak sendout capacity of the terminal from 1.2 Bcf/d to 2.1 Bcf/d. The Elba Express Pipeline will consist of approximately 190 miles of pipeline with a total capacity of 1.2 Bcf/d, which will transport natural gas from the Elba Island LNG terminal to markets in the southeastern and eastern United States.

Gulf LNG. In February 2008, we completed our acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, which is constructing a FERC-approved LNG terminal in Pascagoula, Mississippi with a designed sendout capacity of 1.5 bcf/d that is expected to be placed in service in October 2011.

Markets and Competition

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

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

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

We expect growth of the natural gas market will be adversely affected by the current economic recession in the U.S. and global economies. The decline in economic activity will reduce industrial demand for natural gas and electricity, which will cause lower natural gas demand both directly in end-use markets and indirectly through lower power generation demand for natural gas. The demand for natural gas and electricity in the residential and commercial segments of the market will likely be less affected by the economy. The lower demand and the credit restrictions on investments in the current environment may also slow development of supply projects. As a result, our pipelines may experience lower throughput, lower revenues and slower development of new expansion projects. While our pipeline systems could experience some level of reduced throughput and revenues, or slower development of expansion projects as a result of these factors, each generates a significant portion of their revenues through monthly reservation or demand charges on long-term contracts at rates stipulated under our tariffs.

Our existing transportation and storage contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the maximum allowable rates allowed under our tariffs although, at times, we enter into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems. The weighted average remaining contract term for active contracts is approximately six years. The table below shows our firm transportation contracts as of December 31, 2008 for our wholly and majority owned systems.

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The following table details information related to our pipeline systems, including the customers, contracts, markets served and the competition faced by each as of December 31, 2008. Firm customers reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities and are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Interruptible customers are customers without reserved capacity that pay usage charges based on the volume of gas they request to transport, store, inject or withdraw.

Customer Information	Contract Information	Competition
TGP		
Approximately 470 firm and interruptible customers.	Approximately 510 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in its northeast, Appalachian, midwest and southeast market areas. It competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on the TGP system competes with alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. In addition, TGP competes with pipelines and gathering systems for connection to new supply sources in Texas, the Gulf of Mexico and from the Canadian border.
Major Customer: National Grid USA and subsidiaries (736 BBtu/d)	Expire in 2010-2027.	
EPNG		
Approximately 160 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately three years.	EPNG faces competition in the west and southwest from other existing and proposed pipelines, from California storage facilities, and from alternative energy sources that are used to generate electricity such as hydroelectric power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into the southwestern U.S. and northern Mexico were completed in 2008.
Major Customers: Sempra Energy and Subsidiaries including Southern California Gas Company (SoCal) (130 BBtu/d) (246 BBtu/d) (323 BBtu/d)	Expires in 2009. Expires in 2010. Expires in 2011.	

ConocoPhillips Company	
(447 BBtu/d)	Expires 2009.
(150 BBtu/d)	Expires 2010.
(392 BBtu/d)	Expires 2012.
Southwest Gas Corporation	
(412 BBtu/d)	Expires in 2011.
(75 BBtu/d)	Expires in 2015.

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Customer Information	Contract Information	Competition
MPC		
Approximately 10 firm and interruptible customers	Approximately five 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 power, nuclear energy, wind, solar, coal and fuel oil. In addition, construction of facilities to bring LNG into the southwestern U.S. and northern Mexico were completed in 2008.
Major Customer: EPNG (312 BBtu/d)	Expires in 2015.	
CPG		
Approximately 40 firm and interruptible customers	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately eleven years.	CPG competes directly with other interstate pipelines serving the mid-continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets.
Major Customers: Oneok Energy Services Company L.P. (195 BBtu/d)	Expires in 2015.	
Encana Marketing (USA) Inc. (170 BBtu/d)	Expires in 2015.	
Anadarko Petroleum Corporation (195 BBtu/d)	Expire in 2015-2016.	
Shell Energy North America US, L.P. (125BBtu/d)	Expires in 2019.	

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Customer Information	Contract Information	Competition
SNG		
Approximately 270 firm and interruptible customers	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately five years.	SNG faces competition in a number of its key markets. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on SNG s system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. SNG s four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, SNG competes with several pipelines for the transportation business of their other customers. In addition, SNG competes with pipelines and gathering systems for connection to new supply sources.
Major Customers:		
Atlanta Gas Light Company[1]		
(30 BBtu/d)	Expires in 2009.	
(152 BBtu/d)	Expires in 2010.	
(282 BBtu/d)	Expires in 2011.	
(545 BBtu/d)	Expire in 2012-2015.	
Southern Company Services		
(28 BBtu/d)	Expires in 2010.	
(390 BBtu/d)	Expire in 2017-2018.	
Alabama Gas Corporation		
(39 BBtu/d)	Expires in 2010.	
(323 BBtu/d)	Expires in 2011.	
(31 BBtu/d)	Expires in 2013.	
SCANA Corporation		
(8 BBtu/d)	Expires in 2009.	
(161 BBtu/d)	Expires in 2010.	
(146 BBtu/d)	Expire in 2017-2019.	

(1) Atlanta Gas Light Company is currently releasing a significant portion of its firm capacity to

a subsidiary of SCANA Corporation under terms allowed by our tariff.

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Customer Information	Contract Information	Competition
CIG		
Approximately 120 firm and interruptible customers	Approximately 170 firm transportation contracts. Weighted average remaining contract term of approximately eight years.	CIG serves two major markets, an on-system market and an off-system market. Its on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an intrastate pipeline, an interstate pipeline, local production from the Denver-Julesburg basin, and long-haul shippers who elect to sell into this market rather than the off-system market. CIG s off-system market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the midwest, the southwest, California and the Pacific northwest. Competition for this off-system market consists of interstate pipelines that are directly connected to its supply sources. CIG faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.
Major Customers:		
PSCo		
(5 BBtu/d)	Expires in 2009.	
(1,764 BBtu/d)	Expire in 2012-2029.	
Williams Gas Marketing, Inc.		
(37 BBtu/d)	Expires in 2009.	
(113 BBtu/d)	Expires in 2010.	
(175 BBtu/d)	Expires in 2011.	
(175 BBtu/d)	Expires in 2013.	
Anadarko Petroleum Corporation		
(11 BBtu/d)	Expires in 2009.	
(80 BBtu/d)	Expires in 2010.	

(24 BBtu/d)	Expires in 2011.	
(164 BBtu/d)	Expire in 2012-2015.	
WIC		
Approximately 50 firm and interruptible customers	Approximately 70 firm transportation contracts. Weighted average remaining contract term of approximately eight years.	WIC competes with existing pipelines to provide transportation services from supply basins in northwest Colorado, eastern Utah and Wyoming to pipeline interconnects in northeast Colorado, and western Wyoming. WIC faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.
Major Customers:		
Williams Gas Marketing, Inc.		
(84 BBtu/d)	Expires in 2010.	
(822 BBtu/d)	Expire in 2013-2021.	
Anadarko Petroleum Corporation		
(8 BBtu/d)	Expires in 2009.	
(28 BBtu/d)	Expires in 2010.	
(100 BBtu/d)	Expires in 2011.	
(1014 BBtu/d)	Expire in 2013-2023.	

Regulatory Environment. Our interstate natural gas transmission systems and storage operations are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves 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. The FERC s authority also extends to:

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

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Exploration and Production Segment

Our Exploration and Production segment s business strategy focuses on the exploration for and the acquisition, development and production of natural gas, oil and NGL in the United States, Brazil and Egypt. As of December 31, 2008, we controlled 3.8 million net leasehold acres and our proved natural gas and oil reserves at December 31, 2008, were approximately 2.3 Tcfe, which do not include 0.2 Tcfe related to our unconsolidated investment in Four Star Oil and Gas Company (Four Star). During 2008, daily equivalent natural gas production averaged approximately 742 MMcfe/d, not including 74 MMcfe/d from our equity investment in Four Star. We have a balanced portfolio of development and exploration projects that include both long-lived and shorter-lived properties that we operate through four regions in the U.S. and an international division.

Over the past five years, we have grown our exploration and production business through a combination of acquisitions and organic growth initiatives. Our acquisitions include Medicine Bow, which had operations in the western U.S. along with an ownership interest in Four Star; Peoples Energy Production Company (Peoples), with operations in east and south Texas, north Louisiana and Mississippi; and producing properties and undeveloped acreage in Zapata County, Texas. Supplementing these acquisitions were smaller bolt-on acquisitions of incremental interests where we already had existing operations. Our organic growth has mainly focused on expanding acreage and inventory in proximity to our existing core assets. During 2008, as part of our efforts to high grade our asset portfolio, we completed the sale of non-core properties primarily in the Texas Gulf Coast and Gulf of Mexico regions. In January 2009, we also completed the sale of two additional non-core natural gas producing properties in the Western and Central regions. The combination of these transactions have increased the onshore U.S. weighting of our existing inventory.

United States

Central. The Central region includes operations that are primarily focused on tight gas sands, coal bed methane, shale gas and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this region. During 2008, we invested $494 million on capital projects, including producing property acquisitions of $17 million, and production averaged 238 MMcfe/d. The principal operating areas are listed below:

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Area	Description	Net Acres	2008 Capital Investment (In millions)	Average Production (MMcfe/d)
East Texas/North Louisiana (Arklatex)	Concentrated land positions primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. Our operations are primarily in the Bear Creek, Holly, Minden, Bald Prairie, Bethany Longstreet and Logansport fields. We have new production and development activities in several fields in the Haynesville Shale. We also have production and additional land positions in Mississippi. In January 2009, we sold certain natural gas producing properties in the Arklatex area.	149,000	$385	152
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, we have a 50 percent average working interest covering approximately 46,000 net acres operated by Black Warrior Methane which produces from the Brookwood Field.	111,000	$50	59
Mid-Continent	Primarily in Oklahoma with a focus on development projects in the Arkoma Basin where we utilize horizontal drilling in the Hartshorne Coals for coal bed methane production. We have 219,000 net acres in the Illinois Basin, focused on the development of the New Albany Shale in southwestern Indiana. We are the operator of these properties and have a 95 percent working interest in this area which is producing and still under evaluation for further investment.	518,000	$59	27

Western. The Western region includes operations that are primarily focused on coal bed methane, shale gas and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this region. During 2008, we invested $240 million on capital projects, including producing property acquisitions of approximately $34 million, and production averaged 154 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2008 Capital Investment (In millions)	Average Production (MMcfe/d)
Rocky Mountains (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 own and operate the Altamont and Bluebell processing	401,000	$158	78

	plants and related gathering systems in Utah. We also have a non-operated working interest primarily in the Stadium Unit in the Williston Basin of North Dakota, which is undergoing secondary recovery.			
Raton Basin	Primarily focused on coal bed methane production in the Raton Basin of northern New Mexico and southern Colorado where we own the minerals beneath the Vermejo Park Ranch. We also have working interests in land positions in the San Juan Basin, primarily in the Fruitland Coal and Dakota formations and the tight gas formations in Pictured Cliffs and Mesaverde. In January 2009, we sold our natural gas producing properties in the San Juan Basin.	606,000	$82	76

Texas Gulf Coast. The Texas Gulf Coast region focuses on developing and exploring for tight gas sands in south Texas and the upper Gulf Coast of Texas. In this area, we have licensed over 10,000 square miles of three dimensional (3D) seismic data. During 2008, we invested $519 million on capital projects, and production averaged 225 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2008 Capital Investment (In millions)	Average Production (MMcfe/d)
Vicksburg/Frio Trends	Includes concentrated and contiguous assets, located in south Texas, including the Jeffress and Monte Christo fields primarily in Hidalgo county, in which we have an average 90 percent working interest. We also have assets in the Alvarado and Kelsey fields in Starr and Brooks counties with an average working interest of over 83 percent.	63,000	$195	128
Upper Gulf Coast Wilcox	Located onshore Texas Gulf Coast, including Renger, Dry Hollow, Brushy Creek and Speaks fields located in Lavaca county, and Graceland Field located in Colorado county.	45,000	$119	33
South Texas Wilcox	Includes working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. We also have working interests in the Laredo and Loma Novia fields in Webb and Duval counties.	62,000	$205	64

Gulf of Mexico and south Louisiana. Our Gulf of Mexico and south Louisiana operations are generally characterized by relatively high initial production rates, resulting in higher near-term cash flows, and high decline rates. During 2008, we invested $248 million on drilling, workover and facilities projects and production averaged 114 MMcfe/d. During 2008, as part of our efforts to high grade our asset portfolio, we divested a number of non-core oil and gas properties in this region. The principal operating areas are listed below:

Area	Description	Net Acres	2008 Capital Investment (In millions)	Average Production (MMcfe/d)
Gulf of Mexico	Primarily drilling interests in 82 Blocks south of the Louisiana, Texas and Alabama shorelines focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 300 feet).	275,000	$215	97
South Louisiana	Primarily in Vermilion Parish and associated bays and inland waters in southwestern Louisiana covered by the Catapult 3D seismic project. We have internally processed 2,800 square miles of contiguous 3D seismic data in this project.	13,000	$33	17

Unconsolidated Investment in Four Star. We have a 49 percent ownership interest in Four Star. Four Star operates onshore in the San Juan, Permian, Hugoton and South Alabama Basins and in the Gulf of Mexico. During 2008, our proportionate share of Four Star s daily equivalent natural gas production averaged approximately 74 MMcfe/d and at December 31, 2008, proved natural gas and oil reserves, net to our interest, were 0.2 Tcfe.

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International

Brazil. Our Brazilian operations cover approximately 329,000 net acres in seven blocks and eight development areas in the Camamu, Espirito Santo and Potiguar basins located offshore Brazil. During 2008, we invested $172 million on capital projects in Brazil, and production averaged 11 MMcfe/d. Our operations in each basin are described below:

Camamu Basin. In 2008, we retained a 100 percent working interest in two development areas in the BM-CAL-4 block, namely the Camarao and Pinauna Fields, and relinquished the remainder of the acreage in the block. In Pinauna, we are in the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development. In October 2008, IBAMA, the environmental regulatory agency in Brazil, issued the Terms of Reference for the project to us, which represents the first major step in the environmental permitting process. The timing of the Pinauna Field development will be dependent on the receipt of all required regulatory approvals and either the recovery of commodity prices or cost reductions that reflect the current low commodity price environment.

We also own an approximate 18 percent working interest in the BM-CAL-5 and BM-CAL-6 blocks in the Camamu Basin, operated by Petrobras. In 2008, we participated in drilling an exploratory well in the BM-CAL-6 block that was unsuccessful. We continue to evaluate other opportunities in this block. We also participated in drilling an exploratory well in the BM-CAL-5 block and found hydrocarbons. We are currently evaluating the results and appraisal options on BM-CAL-5 and plan to participate in drilling a second exploratory well in the block during 2009.

Espirito Santo Basin. During 2008 and early 2009, we executed a unitization agreement and gas and condensate sales agreements with Petrobras to develop the Camarupim Field which was discovered in 2007. A unitization agreement is required to develop this field because the field extends onto a block south of the ES-5 block in which we did not own a working interest. Under the unitization agreement, we will own an approximate 24 percent working interest in the Camarupim Field. The gas sales agreement provides for a price that adjusts quarterly based on a basket of fuel oil prices, while the condensate sales agreement provides for a price that adjusts monthly based on a Brent crude price less a fixed differential that will adjust annually. The plan of development for the field includes drilling four horizontal natural gas wells. As of December 31, 2008, one well has been drilled and tested and two additional wells have been spud. We expect to complete all drilling operations and begin production from the field in the second quarter of 2009.

Also, in 2008, we participated with Petrobras in drilling an exploratory well in the ES-5 block in which we own a 35 percent working interest. Hydrocarbons were found in the well and we are now evaluating the results. The exploratory well is located north of the Camarupim Field. Petrobras plans to drill another exploratory well on this block during 2009.

Potiguar Basin. We own a 35 percent working interest in the Pescada-Arabaiana Fields. Our production from these fields averaged approximately 11 MMcfe/d in 2008. We also own an interest in two blocks, BM-POT-11 and BM-POT-13, in the Potiguar Basin where we have no proved reserves or production. In the second quarter of 2009, we expect to enter into an agreement with Petrobras to relinquish our interest in these two blocks.

Egypt. As of December 31, 2008, our Egyptian operations cover approximately 1.2 million net acres in two blocks located primarily onshore in Egypt s Western Desert. During 2008, we invested $26 million on capital projects in Egypt. In 2008, we completed the acquisition of seismic data on our operated South Mariut block and continue to interpret the data. In January 2009, we completed a transaction with RWE Dea AG (RWE Dea) to swap a 40 percent working interest in our South Mariut block for an equal working interest in RWE Dea s Tanta block. The Tanta block contains approximately 820,000 acres and is located in the Nile Delta area just to the east of and adjacent to our South Mariut block. The swap with RWE Dea allows us to expand our acreage position and diversify our portfolio in Egypt. We spudded our first exploratory well in the South Mariut block in late January 2009 and plan to drill two to three additional exploratory wells in the South Mariut block in 2009. We also own a 22 percent non-operated working interest in approximately 8,000 net acres in the South Feiran concession located offshore in the Gulf of Suez. During 2008, we participated in drilling an exploratory well in the South Feiran block that was unsuccessful. We continue to evaluate other opportunities in this block.

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Natural Gas and Oil Properties

Natural Gas, Oil and Condensate and NGL Reserves and Production

The table below presents information about our estimated proved reserves as of December 31, 2008 based on an internal reserve report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2008.

	Net Proved Reserves					2008
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	(Percent)	Production (MMcfe)
Reserves and Production by Region						
United States						
Central	972,161	2,560	235	988,933	42%	87,008
Western	628,133	14,844	38	717,427	31%	56,429
Texas Gulf Coast	374,631	2,548	3,555	411,248	18%	82,439
Gulf of Mexico and south Louisiana	116,081	3,958	331	141,819	6%	41,869
Total United States	2,091,006	23,910	4,159	2,259,427	97%	267,745
Brazil	46,919	3,180		65,999	3%	3,928
Total	2,137,925	27,090	4,159	2,325,426	100%	271,673
Unconsolidated investment in Four Star	175,662	2,199	5,518	221,962	100%	26,899
Reserves by Classification						
United States						
Producing	1,306,383	13,834	2,725	1,405,741	62%	
Non-Producing	256,749	5,965	893	297,900	13%	
Undeveloped	527,874	4,111	541	555,786	25%	
Total proved	2,091,006	23,910	4,159	2,259,427	100%	
Brazil						
Producing	8,802	283		10,500	16%	
Non-Producing	3,394	332		5,387	8%	
Undeveloped	34,723	2,565		50,112	76%	
Total proved	46,919	3,180		65,999	100%	
Worldwide						
Producing	1,315,185	14,117	2,725	1,416,241	61%	
Non-Producing	260,143	6,297	893	303,287	13%	

Undeveloped	562,597	6,676	541	605,898	26%
Total proved	2,137,925	27,090	4,159	2,325,426	100%
Unconsolidated investment in Four Star					
Producing	145,794	2,151	4,488	185,624	84%
Non-Producing	2,996		28	3,165	1%
Undeveloped	26,872	48	1,002	33,173	15%
Total Four Star	175,662	2,199	5,518	221,962	100%

Our consolidated reserves in the table above are consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), an independent reservoir engineering firm that reports to the Audit Committee of our Board of Directors, conducted an audit of the estimates of 80 percent of our consolidated proved natural gas and oil reserves as of December 31, 2008. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising

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approximately 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 84 percent of the proved natural gas and oil reserves of Four Star, our unconsolidated affiliate. Our estimates of Four Star s proved natural gas and oil reserves are prepared by our internal reservoir engineers and do not reflect those prepared by the engineers of Four Star. Based on the amount of proved reserves determined by Ryder Scott, we believe our reported reserve amounts are reasonable. Ryder Scott s reports are included as exhibits to this Annual Report on Form 10-K.

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

All estimates of proved reserves are determined according to the rules currently prescribed by the Securities and Exchange Commission (SEC). These rules indicate that the standard of reasonable certainty be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive or upward revision is more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as reserves are produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2008, (ii) our interest in natural gas and oil wells at December 31, 2008 and (iii) our exploratory and development wells drilled during the years 2006 through 2008. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		**Undeveloped**		**Total**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Acreage						
United States						
Central	477,667	287,364	657,075	490,862	1,134,742	778,226
Western	383,201	294,054	912,896	713,236	1,296,097	1,007,290
Texas Gulf Coast	146,353	95,956	124,289	73,953	270,642	169,909
Gulf of Mexico and south Louisiana	147,849	115,248	209,726	172,968	357,575	288,216
Total United States	1,155,070	792,622	1,903,986	1,451,019	3,059,056	2,243,641
Brazil	72,281	37,640	1,103,321	290,862	1,175,602	328,502

Egypt			1,225,000	1,190,600	1,225,000	1,190,600
Worldwide Total	1,227,351	830,262	4,232,307	2,932,481	5,459,658	3,762,743

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

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

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In the United States, our net developed acreage is concentrated primarily in New Mexico (16 percent), Texas (15 percent), Utah (15 percent), Louisiana (11 percent), Oklahoma (9 percent) and Alabama (8 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (31 percent), Indiana (14 percent), the Gulf of Mexico (11 percent), Wyoming (9 percent), West Virginia (9 percent), Texas (7 percent) and Colorado (6 percent). Approximately 7 percent, 6 percent and 10 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2009, 2010 and 2011, respectively. Approximately 20 percent, 20 percent and 17 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2009, 2010 and 2011, respectively. Approximately 31 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2010. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or through farm-out agreements with other operators.

	Natural Gas		**Oil**		**Total**		**Wells Being Drilled at December 31, 2008**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)(3)**	**Gross(1)**	**Net(2)**
Productive Wells								
United States								
Central	3,591	2,601	17	9	3,608	2,610	32	18
Western	1,389	950	452	333	1,841	1,283	2	1
Texas Gulf Coast	1,498	1,037			1,498	1,037	10	6
Gulf of Mexico and south Louisiana	64	48	33	27	97	75	2	2
Total	6,542	4,636	502	369	7,044	5,005	46	27
Brazil	5	1	5	2	10	3	4	1
Worldwide Total	6,547	4,637	507	371	7,054	5,008	50	28

	Net Exploratory(2)			**Net Development(2)**		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Wells Drilled						
United States						
Productive	163	214	106	278	238	319
Dry	2	12	6	7	1	2
Total	165	226	112	285	239	321
Brazil						
Productive		3				
Dry						
Total		3				
Worldwide						
Productive	163	217	106	278	238	319

Dry	2	12	6	7	1	2
Total	165	229	112	285	239	321

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

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

(3) At December 31, 2008, we operated 4,534 of the 5,008 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.

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Net Production, Sales Prices, Transportation and Production Costs

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

	2008	2007	2006
Consolidated Volumes, Prices, and Costs per Unit:			
Net Production Volumes			
United States			
Natural gas (MMcf)	229,518	238,021	213,262
Oil, condensate and NGL (MBbls)	6,371	7,664	7,439
Total (MMcfe)	267,745	284,005	257,899
Brazil			
Natural gas (MMcf)	3,185	4,295	7,140
Oil, condensate and NGL (MBbls)	124	157	247
Total (MMcfe)	3,928	5,237	8,619
Worldwide			
Natural gas (MMcf)	232,703	242,316	220,402
Oil, condensate and NGL (MBbls)	6,495	7,821	7,686
Total (MMcfe)	271,673	289,242	266,518
Total (MMcfe/d)	742	792	730
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Excluding hedges	$ 8.51	$ 6.60	$ 6.77
Including hedges	$ 8.18	$ 7.36	$ 6.50
Brazil			
Excluding hedges	$ 2.60	$ 2.61	$ 2.61
Including hedges	$ 2.60	$ 2.61	$ 2.61
Worldwide			
Excluding hedges	$ 8.43	$ 6.53	$ 6.64
Including hedges	$ 8.10	$ 7.28	$ 6.38
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Excluding hedges	$ 82.96	$ 63.56	$ 55.95
Including hedges	$ 77.74	$ 63.56	$ 55.95
Brazil			
Excluding hedges	$ 96.21	$ 70.86	$ 64.02
Including hedges	$ 96.21	$ 41.27	$ 54.48
Worldwide			
Excluding hedges	$ 83.21	$ 63.71	$ 56.21
Including hedges	$ 78.10	$ 63.11	$ 55.90
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.32	$ 0.27	$ 0.24
Oil, condensate and NGL ($/Bbl)	$ 0.98	$ 0.83	$ 0.85
Worldwide			
Natural gas ($/Mcf)	$ 0.31	$ 0.27	$ 0.23
Oil, condensate and NGL ($/Bbl)	$ 0.96	$ 0.81	$ 0.82

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	2008	2007	2006
Average Production Costs ($/Mcfe)			
United States			
Lease operating costs	$ 0.89	$ 0.86	$ 0.97
Production taxes	0.44	0.31	0.28
Total production costs	$ 1.33	$ 1.17	$ 1.25
Brazil			
Lease operating costs	$ 1.64	$ 1.63	$ 0.28
Production taxes	0.58	0.51	0.53
Total production costs	$ 2.22	$ 2.14	$ 0.81
Worldwide			
Lease operating costs	$ 0.90	$ 0.88	$ 0.95
Production taxes	0.44	0.31	0.29
Total production costs	$ 1.34	$ 1.19	$ 1.24
Unconsolidated affiliate volumes (Four Star)(1)			
Natural gas (MMcf)	20,576	19,380	18,140
Oil, condensate and NGL (MBbls)	1,054	1,015	1,087
Total equivalent volumes MMcfe	26,899	25,470	24,663
MMcfe/d	74	70	68

(1) Includes our proportionate share of volumes in Four Star. In 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent.

Acquisition, Development and Exploration Expenditures

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

	2008	2007 (In millions)	2006
United States			
Acquisition Costs:			
Proved	$ 51	$ 964	$ 2

Unproved	74	262	34
Development Costs	938	735	738
Exploration Costs:			
Delay rentals	6	6	6
Seismic acquisition and reprocessing	24	19	23
Drilling	408	373	294
Asset Retirement Obligations	19	38	3
Total full cost pool expenditures	1,520	2,397	1,100
Non-full cost pool expenditures	30	13	8
Total costs incurred	$ 1,550	$ 2,410	$ 1,108
Acquisition of additional investment in Four Star[1]	$	$ 27	$
Brazil and Other International[2]			
Acquisition Costs:			
Proved	$	$	$ 2
Unproved	1	5	1
Development Costs	93	26	40
Exploration Costs:			
Seismic acquisition and reprocessing	13	6	7
Drilling	91	193	46
Asset Retirement Obligations		7	
Total full cost pool expenditures	198	237	96
Non-full cost pool expenditures	13	1	
Total costs incurred	$ 211	$ 238	$ 96

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	2008	2007 (In millions)	2006
Worldwide[2]			
Acquisition Costs:			
Proved	$ 51	$ 964	$ 4
Unproved	75	267	35
Development Costs	1,031	761	778
Exploration Costs:			
Delay rentals	6	6	6
Seismic acquisition and reprocessing	37	25	30
Drilling	499	566	340
Asset Retirement Obligations	19	45	3
Total full cost pool expenditures	1,718	2,634	1,196
Non-full cost pool expenditures	43	14	8
Total costs incurred	$ 1,761	$ 2,648	$ 1,204
Acquisition of additional investment in Four Star[1]	$	$ 27	$

(1) In 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent.

(2) Costs incurred for Egypt were $27 million, $10 million and $4 million for the years ended December 31, 2008, 2007 and 2006.

We spent approximately $141 million in 2008, $200 million in 2007 and $192 million in 2006 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each respective 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, under long-term contracts, to Petrobras, Brazil s state-owned energy company. We 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. For a further discussion of these contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of

Operations.

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

Regulatory Environment. Our natural gas and oil exploration and production activities are regulated at the federal, state and local levels, in the United States, Brazil and Egypt. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

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

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. In addition, we continue to manage and liquidate remaining legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. As of December 31, 2008, we managed the following types of contracts:

Natural gas transportation-related contracts. Our transportation contracts give us the right to transport natural gas using pipeline capacity for a fixed reservation charge plus variable transportation costs. Our ability to utilize our transportation capacity under these contracts is dependent on several factors, including the difference in natural gas prices at receipt and delivery locations along the pipeline system, the amount of working capital needed to use this capacity and the capacity required to meet our other long-term obligations. The following table details our transportation contracts as of December 31, 2008:

	Affiliated Pipelines(1)	Other Pipelines
Daily capacity (MMBtu/d)	391,000	198,000
Expiration	2010 to 2028	2012 to 2026
Receipt points / Delivery points	Various	Various

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

Legacy natural gas contracts. As of December 31, 2008, we had seven significant physical natural gas contracts with power plants associated with our legacy trading activities, including our Midland Cogeneration Venture (MCV) supply agreement. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2011 to 2028, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d.

Legacy power contracts. As of December 31, 2008, we had three derivative contracts that require us to swap locational differences in power prices between three 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 3,700 GWh from 2009 to 2012, 2,400 GWh for 2013 and 1,700 GWh from 2014 to April 2016. Additionally, these contracts require us to provide approximately 1,700 GWh of power per year and approximately 71 GW of installed capacity per year in the PJM power pool through April 2016.

Markets, Competition and Regulatory Environment

Our Marketing segment operates in a highly competitive environment, competing on the basis of price, operating efficiency, technological advances, experience in the marketplace and counterparty credit. Each market served is influenced directly or indirectly by energy market economics. Our primary competitors include major oil and natural gas producers and their affiliates, large domestic and foreign utility companies, large local distribution companies and their affiliates, other interstate and intrastate pipelines and their affiliates, and independent energy marketers and financial institutions. Our marketing activities are subject to the regulations of among others, the FERC and the Commodity Futures Trading Commission.

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Power Segment

As of December 31, 2008, our Power segment primarily included the ownership and operation of our remaining investments in international power generation and pipeline facilities listed below. The power facilities primarily sell power under long-term power purchase agreements with power transmission and distribution companies owned by local governments. The facilities are subject to regulation by government agencies in the countries where the projects are located. These regulatory structures are subject to change over time. As a result, we are subject to certain political risks related to these facilities. We continue to pursue the sale of our remaining power and pipeline investments.

Power Project	Area	El Paso Ownership Interest (Percent)	Gross Capacity (MW)	Power Purchaser	Expiration Year of Power Sales Contracts	Fuel Type
Porto Velho[(1)]	Brazil	50	404	Eletronorte	2010, 2023	Oil
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas

(1) We completed the sale of our investment in this project to our partner in February 2009. See Part II, Item 8, Financial Statements and Supplementary Data, Note 18 for a further discussion of the sale of this investment.

In addition to the international power plants above, we also have investments in two operating natural gas pipelines in South America.

Pipeline	Gross KM[(2)]	El Paso Ownership Interest (Percent)	Design Capacity[(2)] (MMcf/d)	Average 2008 Throughput[(2)] (BBtu/d)
Bolivia to Brazil	3,150	8	1,059	1,054
Argentina to Chile[(1)]	540	22	138	210

(1) We are currently in negotiations to sell our investment in

this pipeline and expect the sale to close in the first half of 2009.

(2) Amounts are not adjusted for our ownership percentage.

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, 2009, we had 5,344 full-time employees, of which 129 employees are subject to collective bargaining arrangements.

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Executive Officers of the Registrant

Our executive officers as of March 2, 2009, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	President and Chief Executive Officer of El Paso	2003	49
D. Mark Leland	Executive Vice President and Chief Financial Officer of El Paso	2005	47
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	52
Brent J. Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	47
Susan B. Ortenstone	Senior Vice President (Human Resources and Administration) of El Paso	2003	52
James C. Yardley	Executive Vice President, Pipeline Group	2005	57
James J. Cleary	President of Western Pipeline Group	2005	54

Douglas L. Foshee has been President, Chief Executive Officer and a director of El Paso since September 2003. Prior to joining El Paso, Mr. Foshee served as Executive Vice President and Chief Operating Officer of Halliburton Company having joined that company in 2001 as Executive Vice President and Chief Financial Officer. Prior to assuming his position at Halliburton, Mr. Foshee served as President, Chief Executive Officer and Chairman of the Board of Nuevo Energy Company and Chief Executive Officer and Chief Operating Officer of Torch Energy Advisors Inc. Mr. Foshee presently serves as a director of Cameron International Corporation and is a trustee of AIG Credit Facility Trust. Mr. Foshee serves on the Federal Reserve Bank of Dallas, Houston Branch as Chairman. Mr. Foshee also serves on the Board of Trustees of Rice University and serves as a member of the Council of Overseers for the Jesse H. Jones Graduate School of Management. He is a member of the Greater Houston Partnership Board and Executive Committee. In addition, Mr. Foshee serves on the boards of Central Houston, Inc., Children s Museum of Houston and the Texas Business Hall of Fame Foundation. Mr. Foshee serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

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

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 beginning in 1983. Mr. Baker serves as Executive Vice President and General Counsel of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

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 and asset management capacities for Burlington Resources Inc., including the Chief Engineering role from 2000 to 2004. He was a member of the Burlington Executive Committee from 2001 to 2006. Mr. Smolik also serves on the Boards of the American Exploration and Production Council and the Independent Petroleum Association of America.

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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 beginning in 1979. Ms. Ortenstone serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

James C. Yardley has been Executive Vice President of El Paso with responsibility for oversight of the regulated pipeline business unit since August 2006. He has served as President of Southern Natural Gas Company since May 1998 and President and Chairman of the Board of Tennessee Gas Pipeline since August 2006. Mr. Yardley has been a member of the Management Committees of both Colorado Interstate Gas Company and Southern Natural Gas Company since their conversion to general partnerships in November 2007. 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 Company and Sonat Inc. beginning in 1978. Mr. Yardley is currently a member of the board of directors of Scorpion Offshore Ltd. He also serves as Chairman of the Board of Interstate Natural Gas Association of America. Mr. Yardley serves as Director, President and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

James J. Cleary has been a director and President of El Paso Natural Gas Company since January 2004. Mr. Cleary has been a member of the Management Committee of Colorado Interstate Gas Company since November 2007 and President since January 2004. He previously served as Chairman of the Board of both El Paso Natural Gas Company and Colorado Interstate Gas Company from May 2005 to August 2006. From January 2001 to December 2003, he served as President of ANR Pipeline Company. Prior to that time, Mr. Cleary served as Executive Vice President of Southern Natural Gas Company from May 1998 to January 2001. He also worked for Southern Natural Gas Company and its affiliates in various capacities beginning in 1979. Mr. Cleary serves as Senior Vice President of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P.

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 or injuries to persons and property causing us to suffer substantial losses. Analyses performed by various governmental and private organizations indicate potential physical risks associated with climate change events (such as hurricanes, flooding, etc). Some of the studies indicate that potential impacts on energy infrastructure are highly uncertain and not well understood, including both the timing and potential magnitude of such impacts. As the science is better understood and analyzed, we will review the operational and uninsured risks to our facilities attributed to climate change.

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. In addition, there is a risk that our insurers may default on their coverage obligations. 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.

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

- service area competition;
- price competition;
- expiration or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- weather conditions that impact natural gas throughput and storage levels;

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- weather fluctuations or warming or cooling trends that may impact demand in the markets in which we do business, including trends potentially attributed to climate change;
- drilling activity and decreased availability of conventional gas supply sources and the availability and timing of other natural gas supply sources, such as LNG;
- continued development of additional sources of gas supply that can be accessed;
- decreased natural gas demand due to various factors, including economic recession (as further discussed below) and increases in prices;
- legislative, regulatory, or judicial actions, such as mandatory greenhouse gas regulations and/or legislation that could result in (i) changes in the demand for natural gas and oil, (ii) changes in the availability of or demand for alternative energy sources such as hydroelectric and nuclear power, wind and solar energy and/or (iii) changes in the demand for less carbon intensive energy sources;
- availability and cost to fund ongoing maintenance and growth projects, especially in periods of prolonged economic decline;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions including prolonged recessionary periods that might negatively impact natural gas demand and the capital markets;
- expiration and/or renewal of existing interests in real property, including real property on Native American lands; and
- unfavorable movements in natural gas prices in certain supply and demand areas.

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

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

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

Substantially all of our pipeline subsidiaries revenues are generated under transportation and storage contracts which expire periodically and must be renegotiated, extended or replaced. If we are unable to extend or replace these contracts when they expire or renegotiate contract terms as favorable as the existing contracts, we could suffer a material reduction in our revenues, earnings and cash flows. For additional information on the expiration of our contract portfolio, see Part II, Item 7, Management s Discussion and Analysis of Financial Conditions and Results of Operations. 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;

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- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or natural gas supply points;
- legislative and/or regulatory actions.

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

Revenues generated by our transportation, storage and LNG contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and LNG. Increased prices could result in a reduction of the volumes transported by our customers, including power companies that may not dispatch natural gas-fired power plants if natural gas prices increase. Increased prices could also result in industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies loss of customer base. The success of our transmission, storage and LNG operations is subject to continued development of additional gas supplies to offset the natural decline from existing wells connected to our systems, which requires the development of additional oil and natural gas reserves, obtaining additional supplies from interconnecting pipelines, and the development of LNG facilities on or near our systems. A decline in energy prices could cause a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, storage and processing through our systems.

Pricing volatility may impact the value of under or over recoveries of retained natural gas, imbalances and system encroachments. If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted on a short-term basis, as well as with respect to our long-term recontracting activities. Furthermore, fluctuations in pricing between supply sources and market areas could negatively impact our transportation revenues. Consequently, a significant prolonged downturn in natural gas and oil prices could have a material adverse effect on our financial condition, results of operations and liquidity. 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 and regulation;
- federal and state taxes, if any, on the sale or transportation of natural gas and NGL;
- abundance of supplies of alternative energy sources; and
- political unrest among countries producing oil and LNG.

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

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

- our ability to obtain necessary approvals and permits by the FERC and other regulatory agencies on a timely basis and on terms that are acceptable to us;
- the ability to access sufficient capital at reasonable rates to fund expansion projects, especially in periods of prolonged economic decline when we may be unable to access the capital markets;
- the availability of skilled labor, equipment, and materials to complete expansion projects;
- potential changes in federal, state and local statutes, regulations, and orders, including environmental requirements that prevent a project from proceeding or increase the anticipated cost of the project;

impediments on our ability to acquire rights-of-way or land rights on a timely basis or on terms that are acceptable to us;

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our ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from inflation or increased costs of equipment, materials, labor, contractor productivity or other factors beyond our control, that we may not be able to recover from our customers which may be material;

the lack of future growth in natural gas supply and/or demand; 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. There is also the risk that the downturn in the economy and its negative impact upon natural gas demand may result in either slower development in our expansion projects or adjustments in the contractual commitments supporting such projects. As a result, new facilities may be delayed or may not achieve our expected investment return, which could adversely affect our results of operations, cash flows or financial position.

Our pipeline systems depend on certain key customers and producers for a significant portion of their revenues. The loss of any of these key customers could result in a decline in our systems revenues and cash available to pay distributions.

Our systems rely on a limited number of customers for a significant portion of our systems revenues. For the year ended December 31, 2008, the four largest natural gas transportation customers for each of TGP, CIG, EPNG and SNG accounted for approximately 23%, 51%, 46% and 41% of their respective operating revenues. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts or otherwise, could have a material adverse effect on our financial condition and results of operations.

We are exposed to the credit risk of our pipeline customers and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of delays in payment as well as losses resulting from nonpayment and/or nonperformance by our pipeline customers, including default risk associated with adverse economic conditions. Our credit procedures and policies may not be adequate to fully eliminate customer credit risk. If we fail to adequately assess the creditworthiness of our existing or future customers and they fail to pay and/or perform due to an unanticipated deterioration in their creditworthiness and we are unable to remarket the capacity, our business, the results of our operations and our financial condition could be adversely affected. We may not be able to effectively remarket capacity during and after insolvency proceedings involving a shipper.

We are exposed to the credit and performance risk of our key contractors and suppliers.

As an owner of large energy infrastructure, including significant capital expansion programs, we rely on contractors for certain construction and drilling operations and we rely on suppliers for key materials and supplies, including steel mills and pipe manufacturers. There is a risk that such contractors and suppliers may experience credit and performance issues that could adversely impact their ability to perform their contractual obligations with us. This could result in delays or defaults in performing such contractual obligations, which could adversely impact our financial condition and results of operations.

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 of our exploration and production business 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 supply and/or demand for natural gas and oil especially during periods of prolonged economic decline;

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 certain foreign countries to agree to and maintain natural gas and oil prices, production and export 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, 2008 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices in the future 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 additional downward revisions of our reserves and additional full cost ceiling test write-downs of the carrying value of our natural gas and oil properties, which could be substantial, and would negatively impact our net income and stockholders equity.

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

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

- the results of future drilling activity;
- the availability and future costs of rigs, equipment and labor to support drilling activity and production operations;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;
- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive conditions from other companies;
- our ability to successfully integrate acquisitions;
- adverse changes in future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;
- increased federal or state regulations, including environmental regulations, that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- governmental action affecting the profitability of our exploration and production activities, such as increased royalty rates payable on oil and gas leases, the imposition of additional taxes on such activities or the

modification or withdrawal of tax incentives in favor of exploration and development activity;

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

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

- continued access to sufficient capital at reasonable rates to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics especially in periods of prolonged economic decline when we may be unable to access the capital markets.

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, could have material deductibles or, as in the case of environmental fines and penalties, cannot be insured which could adversely affect our future results of operations, cash flows or financial condition.

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

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

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

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

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

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

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

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

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

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

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

Our foreign operations and investments involve special risks.

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

- 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;

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changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties, nationalization, and expropriation; and

protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations.

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

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

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

Our pipeline and exploration and production businesses require the retention and recruitment of a skilled workforce including engineers and other technical personnel. If we are unable to retain our current employees (many of which are retirement eligible) or recruit new employees of comparable knowledge and experience, our business could be negatively impacted.

Risks Related to Legal and Regulatory Matters

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

We are subject to various governmental investigations from time to time, including investigations by the FERC and the U.S. Department of Transportation Office of Pipeline Safety. The results of any investigation could have a material adverse effect on our business, financial condition or results of operation.

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

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, the U.S. Department of Interior, and various state and local regulatory agencies whose actions have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services and sets authorized rates of return.

In April 2008, the FERC adopted a new policy that will allow master limited partnerships to be included in rate of return proxy groups for determining rates for services provided by interstate natural gas and oil pipelines. The FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC s policy statement concludes among other items that (i) there should be no cap on the level of distributions included in the current discounted cash flow methodology and (ii) there should be a downward adjustment to the long-term growth rate used for the equity cost of capital of natural gas pipeline master limited partnerships. Pursuant to the FERC s jurisdiction over rates, existing rates may be challenged by complaint, and proposed rate increases may be challenged by protest. A successful complaint or protest against our pipelines rates could have an adverse impact on our revenues.

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

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

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

Our operations are subject to various environmental laws and regulations regarding compliance and remediation obligations. Compliance obligations can result in significant costs to install and maintain pollution controls. In addition, although we have environmental management systems to manage our compliance obligations, fines and penalties can result 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 U.S. Environmental Protection Agency (EPA) under the Comprehensive Environmental Response, Compensation and Liability Act), as well as damage claims arising out of the contamination of properties or impact on natural resources. Although we believe we have processes and systems in place to establish appropriate reserves for our environmental liabilities, it is not possible for us to estimate the exact amount and timing of all future expenditures related to environmental matters and we could be required to set aside additional amounts which could significantly impact our future consolidated results of operations, cash flows or financial position. See Part I, Item 3, Legal Proceedings and Part II, Item 8, Financial Statements and Supplementary Data, Note 13.

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

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

In addition to potentially increasing the cost of our environmental liabilities, changing environmental laws and regulations may increase our future compliance costs, such as the costs of complying with ozone standards and potential mandatory greenhouse gas reporting and emission reductions. Future environmental compliance costs relating to greenhouse gases (GHGs) associated with our operations are not yet clear. Legislative and regulatory measures to address GHG emissions are in various phases of discussions or implementation at the international, national, regional and state levels. These measures include the Kyoto Protocol, which has been ratified by some of the international countries in which we have operations such as Mexico, Brazil, and Egypt. In the United States, various federal and state legislative proposals have been made over the last several years and it is possible that legislation may be enacted in the future that could negatively impact our operations and financial results. The level of such impact will likely depend upon whether any of our facilities will be directly responsible for compliance with GHG regulations and legislation; whether federal legislation will preempt any potentially conflicting state/regional GHG programs; whether cost containment measures will be available; the ability to recover compliance costs from our customers; and the manner in which allowances are provided. At the federal regulatory level, the EPA has requested public comments on the potential regulation of GHGs under the Clean Air Act. Some of the regulatory alternatives identified by the EPA in its request for comments, if eventually promulgated as final rules, would likely impact our operations and financial results. It is uncertain whether the EPA will proceed with adopting final rules or whether the regulation of GHGs will be addressed in federal and state legislation.

Legislation and regulation are also in various stages of discussion or implementation in many of the states and regions in which we operate, including in the western U.S. where the Western Climate Initiative (WCI) proposes to institute a cap-and-trade program and target emission reductions. There is uncertainty regarding whether and to what extent each member state will adopt the WCI recommendations, and the details of the programs as eventually adopted may differ significantly among the member states. In addition, California has separately enacted legislation that imposes GHG emission reductions. However, California s governing state regulatory agency must enact implementing regulations to define the scope of the coverage, the compliance schedule and other relevant provisions governing GHG emissions. Therefore, it is not yet possible to determine whether the regulations implementing the WCI recommendation or the California legislation will be material to our operations or our financial results.

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

Although it is uncertain what impact these legislative, regulatory, and judicial actions might have on us until further definition is provided in those forums, there is a risk that such future measures could result in changes to our operations and to the consumption and demand for natural gas and oil. Changes to our operations could include increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, (iii) construct new facilities, (iv) acquire allowances to authorize our GHG emissions, (v) pay any taxes related to our GHG emissions and (vi) administer and manage a GHG emissions program. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental and GHG compliance in the rates charged by our pipelines and in the prices at which we sell natural gas and oil, our ability to recover such costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final regulations and legislation.

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

We are involved in various lawsuits in which we or our subsidiaries have been sued (see Part II, Item 8, Financial Statements and Supplementary Data, Note 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 El Paso s senior unsecured indebtedness are below investment grade, currently rated Ba3 with a stable outlook by Moody s Investor Service (Moody s) and BB- with a negative outlook by Standard & Poor s. These ratings have increased our cost of capital and our operating costs. There is a risk that these credit ratings may be adversely affected in the future as the credit rating agencies continue to review our leverage, liquidity and credit profile. Any reduction in our credit rating could impact our ability to access the capital markets, as well as our cost of capital. As a result of the volatility in the financial markets and the capital commitments of our pipeline group, we have been maintaining greater liquidity levels. However, if commodity prices remain at current levels or continue to decline and our access to capital markets is restricted, then such liquidity levels may not be adequate to manage our business and 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, including debt to EBITDA covenants in our revolving credit agreement, and contain cross default provisions. In light of the volatility in the financial markets and a reduction in access to capital, these covenants may become more restrictive over time. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we might not be able to repay such debt and other financing obligations.

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

Adverse general global economic conditions could negatively affect our operating results, financial condition, liquidity or our share price.

We are subject to the risks arising from adverse changes in general global economic conditions including recession or economic slowdown. Recently, the global economy has experienced a recession and the financial markets have experienced extreme volatility and instability. As a result, we announced reductions in our capital plan as well as several other potential actions, which could include non-core asset sales to address these general economic conditions or obtaining partners on one or more pipeline expansion projects. Adverse general economic conditions as well as restrictions on the ability of parties to access capital markets could negatively impact our ability to sell such assets or obtain partners on such projects on a timely basis, as well as negatively impact the amount of proceeds from such sales or joint venture arrangements.

If we experience prolonged periods of recession or slowed economic growth in the U.S., demand growth from consumers for natural gas and oil produced and transported by us on our natural gas transportation systems may continue to decrease, which could impact the development of our future expansion projects. Additionally, our access to capital could continue to be impeded and the cost of capital we obtain could be higher. We are subject to the risks arising from changes in legislation and regulation associated with any such recession or prolonged economic slowdown, including creating preferences for renewables, as part of a legislative package to stimulate the economy. In addition, the general volatility in the financial markets and the economy may also affect the return expectations of our investors and could adversely impact the value of our securities. Finally, our pension plans were underfunded at December 31, 2008, due primarily to the recent adverse economic conditions. While we do not currently expect to make additional contributions in 2009, we may be required to make additional pension plan contributions in the future if adverse economic conditions continue. Any of these events, which are beyond our control, could negatively impact our business, results of operations, financial condition, and liquidity.

We are subject to financing and interest rate risks.

Our future success, financial condition and liquidity could be adversely affected based on our ability to access capital markets and obtain financing at cost effective rates. This is dependent on a number of factors in addition to general economic conditions discussed above, 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.

Although a substantial portion of our debt capital structure has fixed interest rates, changes in interest rates could cause our financing costs to increase. Rising interest rates could also negatively impact our investment in El Paso Pipeline Partners as changes in interest rates may affect the yield requirements of investors in its units.

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Our available liquidity could be impacted by decreases in our natural gas and oil reserves under our borrowing base facility of our exploration and production subsidiary.

We maintain $1.3 billion of our liquidity through the borrowing base facilities of our exploration and production subsidiary. A downward revision of our natural gas and oil reserves, due to future declines in commodity prices, performance revisions or otherwise, could require a redetermination of the borrowing base and could negatively impact our ability to source funds from such facilities in the future.

Our ability to sell assets or obtain partners on projects to maintain adequate liquidity may be impacted by adverse general economic conditions.

In order to maintain adequate levels of liquidity, it is possible that we may be required to sell assets or obtain partners on projects, including one or more of our pipeline expansion projects. Adverse general economic conditions as well as restrictions on the ability of parties to access capital markets could negatively impact our ability to sell such assets or obtain partners on such projects on a timely basis, as well as negatively impact the amount of proceeds from such sales or joint venture arrangements.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

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

ITEM 3. LEGAL PROCEEDINGS

Details of the cases listed below, as well as a description of our other legal proceedings are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 13, and are incorporated herein by reference.

Natural Buttes. In May 2004, the EPA issued a Compliance Order to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. In September 2005, the matter was referred to the U.S. Department of Justice (DOJ). CIG entered into a tolling agreement with the United States and conducted settlement discussions with the DOJ and the EPA. While conducting some testing at the facility, CIG discovered that three generators installed in 1992 may have been emitting oxides of nitrogen at levels which suggested the facility should have obtained a Prevention of Significant Deterioration (PSD) permit when the generators were first installed, and CIG promptly reported those test data to the EPA. We have reached an agreement with the DOJ under which we will pay a total of $1.02 million to settle all of these Title V and PSD issues at the Natural Buttes Compressor Station and, in addition, we will conduct ambient air monitoring in the Uintah Basin for a period of two years. We are working with the DOJ to draft and finalize a definitive settlement agreement. In January 2009, CIG filed an application with the FERC to abandon the facilities by sale.

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

None.

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PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of February 23, 2009, we had 31,315 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
2008			
Fourth Quarter	$12.57	$ 5.32	$0.05
Third Quarter	22.47	11.25	0.05
Second Quarter	22.10	15.80	0.04
First Quarter	18.27	14.83	0.04
2007			
Fourth Quarter	$18.37	$15.29	$0.04
Third Quarter	18.56	15.00	0.04
Second Quarter	17.43	14.41	0.04
First Quarter	15.66	13.71	0.04

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2003 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 2008 included the following companies: Anadarko Petroleum Corp., Apache Corp., CenterPoint Energy Inc., Chesapeake Corp., Devon Energy Corp., Dominion Resources, Inc., Enbridge, Inc., EOG Resources Inc., Equitable Resources, Inc., National Fuel Gas Co., Newfield Exploration Co., NiSource, Inc., Noble Energy, Inc., ONEOK, Inc., Pioneer Natural Resources Co., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., TransCanada Corp., Williams Companies, Inc., and XTO Energy Inc. Our peer group for 2007 included PG&E Corp. and PPL Corp. and the companies listed above excluding, Chesapeake Energy Corp., EOG Resources Inc., National Fuel Gas Co., Newfield Exploration Co., Noble Energy, Inc., Pioneer Natural Resources Co. and XTO Energy Inc.

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COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS

	12/03	12/04	12/05	12/06	12/07	12/08
El Paso Corporation	$100	$129.40	$153.48	$195.07	$222.26	$102.42
S&P 500 Stock Index	$100	$110.88	$116.33	$134.70	$142.10	$ 89.53
S&P 500 Oil & Gas Storage & Transportation Index(1)	$100	$139.91	$184.82	$219.84	$251.14	$124.82
New Peer Group	$100	$128.47	$179.67	$193.25	$248.82	$163.03
Old Peer Group	$100	$125.49	$163.97	$185.25	$232.93	$159.00

(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 10, 2009, we declared a quarterly dividend of $0.05 per share of our common stock, payable on April 1, 2009, to shareholders of record as of March 6, 2009. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

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Unregistered Sales of Equity Securities and Use of Proceeds. The following table summarizes our purchases of common stock during the year ended December 31, 2008:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program
Year Ended December 31, 2008[(1)]	4,663,053	$ 16.62	4,663,053	$ 222,511,157

(1) On May 14, 2008, the Board approved a $300 million stock repurchase program to be consummated to the extent that we generate cash in excess of that originally planned. The share repurchase program was publicly announced on May 15, 2008 and has no stated expiration date. There was no activity in the fourth quarter of 2008.

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 we are unable to comply with our fixed charge ratio, our ability to pay additional dividends would be restricted.

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

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ITEM 6: SELECTED FINANCIAL DATA

The following selected historical financial data is derived from our audited consolidated financial statements for El Paso and its subsidiaries and is not necessarily indicative of results to be expected in the future. The selected financial data should be read together with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8, Financial Statements and Supplementary Data included in this Report on Form 10-K.

	As of or for the Year Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 5,363	$ 4,648	$ 4,281	$ 3,359	$ 4,783
Income (loss) from continuing operations	$ (823)	$ 436	$ 531	$ (506)	$ (1,032)
Net income (loss) available to common stockholders	$ (860)	$ 1,073	$ 438	$ (633)	$ (947)
Basic earnings (loss) per common share from continuing operations	$ (1.24)	$ 0.57	$ 0.73	$ (0.82)	$ (1.61)
Diluted earnings (loss) per common share from continuing operations	$ (1.24)	$ 0.57	$ 0.72	$ (0.82)	$ (1.61)
Cash dividends declared per common share	$ 0.18	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Basic average common shares outstanding	696	696	678	646	639
Diluted average common shares outstanding	696	699	739	646	639
Financial Position Data:					
Total assets	$23,668	$24,579	$27,261	$31,840	$31,398
Long-term financing obligations, less current maturities	12,818	12,483	13,329	16,282	17,506
Minority interests	561	565	31	31	367
Stockholders equity	4,035	5,280	4,186	3,389	3,438

Factors Affecting Trends. In the fourth quarter of 2008, we recorded non-cash full cost ceiling test charges of $2.7 billion as a result of the decline in commodity prices. In 2007, we sold our ANR pipeline system and related assets and also completed the offering of common units in EPB, our master limited partnership. Prior to 2006, our financial position and operating results were substantially affected by the restructuring and realignment of our business around our core pipeline and exploration and production operations. Accordingly, we sold a substantial amount of non-core assets to reduce our long-term financing obligations resulting in a significant reduction of our net income during the years ended December 31, 2004 and 2005. We recorded net pretax charges of approximately $0.1 billion in 2005 and $1.1 billion in 2004, primarily as a result of losses and impairments of assets and equity investments, restructuring charges, and settling litigation.

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

Overview

Our Management s Discussion and Analysis (MD&A) should be read in conjunction with our consolidated financial statements and the accompanying footnotes. MD&A includes forward-looking statements that are subject to risks and uncertainties that may result in actual results differing from the statements we make. These risks and uncertainties are discussed further in Item 1A, Risk Factors. Listed below is a general outline of our MD&A:

Our Business includes a summary of our business purpose and description, factors influencing profitability, a summary of our 2008 performance and an outlook for 2009;

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

Liquidity and Capital Resources includes a general discussion of our sources and uses of cash, available liquidity, our liquidity outlook for 2009, an overview of cash flow activity during 2008, and additional factors that could impact our liquidity;

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

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

Our Business

Our business purpose is to provide natural gas and related energy products in a safe, efficient and dependable manner. We own or have interests in North America s largest interstate natural gas pipeline systems that provides a stable base of earnings and cash flow with a significant backlog of committed expansion projects. We are also a large independent natural gas and oil producer focused on generating competitive financial returns 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.

Factors Influencing Our Profitability. Our pipeline operations are rate-regulated and accordingly we generate profit based on our ability to earn a return in excess of our costs through the rates we charge our customers. Our exploration and production operations generate profits dependent on the prices for natural gas and oil, our costs to explore, develop, and produce natural gas and oil, and the volumes we are able to produce, among other factors. While current volatility in the financial markets described further below could influence our near-term profitability, our long-term profitability in each of our operating segments will be primarily influenced by the following factors:

Pipelines

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

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Exploration and Production

Long-term growth of our natural gas and oil proved reserve base and production volumes through successful drilling programs and/or acquisitions;

Finding and producing natural gas and oil at a reasonable cost; and

Managing price risks to optimize realized prices on our natural gas and oil production.

In addition to these factors, our future profitability will also be affected by any impacts of the volatility in the current financial and commodity markets, by our debt level and related interest costs, the successful resolution of our historical contingencies and completing the orderly exit of our remaining power assets, historical derivative contracts and other remaining non-core assets.

Summary of 2008 Financial and Operational Performance

During 2008, our pipeline operations continued to provide a strong base of earnings and cash flow and in the first half of 2008 while, our exploration and production business benefited from a favorable commodity price environment. However, during the second half of 2008, earnings in our exploration and production business were negatively affected by the adverse impacts on production volumes of Hurricanes Ike and Gustav and a decline in commodity prices. In the fourth quarter of 2008, we recorded non-cash full cost ceiling test charges of $2.7 billion in our domestic and Brazilian full cost pools as a result of this decline in commodity prices.

Our 2008 financial performance was also impacted by favorable resolution of certain litigation and other matters which was largely offset by losses in our Marketing segment from changes in natural gas and oil prices and a decline in interest rates.

The following table provides significant operational highlights of our core businesses in 2008:

Area of Operations	**Significant Highlights**
Pipelines	Completed several pipeline projects and entered into new expansion projects including our Ruby pipeline project, TGP 300 Line project and FGT phase VIII Project resulting in a current backlog of committed growth projects of approximately $8 billion
	Placed several expansion projects in service including the WIC Kanda lateral, Phase II of the Cypress pipeline project, Cheyenne Plains compression expansion, Southeast Supply Header Phase I expansion, Medicine Bow expansion, High Plains Pipeline, and Bluewater reconfiguration project
Exploration and Production	Achieved an overall drilling success rate of 98 percent
	Advanced growth opportunities domestically in the Niobrara Shale in the Raton Basin, the Haynesville Shale in Arklatex and the Altamont field in the Rockies and internationally through our exploration programs in Brazil and Egypt. In 2008 and early 2009, we executed a unitization agreement and gas and condensate sales agreements with Petrobras to develop the Camarupim Field in Brazil
	High graded our asset portfolio through the sale of certain non-core properties (primarily in our Texas Gulf Coast and Gulf of Mexico regions) and acquired interests in domestic natural gas and oil properties in the Western region that complement our existing asset portfolio
	Managed price risk through derivative contracts which, when combined with our other positions, provided higher realized commodity prices in 2008 and gives us price protection

on a significant portion of our planned 2009 equivalent production

In our non-core Power segment we sold or transferred several international power investments. In February 2009, we completed the sale of our interest in the Porto Velho power generation facility to our partner. See Item 8, Financial Statements and Supplementary Data, Note 18 for a further discussion of the sale of this investment.

Outlook for 2009

We expect that our pipeline operations will continue to provide a strong base of earnings and operating cash flow in 2009 and anticipate spending approximately $1.7 billion in capital expenditures in this business. In our pipeline business, approximately three-fourths of the revenues are collected in the form of demand or reservation charges which are not dependent upon commodity prices or throughput levels. Also, we expect to have relatively stable rates within our pipeline group, with the majority of our pipelines not having any outstanding rate cases pending before the FERC. We expect two of our pipelines, EPNG and SNG, will be involved in major rate cases in 2009 and we expect those rate cases to result in increased revenues. Finally, we will remain focused on implementing the approximate $8 billion backlog of new committed pipeline growth projects, with several of those projects expected to commence service in 2009.

In our exploration and production business, we expect to generate significant operating cash flow and earnings, although additional non-cash ceiling test charges could impact our earnings in the future as a result of declines in natural gas and oil prices, as they have since December 31, 2008. Reductions in oilfield service costs could partially mitigate the impacts of the commodity price declines. In this business, we have reduced our capital expenditure program for 2009 to a range of $0.9 billion to $1.3 billion from $1.7 billion in 2008. Additionally, current commodity prices remain volatile and at lower levels than we have experienced over the last several years; however, we have financial derivative contracts in place for 2009 providing an average floor price of $9.02 per MMBtu for 176 TBtu of natural gas that will greatly mitigate our natural gas price risk for 2009. We also expect reductions in oilfield service costs in 2009 to the extent that commodity prices and drilling activities remain at lower levels. Although it will also impact our near-term growth profile, the objective of our capital program is to retain substantially all of our existing inventory for future exploration and production when commodity prices return to more favorable levels.

In response to our anticipated 2009 capital requirements and debt maturities, since November 2008 we have successfully generated additional liquidity of approximately $1.9 billion. During this time we completed various debt offerings including $1.2 billion raised through three separate capital market transactions, entered into new credit facilities, and completed non-core asset sales as further described in *Liquidity and Capital Resources*. As a result, we have available liquidity as of February 27, 2009 of $3.3 billion to carry us into 2010. See *Liquidity and Capital Resources* below for additional detail. Based on the completion of these activities, we do not expect to have to further access the capital markets for the remainder of 2009, regardless of whether we are successful in obtaining equity partners on any of our capital projects. However, we will continue to be opportunistic in building liquidity when prudent to meet our long-term capital needs.

We have also implemented various cost saving measures to reduce our capital, operating, as well as general and administrative costs. These measures include reducing drilling activity in our exploration and production business in the first half of 2009 until we expect to obtain further reductions in oilfield service costs later in 2009. These measures also include obtaining supply chain management savings with regard to our capital and maintenance programs, renegotiating contracts with contractors, suppliers and service providers, as well as deferring and eliminating various discretionary costs.

The extreme volatility in the financial markets, the energy industry and the global economy will likely continue to impact our outlook for 2009. First, the global financial markets continue to remain extremely volatile and it is uncertain whether recent U.S. and foreign government actions will successfully restore confidence and liquidity in the global financial markets. This could impact our longer-term access to capital for future growth projects as well as the cost of such capital, and may require us to further adjust our current financing and business plans. Second, commodity prices for natural gas and oil remain volatile and at levels substantially below those experienced prior to the fourth quarter of 2008. We may be required to record additional ceiling test charges in the future unless commodity prices significantly increase or oilfield service costs significantly decrease from their current levels. Approximately three-fourths of our domestic natural gas production in 2009 is hedged and is therefore not subject to commodity price exposure. However, we do not currently have substantial hedges in place for 2010 and beyond. Third, while the impacts are difficult to quantify at this point, a downward trend in the global economy could have adverse impacts on natural gas consumption and demand. Although all sectors could be impacted, it is likely industrial demand for energy would be impacted first in any prolonged downturn in the economy.

Based on these conditions, our plans for 2009 include:

Capital Expenditures. Planned 2009 capital expenditures between approximately $2.6 billion to $3.1 billion, with $1.7 billion of capital being spent in our pipeline business and $0.9 billion to $1.3 billion in our exploration and production business. Our $1.7 billion of planned pipeline capital reflects equity partnering on one or more of our expansion projects.

Asset Sales. We have sold or are evaluating the sale of several non-core assets generating cash proceeds of approximately $0.4 billion in 2009, of which approximately $0.2 billion have already been completed.

Other Liquidity Sources. We will continue to be opportunistic in generating additional liquidity. In February 2009, we settled our 2009 crude oil production hedges generating $186 million of cash. Additionally, to the extent any of the asset sales or partnering opportunities on expansion projects are delayed or cannot be completed, there is a further decline in commodity prices or we experience other major disruptions in the financial markets, we could also pursue other alternatives, including additional reductions in our discretionary capital program, additional secured financing arrangements, seeking additional partners for one or more of our other growth projects or selling additional non-core assets.

Our 2009 plans were determined based on a number of factors, the most significant of which are noted below:

Debt Capital Structure. Our debt capital structure is 80 percent fixed interest rates and 20 percent floating interest rates. Accordingly, we believe we have lessened exposure to market changes in interest rates on our existing debt which impact our interest costs.

Revenue and Price Sensitivities. In our pipeline business, approximately three-fourths of our pipeline revenues are collected in the form of demand or reservation charges. As a result, near-term declines in demand for natural gas due to recessionary pressures or declines in natural gas prices do not significantly impact pipeline revenues. Our exploration and production business, however, is impacted by fluctuations in commodity prices, although this is mitigated somewhat by derivative contracts in place in 2009 representing approximately 75 percent of our domestic natural gas production. Additionally, in the event of lower oil or natural gas prices, we currently have unencumbered exploration and production properties and reserves that we could pledge as collateral to maintain our current available borrowing base under the revolving credit facilities at our exploration and production subsidiary.

Counterparty Risk. We continually monitor the financial situation of our major lenders, trading counterparties, customers, joint interest partners, vendors and suppliers, and enforce our contractual rights with regard to providing collateral or credit. Certain of our contractual arrangements with such parties include requirements to provide letters of credit, performance bonds or other assurances of performance to mitigate, in part, the risk of non-performance by such parties. However, our natural gas and oil hedges executed in our exploration and production business do not contractually require the posting of margin.

Lending Institutions. As part of our determination of available capacity under our credit agreements, we completed an assessment of our available lenders under these facilities, which is a diverse group. Based on our assessment, we have determined the potential exposure to a loss of available capacity to be approximately $28 million from El Paso s $1.5 billion revolving credit facility, approximately $2 million from EPEP s $1.0 billion revolving credit facility, and approximately $15 million under EPB s $750 million credit facility. This assessment was based upon the fact that one of our lenders has failed to fund previous requests under these facilities and has filed for bankruptcy.

Our 2009 plans are designed to address the impacts of the current volatility in the global financial markets and to maintain sufficient liquidity to meet 2009 debt maturities and fund our 2009 capital program. Additionally, they are designed to retain our long-term growth potential, including our committed pipeline project backlog and our core domestic and international drilling programs, as well as our natural gas and oil resource inventory positions. In light of the current volatility of the financial markets, the energy industry and the global economy, it is possible additional adjustments to our plan and outlook will be required which could impact our financial and operating performance.

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Results of Operations

Overview

As of December 31, 2008, our core operating business segments were Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages our legacy trading activities and a Power segment that has interests in assets in South America and Asia. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets all of which are immaterial.

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

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

	2008	2007	2006
		(In millions)	
Segment			
Pipelines	$ 1,273	$ 1,265	$ 1,187
Exploration and Production	(1,448)	909	640
Marketing	(104)	(202)	(71)
Power	1	(37)	82
Segment EBIT	(278)	1,935	1,838
Corporate and other	124	(283)	(88)
Consolidated EBIT	(154)	1,652	1,750
Interest and debt expense	(914)	(994)	(1,228)
Income taxes	245	(222)	9
Income (loss) from continuing operations	(823)	436	531
Discontinued operations, net of income taxes		674	(56)
Net income (loss)	$ (823)	$ 1,110	$ 475

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

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Pipelines Segment

Overview

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

Type	Description	Percent of Total Revenues
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline systems, storage facilities or LNG terminalling facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts.	76
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.	24

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, changes in supply and demand, regulatory actions, competition, weather and declines in the creditworthiness of our customers. We also experience earnings volatility at certain pipelines when the amount of natural gas used in operations differs from the amounts we receive for that purpose.

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

We continue to manage our recontracting process to limit the risk of significant impacts on our revenues from expiring contracts. Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the maximum allowable rates allowed under our tariffs, although at times, we enter into contracts at less than these maximum allowable rates to remain competitive. We refer to the difference between the maximum rates allowed under our tariff and the contractual rate we charge as discounts . Our existing contracts mature at various times and in varying amounts of throughput capacity. The weighted average remaining contract term for active contracts is approximately six years as of December 31, 2008. Below are the contract expiration portfolio and the associated revenue expirations for our firm transportation contracts on our wholly and majority owned systems as of December 31, 2008, including those with terms beginning in 2009 or later:

	Percent of Total	Percent of Total

	BBtu/d	Contracted Capacity	Reservation Revenue	Reservation Revenue
			(In millions)	
2009	2,600	10	$ 151	7
2010	3,497	13	287	14
2011	3,104	12	294	15
2012	3,928	15	241	12
2013	3,278	13	248	12
2014 and beyond	9,613	37	819	40
Total	26,020	100	$ 2,040	100

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Summary of Operational and Financial Performance

In 2008, we continued to deliver strong operational and financial performance across all pipelines. We placed several expansion projects in service including the WIC Kanda lateral project in January, Phase II of the Cypress project in May, the Cheyenne Plains compression expansion project in August, Phase I of the Southeast Supply Header project in September, the Medicine Bow expansion in October and the High Plains Pipeline in November, and continued to make significant progress on our backlog of expansion projects. In September 2008, we contributed additional interests in CIG and SNG to El Paso Pipeline Partners, L.P. (EPB), our master limited partnership, as further discussed in Part I, Item 1, Business. At December 31, 2008, our ownership interest in EPB consists of a two percent general partner interest and a 72 percent limited partner interest.

During 2008, we benefited from (i) higher realized rates and demand on certain of our systems, (ii) increased throughput and (iii) increased activity under other various interruptible services. The level of throughput on our systems can provide evidence of the underlying long-term value of our system capacity. In 2008, increased throughput in certain of our systems was primarily a result of increased demand for California deliveries and higher production activities from our Rockies-related expansions. However, we expect growth of the natural gas market will be adversely affected by the current economic recession in the U.S. and global economies. The decline in economic activity will reduce industrial demand for natural gas and electricity, which will cause lower natural gas demand both directly in end-use markets and indirectly through lower power generation demand for natural gas. The demand for natural gas and electricity in the residential and commercial segments of the market will likely be less affected by the economy. The lower demand and the credit restrictions on investments in the current environment may also slow development of supply projects. As a result, our pipelines may experience lower throughput, lower revenues and slower development of new expansion projects. While our pipeline systems could experience some level of reduced throughput and revenues, or slower development of expansion projects as a result of these factors, each generates a significant portion of their revenues through monthly reservation or demand charges on long-term contracts at rates stipulated under our tariffs. Additionally, we do not expect production the U.S. Rocky Mountain region to significantly decrease from current levels due to the need to replace diminishing exports from Canada and declining production from traditional domestic sources.

During 2009, we plan to spend $1.7 billion in capital, of which $1.3 billion will be designated for our backlog of expansion projects. Our $1.7 billion of planned pipeline capital expenditures anticipates obtaining approximately $0.5 billion of capital from equity partners on one or more of our expansion projects. We intend to build on the growth achieved in 2008 and currently have approximately $8 billion in committed expansion projects that comprise our backlog. El Paso s committed backlog of new pipeline growth projects are substantially fully contracted with customers and will be placed in service over the next five years. Listed below are the projects that comprise our backlog grouped by anticipated in-service dates as of December 31, 2008:

Project	Anticipated In-Service Dates	Estimated Costs (in millions)	FERC Approved
2009:			
Carthage Expansion	May 2009	$ 39	Yes
Totem Gas Storage (50%)(1)	July 2009	77	Yes
Concord Lateral Expansion	November 2009	21	Yes
WIC Piceance Lateral Expansion	October 2009	62	Yes
2010 and Beyond:			

CIG Raton 2010 Expansion	June 2010		146	No
WIC System Expansion[2]	Various		71	No
Cypress Phase III[3]	First half of 2011		86	Yes
Ruby Pipeline[5]	First Quarter of 2011		3,000	No
FGT Phase VIII Expansion (50%)[1][5]	April 2011		1,200	No
Gulf LNG Clean Energy (50%)[4] [1]	October 2011		797	Yes
TGP 300 Line Expansion	November 2011		750	No
Elba Expansion III and Elba Express	2010-2014		1,120	Yes
South System III and Southeast Supply Header Phase II	2011-2012		421	No
Total Committed Expansion Backlog		$	7,790	

(1) Amounts represent our share of the estimated costs.

(2) This expansion consists of two projects with separate in-service dates of November 2010 and March 2011.

(3) Construction of Cypress Phase III is at the option of BG LNG Services.

(4) Includes approximately $295 million that we paid to acquire a 50 percent interest in this project.

(5) Although these projects have substantial contractual commitments with customers, they are not fully contracted.

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Listed below are additional updates to significant backlog projects or significant projects added to our backlog in 2008:

South System III. The South System III expansion project will be completed in three phases. During the second quarter of 2008, we changed the scope of this project at the request of the customer which increased the total estimated cost to $352 million. We filed an application with the FERC in December 2008 for certificate authorization to construct and operate these facilities.

Southeast Supply Header. We own an undivided interest in the northern portion of the Southeast Supply Header project jointly owned by Spectra Energy Corp. (Spectra) and Centerpoint Energy. The construction of this project is managed by Spectra and our share of the estimated cost for this project is $241 million. This project is expected to be completed in two phases. Phase I of the project was completed in September 2008. In December 2008, we filed an application with the FERC for certificate authorization to construct Phase II, which is anticipated to be complete in June 2011.

Florida Gas Transmission Phase VIII. We have a 50 percent interest in this project through our equity investment in Citrus. Our proportional share of the estimated cost of this project increased in 2008 to $1.2 billion due to higher than expected pipe and other costs.

CIG Raton 2010 Expansion. In July 2008, we announced the expansion of the CIG Raton Basin Pipeline extending from the Raton Basin Wet Canyon Lateral to the south end of the Valley Line. The tentative FERC filing date for this project is March 2009.

Ruby Pipeline Project. In 2008, we obtained sufficient long-term capacity commitments from customers and committed to move forward with the $3 billion Ruby Pipeline project. We filed a certificate application with the FERC in January 2009. We have ordered all of the pipe for our Ruby Pipeline project on a fixed price basis which will be recoverable through future rates when the project is placed in service.

TGP 300 Line Expansion. In August 2008, we announced our 300 Line expansion project with an estimated total capital cost of approximately $750 million. We have ordered all of the pipe for our TGP 300 Line expansion project on a fixed price basis which will be recoverable through future rates when the project is placed in service.

Gulf LNG Clean Energy. In February 2008, we completed our acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, which is constructing a FERC approved liquefied natural gas terminal in Pascagoula, Mississippi.

Successful execution on our $8 billion committed pipeline backlog will require effective project management. In addition, effective supply chain sourcing will also be important to not only control costs but to also seek cost reductions in light of the downturn in demand for certain supplies and services. See *Liquidity and Capital Resources* for a further description of our pipeline backlog.

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Operating Results

	2008	2007	2006
	(In millions, except volumes)		
Operating revenues	$ 2,684	$ 2,494	$ 2,402
Operating expenses	(1,532)	(1,383)	(1,339)
Operating income	1,152	1,111	1,063
Other income	156	157	124
EBIT before minority interests	1,308	1,268	1,187
Minority interests	(35)	(3)	
EBIT	$ 1,273	$ 1,265	$ 1,187
Throughput volumes (BBtu/d)(1)			
TGP	4,864	4,880	4,534
EPNG and MPC	4,422	4,216	4,255
CIG, WIC and CPG	5,376	4,906	4,301
SNG	2,339	2,345	2,167
Other	50	50	50
Equity investments(2)	1,763	1,734	1,705
Total throughput	18,814	18,131	17,012

(1) Volumes exclude intrasegment activities.

(2) Represents our proportional share.

The table below and discussion that follows detail the impact on EBIT of significant events in 2008 compared with 2007 and 2007 as compared with 2006. We have also provided an outlook on events that may affect our operations in the future.

	2008 to 2007 Variance				2007 to 2006 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 74	$ (26)	$ 19	$ 67	$ 50	$ (7)	$ 9	$ 52
Reservation and usage revenues	67			67	31			31
Gas not used in operations and	33	(13)		20	3	(16)		(13)

revaluations								
Bankruptcy settlements	27	1		28		(3)		(3)
Operating and general and administrative expense		(62)		(62)		(35)		(35)
Gain/loss on long-lived assets		(31)	1	(30)		4	(2)	2
Hurricanes	(10)	(14)		(24)		12		12
Equity earnings from Citrus			(17)	(17)			19	19
Minority interests			(32)	(32)			(3)	(3)
Other[1]	(1)	(4)	(4)	(9)	8	1	7	16
Total impact on EBIT	$ 190	$ (149)	$ (33)	$ 8	$ 92	$ (44)	$ 30	$ 78

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

Expansions. During 2008 and 2007, our reservation revenues and throughput volumes increased due to projects placed in service. In 2008, we placed several expansion projects in service including the WIC Kanda lateral project in January, Phase II of the Cypress project in May, the Cheyenne Plains compression expansion project in August, Phase I of the Southeast Supply Header project in September, the Medicine Bow expansion in October and the High Plains Pipeline in November. During 2007, we placed several expansion projects in service including Phase I of the Cypress project, the Louisiana Deepwater Link project, the Triple-T Extension project, the Northeast Connexion-New England project and the Mexico LPG Burgos project.

Reservation and Usage Revenues. During the year ended December 31, 2008, our EBIT was favorably impacted by:

- increased demand for off-system and mainline capacity on our Rocky Mountain region systems primarily due to lower natural gas prices in the Rocky Mountains as compared to other regions in the United States;
- additional firm capacity sold in the northern and southern regions of our TGP system, partially offset by lower surcharges from certain firm customers on this system ;
- increased reservation and usage revenues on our EPNG system due to higher amounts charged on recontracted capacity in Arizona and California; and
- additional interruptible and firm commodity services provided in several of our pipeline systems.

The increase in our reservation and usage revenues in 2007 compared with 2006 was primarily due to:

- an increase in throughput on our pipeline systems, primarily in the Rocky Mountains and southern regions which increased due to new supply, colder weather and increased transportation services to power plants;
- additional firm capacity sold in the south central region of our TGP system; and
- increased rates on our CIG system effective October 2006 as a result of CIG s rate settlement.

Gas Not Used in Operations and Revaluations. During the year ended December 31, 2008, our EBIT was favorably impacted by higher volumes of gas not used in our TGP operations compared with the same period in 2007. During 2008, CIG and WIC implemented FERC-approved fuel and related gas cost recovery mechanisms designed to recover all cost impacts, or flow through to shippers any revenue impacts, of certain fuel imbalance revaluations and related gas balance items and should reduce earnings volatility resulting from these items over time. We anticipate that the overall activity in this area will continue to vary based on factors such as volatility in natural gas prices, the efficiency of our pipeline operations, regulatory actions and other factors.

During the year ended December 31, 2007, our EBIT was unfavorably impacted by the revaluation of net gas imbalances and other gas owed to our customers in our CIG and WIC systems as a result of increasing natural gas prices in 2007 versus decreasing natural gas prices in 2006 and lower processing revenues and operational gas costs on our CIG system due to a decrease in processing volumes and natural gas liquids. Partially offsetting these unfavorable impacts in 2007 were higher volumes of gas not used in TGP s operations.

Bankruptcy Settlements. During 2008, our revenue increased by $33 million related to distributions received under Calpine Corporation s (Calpine) approved plan of reorganization. This settlement was related to Calpine s rejection of its transportation contracts with us. During 2008, 2007 and 2006, we recorded income of approximately $10 million, $5 million and $18 million, net of amounts potentially owed to certain customers, related to amounts recovered from the Enron bankruptcy settlement. In 2007, we received $10 million to settle our bankruptcy claim against USGen New England, Inc.

Operating and General and Administrative Expenses. During the year ended December 31, 2008, our operating and general and administrative expenses were higher than in 2007 primarily due to increased labor costs to support our growth and customer activities and additional maintenance work required on several of our pipeline systems. During the year ended December 31, 2007, our operating and general and administrative expenses were higher than in 2006 primarily due to increased insurance costs for wind damage on our pipeline assets located primarily in the Gulf of Mexico region, increased repair and maintenance costs, allowances for non-trade accounts receivable and environmental reserves.

Gain/Loss on Long-Lived Assets. During 2008, we recorded impairments of $41 million, including an impairment related to our Essex-Middlesex Lateral project due to a prolonged permitting process and an impairment of our EPNG Arizona gas storage projects that we are no longer developing due to declining real estate values. During 2007, we recorded (i) a $10 million impairment of certain pipeline assets originally purchased to repair certain offshore hurricane damage following a decision not to use these assets, (ii) a loss of approximately $9 million on EPNG s East

Valley Line Lateral pursuant to a FERC determination on the accounting treatment for the pending sale of certain transmission facilities and (iii) a $7 million pre-tax gain on the sale of a pipeline lateral. During 2006, we recorded impairments of $16 million due to discontinuing our Continental Connector Pipeline project and the remainder of our Seafarer Project.

Hurricanes. During 2008, we incurred damage to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Ike and Gustav. Our EBIT was unfavorably impacted by $31 million in 2008 related to these hurricanes due to gas loss from various damaged pipelines, lower volume of gas not used in operations, and repair costs that will not be recoverable from insurance due to losses not exceeding self-retention levels. (See *Liquidity and Capital Resources* for a further discussion of these hurricanes.) During 2007, we incurred lower operation and maintenance expenses to repair damage caused by Hurricanes Katrina and Rita as compared to 2006.

Equity Earnings from Citrus. In 2008, equity earnings on our Citrus investment decreased as compared to 2007 due to Citrus s favorable settlement in 2007 of approximately $8 million for litigation brought against Spectra LNG Sales (formerly Duke Energy LNG Sales, Inc.) for the wrongful termination of a gas supply contract and Citrus sale of a receivable in 2007 for approximately $3 million related to the bankruptcy of Enron North America. In addition, in 2007 we benefited by $8 million compared with 2006 due primarily to higher system usage and lower operating costs from Florida Gas Transmission Company, a pipeline owned by Citrus.

Minority Interests. During the year ended December 31, 2008 and 2007, we recorded approximately $35 million and $3 million of minority interest expense related to EPB formed in November 2007. Minority interest expense increased during 2008 due to the additional contribution of interests in CIG and SNG by El Paso to EPB.

Other Regulatory Matters. 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, while certain of our pipelines are expected to continue operating under their existing rates, other pipelines have projected upcoming rate actions with anticipated effective dates in 2009 through 2011.

In June 2008, EPNG filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposed an increase in EPNG s base tariff rates. The rates, which are subject to refund and the outcome of a hearing and technical conference, became effective on January 1, 2009. The FERC issued an order in December 2008 that generally accepted most of EPNG s proposals in the technical conference proceeding. For a further discussion of our rate case, see Item 8, Financial Statements and Supplementary Data, Note 13.

Under the terms of SNG s last rate settlement, SNG is obligated to file proposed new rates to be effective no later than October 1, 2010. SNG anticipates filing a new rate case no later than March 2009 with revised rates expected to become effective September 1, 2009.

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Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance of this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at 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. We also enter into financial derivative contracts to mitigate against significant downward price movements. Our strategy focuses on building and applying competencies in assets with repeatable programs, executing to improve capital and expense efficiency, and maximizing returns by adding assets and inventory that match our competencies and divesting assets that do not.

Our domestic natural gas and oil reserve portfolio blends lower decline rate, typically longer lived assets in our Central and Western regions, with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. Approximately 88 percent of our 2008 capital was spent on domestic projects. Internationally, our portfolio consists of producing fields along with growth projects in several areas of interest in offshore Brazil and exploration projects in Egypt. Our 2008 international capital, primarily in Brazil, constituted approximately 12 percent of our total capital program. Ongoing success of our international programs in Brazil and Egypt will require effective project management, strong partner relations and obtaining approvals from regulatory agencies, although current economic conditions may dictate the timing of our spending.

As part of our business strategy, we allocate capital between development and exploration programs, and acquisition opportunities. During 2008, we acquired interests in domestic natural gas and oil properties for approximately $61 million, including producing properties of $51 million, primarily in our Western region. The assets acquired were mainly incremental interests in properties that we already operated. Additionally, as part of our efforts to high grade our asset portfolio, during 2008, we completed the sale of certain non-core properties for net cash proceeds of approximately $637 million, primarily in our Texas Gulf Coast and Gulf of Mexico regions. These properties had estimated proved reserves of approximately 309 Bcfe and asset retirement liabilities of $109 million at December 31, 2007. These transactions, together with our 2007 acquisition of Peoples, increased the onshore U.S. weighting of our inventory of future capital projects and reduced our per-unit lease operating expenses. In January 2009, we completed the sale of two non-core natural gas producing properties in the Western and Central regions for approximately $74 million. These properties had 40 Bcfe of proved reserves and approximately 15 MMcfe/d of production at December 31, 2008.

During the fourth quarter of 2008, we along with other industry participants, experienced significant reductions in the market price of natural gas and oil. Furthermore, while service and equipment costs have declined, they have not declined commensurate with the reduction in natural gas and oil prices. These factors have challenged our economic assumptions on development and exploration as we enter into 2009. Coupled with unprecedented challenges in the credit markets, these events have resulted in us reducing capital spending in the fourth quarter of 2008 and reducing our anticipated capital program in 2009. Based on these reduced spending levels, we expect our 2009 production volumes to range between flat to down approximately 10 percent compared to 2008.

We will continue to evaluate acquisition and growth opportunities that are focused around our core competencies and areas of competitive advantage. Although the current market conditions present challenges, strategic acquisitions can support our corporate objectives, providing us greater opportunities to achieve our long term performance goals by leveraging operational expertise already possessed in key operating areas, balancing our exposure to regions, basins and commodities, achieving risk-adjusted returns competitive with those available within our existing inventory, and increasing our reserves by supplementing our current drilling inventory.

In addition to effectively executing on our strategy, our profitability and performance is impacted by (i) changes in commodity prices, (ii) industry-wide changes in the cost of drilling and oilfield services, 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 entered into derivative contracts on approximately 75 percent of our anticipated 2009 domestic natural gas production to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Year Ended December 31, 2008

Production. Our average daily production for the year was 742 MMcfe/d (which does not include 74 MMcfe/d from our share of production from our equity investment in Four Star). Below is an analysis of our 2008 production by region (MMcfe/d):

	2008	2007	2006
United States			
Central	238	227	213
Western	154	147	132
Texas Gulf Coast	225	213	187
Gulf of Mexico and south Louisiana	114	191	174
International			
Brazil	11	14	24
Total Consolidated	742	792	730
Four Star	74	70	68

Central region Our 2008 Central region production volumes continued to increase as a result of our successful Arklatex drilling programs. Our Peoples acquisition in September 2007 also contributed to the increase in 2008.

Western region Our 2008 Western region production volumes continued to increase as a result of increased production in both of our major operating areas, with the majority of the growth coming from the Rockies.

Texas Gulf Coast region Our 2008 Texas Gulf Coast region production volumes grew as a result of our Peoples and Zapata acquisitions in 2007 along with production growth coming from the South Texas Wilcox area, partially offset by the impact of hurricanes and asset sales.

Gulf of Mexico and south Louisiana region Our 2008 Gulf of Mexico and south Louisiana region production volumes decreased due to the impacts of asset sales, Hurricanes Ike and Gustav during the third quarter of 2008 and natural production declines. Hurricanes Ike and Gustav negatively impacted our production volumes by 23 MMcfe/d for the year and are continuing to have an impact on production volumes in the first quarter of 2009.

Brazil In Brazil, our 2008 production volumes decreased primarily due to natural production declines.

Four Star We increased our ownership interest in Four Star from 43 percent to 49 percent in the third quarter of 2007, which favorably impacted our share of production volumes in 2008.

2008 Drilling Results

Central. We achieved a 100 percent success rate on 324 gross wells drilled.

Western. We achieved a 100 percent success rate on 107 gross wells drilled.

Texas Gulf Coast. We achieved a 93 percent success rate on 108 gross wells drilled.

Gulf of Mexico and south Louisiana. We achieved a 77 percent success rate on 13 gross wells drilled.

Brazil. We achieved a 50 percent success rate on two gross wells drilled.

Egypt. We participated in drilling an exploratory well in the South Feiran block that was unsuccessful.

For a further discussion of our activities in Brazil and Egypt, see Part I, Item 1, Business, Exploration and Production Segment, International.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil production volumes. These costs are calculated on a per Mcfe basis and include total operating expenses less depreciation, depletion and amortization expense, ceiling test or impairment charges, transportation costs and cost of products.

During the year ended December 31, 2008, cash operating costs per unit increased to \$1.97/Mcfe as compared to \$1.88/Mcfe in 2007. The increase in 2008 is primarily due to higher production taxes resulting from higher natural gas and oil revenues and the impact of lower production volumes, partially offset by lower lease operating expenses and lower general and administrative expenses. Lease operating expenses decreased in 2008 primarily due to the divestiture of higher cost properties in the Gulf of Mexico and south Louisiana region. General and administrative expenses decreased in 2008 primarily due to the reversal of an accrual as a result of a favorable ruling on a legal matter. During 2008, the legal accrual reversal had a \$0.07/Mcfe positive impact, while lost volumes and incremental repair costs as a result of the hurricanes had an \$0.08/Mcfe adverse effect on cash operating costs.

Reserve Replacement Ratio/Reserve Replacement Costs. We calculate two primary metrics, (i) a reserve replacement ratio and (ii) reserve replacement costs, 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 reserve replacement costs 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 lower costs than our competition. We calculate these metrics as follows:

Reserve replacement ratio	Sum of reserve additions[1]
	Actual production for the corresponding period
Reserve replacement costs/Mcfe	Total oil and gas capital costs[2]
	Sum of reserve additions [1]

(1) Reserve additions include proved reserves and reflect reserve revisions for prices and performance, 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. We have presented these metrics separately, both including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of our drilling program exclusive of economic factors (such as price) outside of our control. All 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.

The reserve replacement ratio and reserve replacement costs 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, 2008, proved developed reserves represent approximately 74 percent of our 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.

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The table below shows our reserve replacement costs and reserve replacement ratio for our domestic and worldwide operations, including and excluding the effect of price revisions on reserves for each of the years ended December 31:

	Including Price Revisions			Excluding Price Revisions		
	2008	2007 ($/Mcfe)	2006	2008	2007 ($/Mcfe)	2006
Domestic						
Reserve replacement costs, including acquisitions	$ 6.68	$3.26	$3.92	$2.87	$3.46	$3.27
Reserve replacement costs, excluding acquisitions	7.01	3.22	3.94	2.87	3.65	3.29
Worldwide						
Reserve replacement costs, including acquisitions	$36.00	$3.55	$4.17	$3.25	$3.77	$3.50
Reserve replacement costs, excluding acquisitions	56.05	3.79	4.19	3.26	4.29	3.51
		(% of Production)			(% of Production)	
Domestic						
Reserve replacement ratio, including acquisitions	84%	255%	109%	195%	240%	130%
Reserve replacement ratio, excluding acquisitions	77%	129%	108%	188%	114%	129%
Worldwide						
Reserve replacement ratio, including acquisitions	17%	252%	108%	192%	237%	128%
Reserve replacement ratio, excluding acquisitions	11%	129%	107%	186%	114%	127%

We typically cite reserve replacement costs in the context of a multi-year trend, in recognition of its limitation as a single year measure, and also to demonstrate consistency and stability, which are essential to our business model. The table below shows our reserve replacement costs for our domestic and worldwide operations for the three years ended December 31, 2008.

	Including Price Revisions	Excluding Price Revisions
	Three Years Ending December 31, 2008 ($/Mcfe)	
Domestic		
Reserve replacement costs, including acquisitions	$ 4.03	$ 3.22
Reserve replacement costs, excluding acquisitions	4.37	3.21
Worldwide		
Reserve replacement costs, including acquisitions	$ 5.16	$ 3.54
Reserve replacement costs, excluding acquisitions	6.20	3.62

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

	2008	2007	2006
		(in millions)	
Total oil and gas capital costs[1]	$ 1,699	$ 2,589	$ 1,193
Less: acquisition capital	(51)	(1,178)	(4)
Capital expenditures, excluding acquisitions	$ 1,648	$ 1,411	$ 1,189

(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 2009

For 2009, we anticipate continued volatility in the commodity markets and the general economic climate. We will exercise flexibility in allocating capital in response to changing conditions. As a result, our estimated capital spending and production volumes will have wider ranges than in previous years.

We expect the following on a worldwide basis:

- Capital expenditures, excluding acquisitions, of $0.9 billion to $1.3 billion. Of this total, we expect to spend $0.7 billion to $1.0 billion on our domestic program and approximately $250 million in Brazil and Egypt. Brazil capital includes the anticipated costs to complete development of our Camarupim project in 2009.

- Average daily production volumes for the year of approximately 663 MMcfe/d to 747 MMcfe/d, which does not include approximately 62 MMcfe/d to 68 MMcfe/d from our equity investment in Four Star. Production volumes from our Brazil operations are expected to increase from an average of about 11 MMcfe/d in 2008 to between 45 MMcfe/d and 55 MMcfe/d in 2009, with production volumes from the Camarupim Field expected to commence in the second quarter of 2009.

- Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $2.05/Mcfe to $2.35/Mcfe for the year; and

- Depreciation, depletion and amortization rate of between $2.30/Mcfe and $2.50/Mcfe.

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 based on the goals of the overall company. During the fourth quarter of 2008, we discontinued hedge accounting for all of our commodity-based derivative contracts. Prior to the fourth quarter of 2008, we had commodity based derivative contracts that were treated as accounting hedges and others that were not. As a result of the decision to discontinue hedge accounting, we will reflect changes in the fair value of all of our commodity-based derivative instruments in earnings each period. For a discussion of the impact this will have on our results of operations, see Operating Results and Variance Analysis below.

The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of December 31, 2008. For a further discussion related to El Paso s production-related price risk management activities, see Liquidity and Capital Resources.

	Fixed Price Swaps(1)		**Floors(1)**		**Ceilings(1)**		**Basis Swaps(1)(2)**					
							Texas Gulf Coast		**Western-Raton**		**Rockies**	
		Average		**Average**		**Average**						
	Volumes	**Price**	**Volumes**	**Price**	**Volumes**	**Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**
Natural Gas												
2009	8	$ 7.33	168	$9.10	143	$15.41	40	$ (0.33)	25	$ (0.95)	13	$ (2.01)
2010	5	$ 3.70										
2011-2012	7	$ 3.88										
Oil												
2009	3,431	$109.93										

(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 limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational price differences.

During the first two months of 2009, we settled all of our remaining 2009 fixed price oil swaps for approximately $186 million in cash while entering into new contracts for approximately 1,500 MBbls of fixed price oil swaps on our anticipated 2009 oil production at an average price of $45.00 per barrel. We also entered into 22 TBtu of natural gas floor contracts at an average price of $7.00 per MMBtu as well as 23 TBtu of natural gas basis swap contracts at an average price of $0.60 per MMBtu related to our anticipated 2009 natural gas production. Related to our anticipated 2010 natural gas production, we paid approximately $35 million in premiums to add 22 TBtu of $7.00 per MMBtu floor contracts, and we entered into 20 TBtu fixed price swap contracts at an average price of $7.28 per MMBtu and 57 TBtu basis swap contracts at an average price of $0.72 per MMBtu.

Operating Results and Variance Analysis

The information below provides the financial results and an analysis of significant variances in these results during the periods ended December 31:

	2008	2007 (In millions)	2006
Operating Revenues:			
Natural gas	$ 1,885	$ 1,764	$ 1,406
Oil, condensate and NGL	507	494	430
Changes in fair value of derivative contracts not designated as accounting hedges	305	7	(40)
Other	65	35	58
Total operating revenues	2,762	2,300	1,854
Operating Expenses:			
Cost of products	(38)	(20)	(29)
Transportation costs	(79)	(72)	(58)
Production costs	(363)	(344)	(331)
Depreciation, depletion and amortization	(799)	(780)	(645)
General and administrative expenses	(160)	(185)	(156)
Ceiling test charges	(2,669)		
Other	(12)	(13)	(10)
Total operating expenses	(4,120)	(1,414)	(1,229)
Operating income	(1,358)	886	625
Other income (expense)[1]	(90)	23	15
EBIT	$ (1,448)	$ 909	$ 640

(1) Other income includes equity earnings from our investment in Four Star, which in 2008 included a $125 million impairment charge related to our ownership interest in Four

Star.

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	2008	Percent Variance	2007	Percent Variance	2006
Consolidated volumes, prices and costs per unit:					
Natural gas					
Volumes (MMcf)	232,703	(4)%	242,316	10%	220,402
Average realized prices including hedges($/Mcf)	$ 8.10	11%	$ 7.28	14%	$ 6.38
Average realized prices excluding hedges ($/Mcf)	$ 8.43	29%	$ 6.53	(2)%	$ 6.64
Average transportation costs ($/Mcf)	$ 0.31	15%	$ 0.27	17%	$ 0.23
Oil, condensate and NGL					
Volumes (MBbls)	6,495	(17)%	7,821	2%	7,686
Average realized prices including hedges ($/Bbl)	$ 78.10	24%	$ 63.11	13%	$ 55.90
Average realized prices excluding hedges ($/Bbl)	$ 83.21	31%	$ 63.71	13%	$ 56.21
Average transportation costs ($/Bbl)	$ 0.96	19%	$ 0.81	(1)%	$ 0.82
Total equivalent volumes					
MMcfe	271,673	(6)%	289,242	9%	266,518
MMcfe/d	742	(6)%	792	8%	730
Production costs and other cash operating costs ($/Mcfe)					
Average lease operating expenses	$ 0.90	2%	$ 0.88	(7)%	$ 0.95
Average production taxes[1]	0.44	42%	0.31	7%	0.29
Total production costs	$ 1.34	13%	$ 1.19	(4)%	$ 1.24
Average general and administrative expenses	$ 0.59	(8)%	$ 0.64	8%	$ 0.59
Average taxes, other than production and income taxes	$ 0.04	(20)%	$ 0.05	67%	$ 0.03
Total cash operating costs	$ 1.97	5%	$ 1.88	1%	$ 1.86
Depreciation, depletion and amortization ($/Mcfe)	$ 2.94	9%	$ 2.70	12%	$ 2.42
Unconsolidated affiliate volumes (Four Star)					
Natural gas (MMcf)	20,576		19,380		18,140
Oil, condensate and NGL (MBbls)	1,054		1,015		1,087
Total equivalent volumes					
MMcfe	26,899		25,470		24,663
MMcfe/d	74		70		68

(1) Production taxes include ad

valorem and
severance taxes.

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Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Our EBIT for 2008 decreased $2,357 million as compared to 2007. The table below shows the significant variances in our financial results in 2008 as compared to 2007:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenues				
Higher realized prices in 2008	$ 441	$	$	$ 441
Impact of accounting hedges	(257)			(257)
Lower volumes in 2008	(63)			(63)
Oil, Condensate and NGL Revenues				
Higher realized prices in 2008	127			127
Impact of accounting hedges	(29)			(29)
Lower volumes in 2008	(85)			(85)
Other Revenue				
Change in fair value of derivatives not designated as accounting hedges	298			298
Other	30			30
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2008		(64)		(64)
Lower production volumes in 2008		45		45
Production Costs				
Lower lease operating expenses in 2008		10		10
Higher production taxes in 2008		(29)		(29)
General and Administrative Expenses		25		25
Ceiling Test Charges		(2,669)		(2,669)
Other				
Earnings from investment in Four Star			(104)	(104)
Other		(24)	(9)	(33)
Total Variances	$ 462	$ (2,706)	$ (113)	$ (2,357)

Natural gas, oil, condensate and NGL revenues. During 2008, revenues increased as compared with 2007 due primarily to higher commodity prices, including the effects of derivatives we designated as accounting hedges. Losses recognized on hedging settlements totaled $109 million for 2008 as compared to gains of $177 million in 2007, which resulted from higher commodity prices in 2008 versus 2007 relative to our derivative contract prices for each of those years. These settlements include premiums paid on our derivative option contracts. During the year ended December 31, 2008, we also benefited from an increase in production volumes in our Central, Western and Texas Gulf Coast regions compared to 2007, primarily as a result of a successful drilling programs and our Peoples acquisition in the third quarter of 2007. Our Gulf of Mexico and south Louisiana region production volumes decreased in 2008 versus 2007 primarily due to asset sales, production shut in as a result of Hurricanes Ike and Gustav and natural production declines.

Other revenue. During 2008, we recognized mark-to-market gains of $305 million compared to gains of $7 million during 2007 related to changes in the fair value of derivatives not designated as accounting hedges. During the year ended December 31, 2008, we received $18 million on contracts that were settled during the period, compared to payments of $31 million on contracts that were settled during 2007. During the fourth quarter of 2008,we discontinued the use of hedge accounting. As a result of this decision, the value of the derivatives on the date we discontinued hedge accounting will be amortized into revenue in the month the contracts are settled. The amount that will be recognized as revenue in 2009 related to these derivatives is approximately $409 million. Subsequent changes in the fair value of these derivatives will also be recognized in revenue when they occur.

Depreciation, depletion and amortization expense. During 2008, our depletion rate increased as compared to the same period in 2007 as a result of the Peoples and Zapata County, Texas acquisitions in 2007 and higher finding and development costs. Our depreciation, depletion and amortization rate includes $0.05 per Mcfe in 2008, compared to $0.07 per Mcfe in 2007, related to accretion expense on asset retirement obligations. As a result of the ceiling test charges discussed below, our depreciation, depletion and amortization rate will decrease in 2009 from the current rate.

Production costs. Our production costs increased during 2008 as compared to the same period in 2007 primarily due to higher production taxes which increased due to higher natural gas and oil revenues. The increase in production taxes was partially offset by a reduction in lease operating expenses for the year ended December 31, 2008, primarily as a result of the impact of divested properties in the Gulf of Mexico and south Louisiana region.

General and administrative expenses. Our general and administrative expenses decreased during 2008 as compared to the same periods in 2007 primarily due to the reversal of a $20 million accrual as a result of a favorable ruling on a legal matter.

Ceiling test charges. In the fourth quarter of 2008, we recorded non-cash full cost ceiling test charges of $2.7 billion. Capitalized costs exceeded the ceiling limit by $2.2 billion for our domestic full cost pool and $0.5 billion for our Brazilian full cost pool. The calculation of these charges was based on the December 31, 2008 spot natural gas price of $5.71 per MMBtu and oil price of $44.60 per barrel. In calculating our ceiling test charges, we are required to hold prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. During the first two months of 2009, natural gas and oil prices have declined from the levels at December 31, 2008. We may be required to record additional ceiling test charges in the future unless commodity prices significantly increase or oilfield service costs significantly decrease from their current levels.

Historically, we have included derivatives that are designated as accounting hedges in the determination of our future net revenues for purposes of calculating our ceiling tests. During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivative contracts related to our hedged natural gas and oil production volumes. We estimate that had we chosen not to de-designate these hedges, our ceiling test charges as of December 31, 2008 would have been lower by approximately $400 million.

Other. Our equity earnings from Four Star for 2008 decreased as compared to 2007 due primarily to an impairment of the carrying value of our investment of $125 million based on a decline in the fair value of this investment as a result of lower forecasted commodity prices.

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Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Our EBIT for 2007 increased $269 million as compared to 2006. The table below shows the significant variances in our financial results in 2007 as compared to 2006:

	Variance Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenues				
Lower realized prices in 2007	$ (26)	$	$	$ (26)
Impact of accounting hedges	239			239
Higher volumes in 2007	145			145
Oil, Condensate and NGL Revenues				
Higher realized prices in 2007	59			59
Impact of accounting hedges	(4)			(4)
Higher volumes in 2007	7			7
Other Revenue				
Change in fair value of derivatives not designated as accounting hedges	47			47
Other	(21)			(21)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2007		(82)		(82)
Higher production volumes in 2007		(52)		(52)
Production Costs				
Higher lease operating expenses in 2007		(1)		(1)
Higher production taxes in 2007		(12)		(12)
General and Administrative Expenses		(29)		(29)
Other				
Earnings from investment in Four Star			2	2
Other		(9)	6	(3)
Total Variances	$ 446	$ (185)	$ 8	$ 269

Natural gas, oil, condensate and NGL revenues. During 2007, revenues increased compared with 2006 due to higher realized natural gas and oil prices, including the effects of derivatives we account for as hedges. Realized gains on accounting hedges were $177 million during 2007, as compared to realized losses of $58 million in 2006. During 2007, we also benefited from an increase in production volumes in all domestic regions over 2006.

Other revenue. During 2007, we recognized mark-to-market gains of $7 million compared to losses of $40 million in 2006 related to changes in the fair value of derivatives not designated as accounting hedges. During the year ended December 31, 2007 and 2006, we made payments of $31 million and $16 million on contracts that were settled during the periods.

Depreciation, depletion and amortization expense. During 2007, our depletion rate increased as compared to the same period in 2006 as a result of the Peoples and Zapata County, Texas property acquisitions and higher finding and development costs. Our depreciation, depletion and amortization rate includes $0.07 per Mcfe for both years 2007 and 2006, related to accretion expense on asset retirement obligations.

Production costs. Our production taxes increased during 2007 as compared to 2006 primarily due to higher natural gas and oil revenues and lower severance tax credits in 2007.

General and administrative expenses. Our general and administrative expenses increased during 2007 as compared to 2006 primarily due to higher marketing and other costs previously included in our Marketing segment and higher corporate overhead allocations.

Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s natural gas and oil production, manage El Paso s overall price risk, and manage our remaining legacy contracts that were entered into prior to the deterioration of the energy trading environment in 2002. To the extent it is economical and prudent, we will continue to seek opportunities to reduce the impact of remaining legacy contracts on our future operating results through contract liquidations. As of December 31, 2008, all of our production-related natural gas and oil derivative contracts held by the Marketing segment had terminated or expired. Accordingly, our Exploration and Production segment now holds all of El Paso s remaining production-related derivative contracts.

The primary remaining exposure to our operating results relates to changes in the fair value of our legacy PJM power contracts primarily related to changes in power prices at locations within the PJM region. Over the past few years, we have entered into several transactions to reduce the volatility of our legacy contracts and their impact on our operating results. In addition to the PJM power contracts, our legacy contracts include natural gas derivative contracts which are marked-to-market in our operating results as well as transportation-related natural gas and long-term natural gas supply contracts which are accrual-based contracts that impact our revenues as delivery or service under the contracts occurs. All of our remaining contracts are subject to counterparty credit and non-performance risk while each of our mark-to-market contracts is also subject to interest rate exposure. For a further discussion of our remaining contracts, see below and in Item 1, Business, Marketing Segment.

Operating Results

Overview. Over the past three years, our operating results and year-to-year comparability have been impacted by significant commodity and other market fluctuations and changes in the composition of our portfolio (and related effort to manage our portfolio) based on actions taken to reduce exposure and exit our legacy trading activities. The tables below and discussions that follow provide further information about 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:

	2008	2007	2006
		(In millions)	
Revenue by Significant Contract Type:			
Production-Related Natural Gas and Oil Derivative Contracts:			
Changes in fair value of options and swaps	$ (50)	$ (89)	$ 269
Contracts Related to Legacy Trading Operations:			
Changes in fair value of power contracts	(46)	(77)	71
Natural gas transportation-related contracts:			
Demand charges	(35)	(98)	(125)
Settlements, net of termination payments	41	76	(110)
Changes in fair value of other natural gas derivative contracts	7	(31)	(163)
Total revenues	(83)	(219)	(58)
Operating expenses	(20)	(15)	(33)
Operating loss	(103)	(234)	(91)
Other income, net	(1)	32	20
EBIT	$ (104)	$ (202)	$ (71)

Our 2008 and 2007 results were primarily driven by mark-to-market losses on our production-related natural gas and oil derivative contracts and changes in the fair market value of our PJM power contracts. In 2008, we also recognized $19 million of revenue, reflected in changes in fair value of other natural gas derivative contracts above, related to bankruptcy settlements. In 2007, also impacting our results were mark-to-market losses on our other legacy natural gas derivative contracts, $23 million of other income recognized upon the sale of our investment in the NYMEX and $28 million of EBIT ($23 million of revenues and $5 million of other income) related to the settlement of outstanding California power price disputes.

Our 2006 results were primarily driven by losses from the divestiture of a significant portion of our natural gas portfolio, a $188 million termination payment related to our Alliance transportation capacity obligations, and changes in fair value of our other natural gas derivative contracts including approximately $133 million related to our MCV supply agreement. These losses were partially offset by significant mark-to-market gains in 2006 on our production-related natural gas and oil derivative contracts.

Production-related Natural Gas and Oil Derivative Contracts. Prior to their expiration or termination in 2008, we held production-related natural gas and oil derivative contracts in addition to those derivative contracts entered into by our Exploration and Production segment. During 2008, our remaining oil option contracts expired and we terminated our remaining 17 TBtu of 2009 natural gas option contracts with a floor price of $6.00 per MMBtu and a ceiling price of $8.75 per MMBtu by paying approximately $57 million.

Changes in the fair value of these contracts were marked-to-market in our financial results and impacted by the volatility in commodity prices from period-to-period. During 2008 and 2007, increases in forward commodity prices reduced the fair value of our option contracts resulting in a loss on these contracts. During 2006, decreases in forward commodity prices increased the fair value of our derivative contracts resulting in a gain. During 2008, we paid approximately $40 million on contracts settled during that period, exclusive of the termination payment described above. We received approximately $45 million and $59 million in 2007 and 2006 on contracts that settled during those periods.

Contracts Related to Legacy Trading Operations

Power contracts. Our primary remaining exposure in our power portfolio consists of changes in locational power price differences in the PJM region and changes in interest rates. Prior to agreements entered into from 2006 through 2008, we were also exposed to changes in installed capacity prices and commodity prices. Power prices in the PJM region are highly volatile due to changes in fuel prices and transmission congestion at certain locations in the region, and future changes in locational prices could continue to significantly impact the fair value of our power contracts.

Changes in the fair value of our PJM contracts resulted in mark-to-market losses of approximately $46 million in 2008 and $100 million in 2007 and mark-to-market gains of approximately $71 million in 2006. For the year ended December 31, 2008, the decrease in fair value of these contracts was primarily related to significant reductions in interest rates used to estimate the contracts fair value. Also impacting our results in 2008 was a capacity purchase agreement executed with a counterparty that, when combined with capacity prices established in auctions held by the PJM Independent System Operator for periods prior to June 2011, economically hedged our exposure to supplying capacity in the PJM region for the remainder of the contract term. Prior to this time, we recorded significant losses in 2007 based on installed capacity price changes and gains in 2006 primarily related to changing locational price differences in the PJM region. For the years ended December 31, 2008, 2007 and 2006, total cash settlements paid on our power contracts were approximately $66 million, $50 million and $41 million.

Natural gas transportation-related contracts. As of December 31, 2008, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. 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. As of December 31, 2008, our contracts require us to pay demand charges of $41 million in 2009 and an average of $22 million between 2010 and 2013. The following table is a summary of demand charges (in millions) and percentage of recovery of these charges for each of the three years ended December 31:

	2008	2007	2006
Alliance[(1)]:			
Demand charges	$	$ 56	$64
Recovery		48%	59%
Other:			
Demand charges	$ 35	$ 42	$61
Recovery	100%	100%	68%

(1)

Effective November 2007, our obligation under the Alliance capacity agreement was transferred to a third party. Excluded from amounts recovered is the $188 million we paid in 2006 in conjunction with the sale of this contract.

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Other natural gas derivative contracts. We also have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices; however, we have substantially offset all of the fixed price exposure in these contracts. In 2006, in conjunction with the sale of the MCV facility in our Power segment, we recorded cumulative mark-to-market losses of approximately $133 million on our MCV gas supply contract associated with this facility which had not been previously recognized due to our affiliated ownership interest. Additionally, we recognized a $49 million gain in 2006 associated with the assignment of certain natural gas derivative contracts to supply natural gas in the southeastern U.S.

Power Segment

Overview. As of December 31, 2008, our remaining investment, guarantees and letters of credit related to projects in our Power segment totaled approximately $396 million, which consisted of approximately $380 million in equity investments and notes receivable and approximately $16 million in financial guarantees and letters of credit for the following projects:

Area		**Amount (In millions)**
Brazil		
Porto Velho	$	178
Manaus & Rio Negro		42
Pipeline projects		158
Asia		18
Total	$	396

During 2008, we sold our remaining Central American power investment, an Asian power investment and transferred the ownership of our Manaus and Rio Negro power plants in Brazil to the plants power purchaser. While we no longer own the Manaus and Rio Negro power plants, we still have exposure relating to outstanding receivables due from the power purchaser. In February 2009, we completed the sale of our investment in Porto Velho. See Part II, Item 8, Financial Statements and Supplementary Data, Note 18, for a further discussion of the sale of this investment.

The sale of our investment in the Argentina to Chile pipeline is also expected to be completed in the first half of 2009, which will reduce our exposure to pipeline projects to $131 million. Until the sale of our remaining international investments is completed, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in impairments of our remaining investments.

A discussion of these events and other factors impacting our results in this segment for the three years ended December 31 are listed below:

		2008		**2007 (In millions)**		**2006**
EBIT by Area:						
Brazil						
Impairments	$		$	(72)	$	
Other EBIT from operations		7		51		64
Other International Power						
Impairments, net of gains (losses) on sales		6		(1)		(12)
Other EBIT from operations		(2)		(1)		(1)
Gain on sale of available-for-sale investment [1]						47
Other[2]		(10)		(14)		(16)

EBIT	$ 1	$ (37)	$ 82

(1) Relates to the disposition of our remaining shares of International Commodity Exchange in 2006.

(2) Consists of indirect expenses and general and administrative costs.

Brazil. In 2008, our remaining Brazilian operations (primarily our interests in the Bolivia-to-Brazil and Argentina-to-Chile pipelines) generated EBIT of $7 million, net of a $17 million foreign exchange loss related to our Brazil reais-denominated receivables we have related to our formerly owned Manaus and Rio Negro projects. We are also in the process of resolving several outstanding claims related to the Manaus and Rio Negro projects that are denominated in Brazilian reais. The ultimate resolution of these matters could impact our results in the future.

In the first half of 2007, we generated EBIT from operations of $30 million from our Porto Velho project and $9 million from our Manaus and Rio Negro project. However, in the second half of 2007, we recorded impairments of $57 million on Porto Velho and $15 million on the Manaus and Rio Negro project based on adverse developments at these projects. Beginning in the second half of 2007, we ceased recognizing earnings from our Porto Velho project based on our inability to realize those earnings through the expected sales price of the investment. In 2007, our other Brazilian operations generated EBIT of $12 million. In 2006, EBIT was $41 million for Porto Velho, $17 million for Manaus and Rio Negro and $6 million for our other Brazilian operations.

For a further discussion of matters that have impacted or could impact our remaining Brazil investments, see Item 8, Financial Statements, Note 18.

International Power. Our 2008 earnings relate primarily to gains recognized on the sale of investments in Central America and Asia. Our results in each period were impacted by our decision to not recognize earnings from assets we planned to sell based on our inability to realize those earnings through their expected selling price. We did not recognize earnings of approximately $3 million, $10 million and $26 million for the years ended December 31, 2008, 2007 and 2006.

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 activities for each of the three years ended December 31:

	2008	2007	2006
		(In millions)	
Change in litigation, insurance and other reserves	$ 84	$ 23	$ (71)
Early extinguishment/exchange of debt		(291)	(26)
Foreign currency fluctuations on Euro-denominated debt		(8)	(20)
Gain on the sale of assets	35		
Other	5	(7)	29
Total EBIT	$ 124	$ (283)	$ (88)

Litigation, Insurance, and Other Reserves. During 2008, we recorded a net favorable adjustment related to certain legacy litigation matters, including developments in our Case Corporation indemnification dispute (See Item 8, Financial Statements and Supplementary Data, Note 13). Partially offsetting this adjustment were mark-to-market losses for an indemnification in conjunction with the sale of a legacy ammonia facility. The mark-to-market losses were based on significant changes in ammonia prices during 2008. It is uncertain whether the current ammonia prices will continue in the long-term based on the illiquid nature of the forward market for ammonia. Further changes in ammonia prices may continue to impact our liability, which could impact our results in the future.

During 2007, we recorded a gain of approximately $77 million on the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business.

We have a number of pending litigation matters and reserves related to our historical business operations that also affect our corporate results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters impacted our results in 2008, 2007 and 2006 and may impact our future results.

Extinguishment of Debt. During 2007, we incurred losses of $291 million in conjunction with repurchasing or refinancing more than $5 billion of debt. This amount included $86 million related to repurchasing EPEP s $1.2 billion notes. For further information on our debt, see Item 8, Financial Statements, Note 12.

Interest and Debt Expense

Our interest and debt expense of approximately $0.9 billion, $1.0 billion and $1.2 billion during the years ended December 31, 2008, 2007 and 2006 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.

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Income Taxes

	Years Ended December 31,		
	2008	2007	2006
	(In millions)		
Income taxes from continuing operations	$(245)	$222	$(9)
Effective tax rate	23%	34%	(2)%

In 2008, our overall effective tax rate on continuing operations differed from the statutory rate due primarily to: (i) a Brazilian ceiling test charge in our exploration and production operations that did not have a corresponding U.S. or Brazilian tax benefit and (ii) the establishment of a valuation allowance against deferred tax assets (associated with Brazilian net operating losses) based on uncertainties about our ability to realize these assets. In 2007, our overall effective tax rate on continuing operations was impacted by earnings from unconsolidated affiliates where we anticipate receiving dividends that qualify for the dividend received deduction. In 2006, we recorded $159 million of tax benefits based primarily on the conclusion of IRS audits of The Coastal Corporation s 1998-2000 tax years and El Paso s 2001 and 2002 tax years which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. For a discussion of these and other items affecting our effective tax rates in each year and other tax matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 5.

Discontinued Operations

Our discontinued operations in 2007 and 2006 primarily include our ANR pipeline and related assets. For the years ended December 31, 2007 and 2006, our discontinued operations generated income of $674 million and losses of $56 million. In 2007, we recorded a gain on the sale of ANR and related operations of $648 million, net of income taxes of $354 million. In 2006, the losses were primarily a result of recording approximately $188 million of deferred taxes upon agreeing to sell the stock of ANR and related assets. 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. All of these items are further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 2.

Commitments and Contingencies

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

Liquidity and Capital Resources

Over the past several years, our focus has been on expanding our core pipeline and exploration and production businesses to provide for long-term growth and value. During this period, we also strengthened our balance sheet primarily through significant debt reductions. Our primary sources of cash are cash flow from operations and amounts available to us under our revolving credit facilities. As conditions warrant, we may also generate funds through capital market activities and asset sales. Our primary uses of cash are funding the capital expenditure programs of our pipeline and exploration and production operations, meeting operating needs and repaying debt when due or repurchasing debt when conditions warrant.

In 2008, we generated significant positive operating cash flows from both our core pipeline and production operations which we expect to continue in 2009. However, during the second half of 2008, the global financial markets experienced significant volatility and instability, and in November 2008, we announced certain actions that we would take including a reduction in our capital program for 2009, partnering on certain expansion projects and selling certain non-core assets, primarily in our Exploration and Production and Power segments. Since that announcement, we have taken several steps to address our liquidity needs. Discussed below are our (i) available liquidity and liquidity outlook for 2009 as well as (ii) an overview of cash flow activities for 2008.

Available Liquidity and Liquidity Outlook for 2009. At December 31, 2008, we had approximately $1.0 billion of cash and approximately $1.2 billion of capacity available to us under our various credit facilities, exclusive of $150 million available to EPB under its revolving credit facility. Traditionally, we have pursued additional bank financings, project financings or debt capital markets transactions to supplement our available cash and credit facilities which we have used to fund the capital expenditure programs of our core businesses, meet operating needs and repay debt maturities.

Our planned cash capital expenditures in our pipeline and exploration and production operations for 2009 are as follows:

	Total (In billions)
Pipelines	
Maintenance	$ 0.4
Growth	1.3
Exploration and Production (1)	1.3
	$ 3.1

(1) For 2009, our planned cash capital, excluding acquisitions, may range from $0.9 billion to $1.3 billion.

In November 2008, we announced that our projected liquidity needs, which include our 2009 capital program and debt maturities in May 2009, required us to raise $500 million to $800 million of capital in the second half of 2009. Since that time we have successfully generated additional liquidity of approximately $1.9 billion primarily through several debt offerings, new credit facilities, and completing certain non-core asset sales. Since November 2008, we completed three separate capital markets transactions totaling $1.2 billion which included (i) $500 million of senior unsecured El Paso notes in December 2008, (ii) $250 million of senior unsecured TGP notes in January 2009, and (iii) $500 million of additional El Paso senior unsecured notes in February 2009. We also obtained a 364-day $300 million secured revolving credit facility collateralized by certain proved oil and gas reserves of a production subsidiary, entered into an additional $100 million letter of credit facility and issued $135 million of debt through our subsidiary that owns our Elba Island LNG facility. With these transactions, we increased our available liquidity to approximately $3.3 billion as of February 27, 2009. In 2009, we have sold or are evaluating the sale of approximately $0.4 billion of non-core assets that primarily consist of exploration and production properties and international power assets, of which $0.2 billion have already been completed.

Prior to November 2008, we had also completed several other financing transactions that increased our cash on hand or enhanced our available liquidity including, (i) securing approximately $870 million of project financing related to our equity investment in our Gulf LNG Clean Energy project, (ii) entering into new agreements that provide us with approximately $450 million in additional letters of credit to support our obligations to purchase pipe associated with constructing our Ruby pipeline project, (iii) issuing $600 million of unsecured El Paso notes in June 2008, and (iv) contributing an additional 30% interest in CIG and 15% interest in SNG to EPB which provided cash for us of $254 million. We currently have a 72% limited partner interest and a 2% general partner interest in EPB.

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We believe our actions taken in 2008 and over the last several months provide sufficient liquidity to carry us into 2010, meeting our operating needs, repaying our $1.1 billion of 2009 debt maturities and funding our 2009 capital program. Accordingly, we do not expect to have to further access the capital markets in 2009, regardless of whether we are successful in obtaining equity partners on any of our capital projects. However, we will continue to be opportunistic in building liquidity where prudent to meet our long-term capital needs. To the extent the financial markets are restricted, there is a further decline in commodity prices from current levels, or any of our announced actions are not sufficient, it is possible that additional adjustments to our plan and outlook will be required which could impact our financial and operating performance. These alternatives or adjustments to our plan could include additional reductions in our discretionary capital program, secured financing arrangements, seeking partners for one or more of our other growth projects and the sale of additional non-core assets which could impact our financial and operating performance.

Additional Factors That Could Impact Our Future Liquidity. Listed below are two additional factors that could impact our liquidity.

Price Risk Management Activities and Margining Requirements. Our Exploration and Production segment has derivative contracts that provide price protection on a portion of our anticipated natural gas and oil production. The following table shows the contracted volumes and the minimum, maximum and average cash prices that we will receive under our derivative contracts when combined with the sale of the underlying production as of December 31, 2008. For additional information on the income impacts of our derivative contracts, see our Exploration and Production segment s results discussion.

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)					
							Texas Gulf Coast		Western-Raton		Rockies	
		Average		Average		Average						
	Volumes	Price	Volumes	Price	Volumes	Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2009	8	$ 7.33	168	$9.10	143	$15.41	40	$(0.33)	25	$(0.95)	13	$(2.01)
2010	5	$ 3.70										
2011-2012	7	$ 3.88										
Oil												
2009	3,431	$109.93										

(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 limit our exposure to differences between the NYMEX gas

price and the price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational price differences.

During the first two months of 2009, we settled all of our remaining 2009 fixed price oil swaps receiving approximately $186 million in cash while entering into new contracts for approximately 1,500 MBbls of fixed price oil swaps on our anticipated 2009 oil production at an average price of $45.00 per barrel. We also entered into 22 TBtu of natural gas floor contracts at an average price of $7.00 per MMBtu as well as 23 TBtu of natural gas basis swap contracts at an average price of $0.60 per MMBtu related to our anticipated 2009 natural gas production. Related to our anticipated 2010 natural gas production, we paid approximately $35 million in premiums to add 22 TBtu of $7.00 per MMBtu floor contracts, and we entered into 20 TBtu fixed price swap contracts at an average price of $7.28/MMBtu and 57 TBtu basis swap contracts at an average price of $0.72 per MMBtu.

We currently post letters of credit for the required margin on certain of our derivative contracts. Depending on changes in commodity prices or interest rates, we could be required to post additional margin or may recover margin earlier than anticipated. Based on our derivative positions at December 31, 2008, a $0.10/MMBtu increase in the price curve of natural gas over the next several years would increase our margin requirements by approximately $2 million in the aggregate over the life of the contracts.

We are exposed to (and have adjusted the fair value of these contracts for) the risk that the counterparties to our derivative contracts may not be able to perform or post the necessary collateral with us. We have assessed this counterparty credit and non-performance risk given the recent instability in the credit markets and determined that our exposure is primarily limited to five financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

Hurricanes Ike and Gustav. During 2008, our pipeline and exploration and production facilities were damaged by Hurricanes Ike and Gustav. We assessed the damages resulting from these hurricanes and the corresponding impact on estimated costs to repair and abandon impacted facilities. Although our estimates may change in the future, we currently estimate total repair and abandonment costs of approximately $115 million in our pipelines and between $30 million to $35 million in our exploration and production business, a majority of which we also expect will be capital expenditures in 2009 and 2010. None of these amounts are recoverable from insurance due to the losses not exceeding our self-retention levels for these events.

Overview of Cash Flow Activities. During 2008, we generated positive operating cash flow from both our core pipeline and exploration and production businesses of $2.4 billion. However, earnings and cash flow in our exploration and production business were adversely impacted by the decline in commodity prices during the fourth quarter of 2008 and the effects on production volumes of the recent hurricanes. In addition, we generated approximately $0.7 billion in proceeds primarily from the sale of oil and gas properties and $1.2 billion in proceeds in conjunction with the issuance of unsecured notes. We utilized these amounts to fund maintenance and growth projects in our pipeline and exploration and production operations (including the acquisition of a 50 percent interest in the Gulf LNG Clean Energy project), to pay down or repurchase debt, and pay dividends, among other items. For the year ended December 31, 2008 and 2007, our cash flows from continuing operations are summarized as follows:

	2008	2007
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Income (loss) from continuing operations	$ (0.8)	$ 0.4
Ceiling test charges	2.7	
Other income adjustments	1.2	1.7
Change in other assets and liabilities	(0.7)	(0.3)
Total cash flow from operations	$ 2.4	$ 1.8
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.7	$ 0.1
Other	0.1	
	0.8	0.1
Continuing financing activities		
Net proceeds from the issuance of long-term debt(1)	4.6	6.6
Net proceeds from issuance of minority interest in consolidated subsidiary		0.5
Contributions from discontinued operations		3.4
	4.6	10.5
Total other cash inflows	$ 5.4	$ 10.6
Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 2.8	$ 2.5

Cash paid for acquisitions	0.4	1.2
	3.2	3.7
Continuing financing activities		
Payments to retire long-term debt and other financing obligations[1]	3.7	8.9
Dividends, repurchase of El Paso common stock and other	0.2	0.1
	3.9	9.0
Total cash outflows	$ 7.1	$ 12.7
Net change in cash	$ 0.7	$ (0.3)

(1) Includes activity under our revolving credit facilities.

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Off-Balance Sheet Arrangements

We enter into a variety of financing arrangements and contractual obligations, some of which are referred to as off-balance sheet arrangements. These include guarantees, letters of credit and other interests in variable interest entities.

Guarantees and Indemnifications

We are involved in various joint ventures and other ownership arrangements that sometimes require 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, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $797 million, which primarily relates to indemnification arrangements associated with the sale of ANR, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 12. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of December 31, 2008, we have recorded obligations of $62 million related to our indemnification arrangements. This liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification.

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, 2008, we had outstanding letters of credit of approximately $1.6 billion, including $0.8 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, 2008, the only significant variable interest entity that we do not consolidate is Porto Velho, since we are not the primary beneficiary of the variable interest entity s operations. For additional information regarding our interests in Porto Velho, see Part II, Item 8 Financial Statements and Supplementary Data, Note 18, Investments in, Earnings from and Transactions with Unconsolidated Affiliates.

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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, 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, 2008, for each of the periods presented:

	Due in Less than 1 Year	Due in 1 to 3 Years	Due in 3 to 5 Years	Thereafter	Total
			(In millions)		
Long-term financing obligations:					
Principal	$ 1,090	$ 938	$ 3,142	$ 8,837	$ 14,007
Interest	915	1,708	1,479	7,540	11,642
Liabilities from commodity-based derivative contracts	245	430	199	122	996
Other contractual liabilities	63	76	30	43	212
Operating leases	15	18	13	24	70
Other contractual commitments and purchase obligations:					
Transportation and storage	39	67	42	147	295
Other	1,141	986	14	9	2,150
Total contractual obligations	$ 3,508	$ 4,223	$ 4,919	$ 16,722	$ 29,372

Long Term Financing Obligations (Principal and Interest). Debt obligations included represent stated maturities unless otherwise puttable to us prior to their stated maturity date. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. For a further discussion of our debt obligations, see Item 8, Financial Statements and Supplementary Data, Note 12.

Liabilities from Commodity-Based Derivative Contracts. These amounts only include the fair value of our price risk management liabilities. The fair value of our commodity-based price risk management assets of $971 million as of December 31, 2008 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, because these expected contributions are not contractually required. For further information on our expected contributions to our pension and post retirement benefit plans, see Part II, Item 8, Financial Statements and Supplementary Data, Note 14. We have also excluded from these amounts liabilities for unrecognized tax benefits of $173 million as of December 31, 2008, since we cannot reasonably estimate the time frame over which those amounts may be resolved.

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.

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Other Commitments. Included in these amounts are commitments for purchasing pipe and related assets in our pipeline operations, 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 these liabilities are not contractually fixed as to timing and amount.

Commodity-Based Derivative Contracts. We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. Our commodity-based derivative contracts are not currently designated as accounting hedges and include options, swaps and other natural gas, oil and power purchase and supply contracts that are not traded on active exchanges. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of December 31, 2008:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Total Fair Value
			(In millions)		
Assets	$ 782	148	25	16	$ 971
Liabilities	(245)	(430)	(199)	(122)	(996)
Total commodity-based derivatives	$ 537	(282)	(174)	(106)	$ (25)

The following is a reconciliation of our commodity-based derivatives for the years ended December 31, 2008 and 2007:

	Derivatives Designated as Accounting Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at December 31, 2006	$ 61	$ (456)	$ (395)
Fair value of contract settlements during the period(1)	(109)	(224)	(333)
Change in fair value of contracts	4	(211)	(207)
Assignment of contracts		18	18
Net option premiums paid	21	4	25
Net change in contracts outstanding during the period	(84)	(413)	(497)
Fair value of contracts outstanding at December 31, 2007	(23)	(869)	(892)
Fair value of contracts settled	88	257	345
Changes in fair value of contracts	309	197	506
Reclassification of de-designated hedges	(395)	395	
Net option premiums paid (received)	21	(5)	16

Net change in contracts outstanding during the period	23	844	867
Fair value of contracts outstanding at December 31, 2008	$	$ (25)	$ (25)

(1) In 2007, we settled derivative assets of approximately $381 million by applying the related cash margin we held against amounts due to us under those contracts.

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.

Reclassifications of De-designated Hedges. During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivative contracts related to our hedged natural gas and oil production volumes.

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 and those that could significantly influence our financial results based on changes in those judgments. 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 NGL which geological and engineering data demonstrate, with reasonable certainty, will 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 which is 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, conducted an audit of the estimates of a significant portion of our proved reserves. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising approximately 80 percent of our total worldwide present value of future cash flows on a pretax basis. The specific fields included in Ryder Scott s audit represented the largest fields based on value.

As of December 31, 2008, of our total proved reserves, 26 percent were undeveloped and 13 percent were developed, but non-producing. The data for a given field may 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 and any ceiling test charges 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, asset retirement costs and capitalized interest. Capitalized costs are maintained in full cost pools by geographic area, regardless of whether reserves are actually discovered. We record depletion expense of these capitalized amounts plus estimated finding and development costs 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 unevaluated leasehold or drilling interests and exploration drilling 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 for natural gas and oil properties, 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 at 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 may 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 of discounted revenues.

In the fourth quarter of 2008, we recorded ceiling test charges of $2.7 billion as a result of the decline in commodity prices. The calculation of these charges was based on the December 31, 2008 spot natural gas price of $5.71 per MMBtu and oil price of $44.60 per barrel. In calculating our ceiling test charges, we are required to hold these prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. During the first two months of 2009, natural gas and oil prices have declined from the levels at December 31, 2008. We may be required to record additional ceiling test charges in the future unless commodity prices significantly increase or oilfield service costs significantly decrease from their current levels.

In December 2008, the Securities and Exchange Commission (SEC) issued a final rule adopting revisions to its oil and gas reporting requirements. On December 31, 2009, we will adopt the provisions of the SEC s final rule. Among other things, the final rule will revise the definition of proved reserves and will require companies to use a twelve month average commodity price in determining future net revenues, rather than a period end price as is currently required. These changes, along with other proposed changes, will impact the manner in which we perform our full cost ceiling test calculation and determine any related charge. The provisions of this final rule are effective on December 31, 2009 and cannot be applied earlier than that date.

Cost-Based Regulation. We account for our regulated operations under the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management regularly assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. We periodically evaluate the applicability of SFAS No. 71, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to reduce certain of our asset balances to reflect a market basis lower than cost and write-off the associated regulatory assets.

Accounting for Legal and Environmental Reserves, Guarantees and Indemnifications. 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 an 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, 2008, we had accrued approximately $87 million for legal matters, which has not been reduced by $14 million of related insurance receivables. We have accrued $204 million for environmental matters. Our environmental estimates range from approximately $204 million to approximately $388 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 ($12 million). Second, where the most likely

outcome cannot be estimated, a range of costs is established ($192 million to $376 million) and the lower end of the expected range has been accrued.

We also have guarantee and indemnification agreements related to various joint ventures and other ownership arrangements that require us to assess our potential exposure. This exposure can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $797 million. As of December 31, 2008, we have recorded obligations of $62 million related to our guarantees and indemnification arrangements. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments under the agreement due to the uncertainty of these exposures. For further information, see *Off Balance Sheet Arrangements* above.

Accounting for Pension and Other Postretirement Benefits. 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, 2008, our pension plans were under funded by $216 million and our other postretirement benefit plans were under funded by $463 million. Our pension and other postretirement benefit obligations and net benefit costs 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 select our discount rates by matching the timing and amount of our expected future benefit payments for our pension and other postretirement benefit obligations to the average yields of various high-quality bonds with corresponding maturities.

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 and amortized into income over either the period of expected future service of active participants, or over the lives of the plan participants. We record these deferred amounts as accumulated other comprehensive income for our non-regulated operations and as either a regulatory asset or liability for our regulated operations. As of December 31, 2008 we had deferred net losses of approximately $745 million, net of income taxes, in accumulated other comprehensive income. 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, 2008 (in millions):

	Pension Benefits		Other Postretirement Benefits	
	Net Benefit Expense (Income)	**Change in Funded Status and Pretax Accumulated Other Comprehensive Income**	**Net Benefit Expense (Income)**	**Change in Funded Status and Pretax Accumulated Other Comprehensive Income**
One percent increase in:				
Discount rates	$(10)	$ 146	$	$ 50
Expected return on plan assets	(23)		(3)	
Rate of compensation increase	1	(5)		
Health care cost trends			3	(48)

One percent decrease in:				
Discount rates	$ 11	$ (170)	$ (1)	$ (54)
Expected return on plan assets[1]	23		3	
Rate of compensation increase	(1)	4		
Health care cost trends			(4)	44

(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 $18 million lower for the year ended December 31, 2008.

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. The extent to which we rely on pricing information received from third parties in developing these assumptions is based, in part, on whether the information considers the availability of observable data in the marketplace. For example, in relatively illiquid markets such as the PJM forward power market, we may make adjustments to the pricing information we receive from third parties based on our evaluation of whether third party market participants would use pricing assumptions consistent with these sources.

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 natural gas, oil and power prices at December 31, 2008:

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 682	$ 582	$ (100)	$ 785	$ 103
Other commodity-based derivatives	(707)	(719)	(12)	(695)	12
Total	$ (25)	$ (137)	$ (112)	$ 90	$ 115

Another significant assumption are the discount rates we use in determining the fair value of our derivative instruments. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from changes in the discount rates we used to determine the fair value of our derivatives at December 31, 2008:

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 682	$ 680	$ (2)	$ 684	$ 2
Other commodity-based derivatives	(707)	(689)	18	(726)	(19)
Total	$ (25)	$ (9)	$ 16	$ (42)	$ (17)

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to anticipated market liquidity and the credit and non-performance risk of our counterparties. We adjust the fair value of our derivative assets for the risk of non-performance of our counterparties considering the collateral posted for the derivative and changes in the counterparties creditworthiness, which is measured in part based on changes in their bond yields, changes in actively traded credit default swap prices (if available) and other information about their credit standing. We adjust the fair value of our derivative liabilities for our creditworthiness utilizing similar inputs including the consideration of non-cash collateral we have posted with our counterparties. On January 1, 2009, we will adopt the provisions of Emerging Issues Task Force Issue No. 08-5, which will require us to determine the fair value of our derivative liabilities without consideration of non-cash collateral. For a further description of this standard, see Item 8, Financial Statements and Supplementary Data, Note 1. We believe the application of these assumptions derive a fair value that is representative of the proceeds we would receive or pay if we disposed of our derivative instruments. 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. The actual settlement of our price risk management activities could also differ materially from the fair value recorded and could impact our future operating results.

Deferred Taxes and Uncertain Income Tax Positions. We record deferred income tax assets and liabilities reflecting tax consequences deferred to future periods based on differences between the financial statement carrying value of assets and liabilities and the tax basis of assets and liabilities. Additionally, our deferred tax assets and liabilities also reflect our assessment that tax positions taken, and the resulting tax basis, are more likely than not to be sustained if they are audited by taxing authorities. Our most significant judgments on tax related matters include, but are not limited to, the items noted below. All of these matters involve the exercise of significant judgment which could change and materially impact our financial condition or results of operations. For a further discussion of these items and other income tax matters, see Item 8, Financial Statements and Supplementary Data, Note 5.

Valuation Allowance. The realization of our deferred tax assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences are deductible. Valuation allowances are established when necessary to reduce deferred income tax assets to the amounts we believe are more likely than not to be recovered. In evaluating our valuation allowance, we consider the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowance could materially impact our results of operations.

Uncertain Tax Positions. We have liabilities for unrecognized tax benefits related to uncertain tax positions connected with ongoing examinations and open tax years. Changes in our assessment of these liabilities may require us to increase the liability and record additional tax expense or reverse the liability and recognize a tax benefit which would positively or negatively impact our effective tax rate.

Undistributed Earnings of Foreign Investees and Certain Unconsolidated Affiliates. We record deferred tax liabilities on the undistributed earnings of our foreign investments if we anticipate these earnings to be repatriated. If we do not plan to repatriate these foreign undistributed earnings, no provision has been made for any U.S. taxes or foreign withholding taxes. Any changes to our repatriation assumptions, including the repatriation of proceeds from sales of these investments, could require us to record additional deferred taxes.

Additionally, we believe certain of our unconsolidated affiliates undistributed earnings will ultimately be distributed to us through dividends which would be eligible for a dividends received deduction. We and our joint venture partners have the intent and ability to recover these cumulative undistributed earnings over time through dividends; however, should we subsequently determine that our unconsolidated affiliates would be unable to pay such dividends, we would be required to record additional deferred income tax liabilities.

Asset and Investment Impairments. The accounting rules on asset and investment impairments require us to continually monitor our businesses, the business environment and the performance of our investments 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 and discount rates. The assessment of project level cash flows requires significant 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 that are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can, and often do, differ from our estimates.

We utilize the cash flow projections to assess our ability to recover the carrying value of our assets and investments 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 and whether any decline in this fair value below our carrying amount is considered to be other than temporary. If an impairment is indicated, we record an impairment charge for the excess of carrying value of the asset over its fair value. We recorded impairments of our long-lived assets of $41 million, $20 million and $16 million and impairments and losses on our investments in and advances to unconsolidated affiliates of $127 million, $75 million and $13 million during the years ended December 31, 2008, 2007 and 2006. We also recorded asset and investment impairments of our discontinued operations of $13 million, net of minority interest during the year ended December 31, 2006. 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.*

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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

- Changes in natural gas and oil prices impact the sale of natural gas and oil in our Exploration and Production segment, affect gas not used in the operations of our Pipelines segment and affect the fair value of our natural gas and oil derivative contracts held in our Exploration & Production and Marketing segments;

- Changes in natural gas locational price differences affect our ability to optimize pipeline transportation capacity contracts held in our Marketing segment; and

- Changes in electricity prices and locational price differences affect the value of our 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; and

- Weakening or strengthening of the U.S. dollar relative to the Brazilian real and the Mexican peso can affect the revenues and expenses generated by our foreign pipeline, exploration and production, and power operations.

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 are 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.

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Commodity Price Risk

Production-Related Derivatives

We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risks of 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.

Other Commodity-Based Derivatives

In our Marketing segment, we have long-term derivative contracts which include forwards, swaps, options and futures, that we either intend to assign to third parties or manage until their expiration. Prior to 2008, we managed these contracts on a daily basis using a Value-at-Risk simulation. During 2008, we began utilizing a sensitivity analysis to manage the commodity price risk associated with our other commodity-based derivative contracts and discontinued using the Value-at-Risk simulation based on the continued simplification of our derivative portfolio and the gradual discontinuance of a substantial majority of our trading activities.

Sensitivity Analysis

The table below presents the hypothetical sensitivity of our production-related derivatives and our other commodity-based derivatives to changes in fair values arising from immediate selected potential changes in the market prices (primarily natural gas, oil and power prices and basis differentials) used to value these contracts. This table reflects the sensitivities of the derivative contracts only and does not include any underlying hedged commodities.

		Change in Market Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives net assets (liabilities)					
December 31, 2008	$ 682	$ 582	$ (100)	$ 785	$103
December 31, 2007	$ (64)	$(181)	$ (117)	$ 58	$122
Other commodity-based derivatives net assets (liabilities)					
December 31, 2008	$(707)	$(719)	$ (12)	$(695)	$ 12
December 31, 2007	$(828)	$(846)	$ (18)	$(810)	$ 18

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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 effective interest rates on our long-term interest-bearing securities by expected maturity date 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, 2008								December 31, 2007	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2009	2010	2011	2012	2013	Thereafter	Total	Value	Amounts	Value
	(In millions)									
Long-term debt and other obligations, including current portion fixed rate	$1,076	$239	$663	$ 459	$ 538	$8,653	$11,628	$9,438	$10,945	$11,244
Average interest rate	6.3%	8.3%	7.5%	8.0%	14.6%	7.4%				
Long-term debt and other obligations, including current portion variable rate	$ 14	$ 15	$ 16	$2,072	$ 18	$ 145	$ 2,280	$1,789	$ 1,869	$ 1,869
Average interest rate	5.9%	5.9%	5.9%	4.1%	5.9%	5.9%				

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, 2008 and 2007, we have Euro-denominated debt with a principal amount of 380 million which matures in May 2009. We have swaps that effectively convert 330 million of debt into $379 million as of December 31, 2008 and December 31, 2007. The remaining principal of 50 million at December 31, 2008 and 2007 is subject to foreign currency exchange risk. A $0.10 change in the Euro to U.S. dollar exchange rate would result in a $5 million gain or loss on our unhedged Euro-denominated debt as of December 31, 2008.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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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, 2008. 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, 2008. The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited the accompanying consolidated balance sheets of El Paso Corporation as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15(a). 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 audits. The financial statements of Citrus Corp. and Subsidiaries (a corporation in which the Company had a 50% interest as of December 31, 2008, 2007, and 2006) and Four Star Oil & Gas Company (a corporation in which the Company had approximately a 49% interest as of December 31, 2008 and 2007, and a 43% interest as of December 31, 2006) 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 from 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 include approximately $744 million and $736 million at December 31, 2008 and 2007, respectively, and the Company s combined earnings from unconsolidated affiliates from these companies include approximately $147 million, $149 million, and $126 million for each of the three years in the period ended December 31, 2008, which were audited by other auditors.

We conducted our audits 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 audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008 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, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2008 the Company adopted the measurement 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),* effective January 1, 2007, the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109,* 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), El Paso Corporation s internal control over financial reporting as of December 31, 2008, 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, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
El Paso Corporation:

We have audited El Paso Corporation s internal control over financial reporting as of December 31, 2008, 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 included in the accompanying Management s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, El Paso Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2008 consolidated financial statements of El Paso Corporation and our report dated February 26, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2009

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Report of Independent Registered Public Accounting Firm

To the Stockholders of Four Star Oil & Gas Company:

In our opinion, the consolidated balance sheets and the related consolidated statements of income, of stockholders equity and of cash flows (not presented separately herein) present fairly, in all material respects, the financial position of Four Star Oil & Gas Company (the Company) and its subsidiary at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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 Notes 3 and 4 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

Houston, Texas
February 20, 2009

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated balance sheets and the related consolidated statements of income, of comprehensive income, of stockholders equity and of cash flows (not presented separately herein) present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the Company) at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2009

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

	Year Ended December 31,		
	2008	2007	2006
Operating revenues			
Pipelines	$ 2,684	$ 2,494	$ 2,402
Exploration and Production	2,762	2,300	1,854
Marketing	(83)	(219)	(58)
Power			6
Corporate and eliminations		73	77
	5,363	4,648	4,281
Operating expenses			
Cost of products and services	245	245	238
Operation and maintenance	1,190	1,333	1,337
Ceiling test charges	2,669		
Depreciation, depletion and amortization	1,205	1,176	1,047
Taxes, other than income taxes	284	249	232
	5,593	3,003	2,854
Operating income (loss)	(230)	1,645	1,427
Earnings from unconsolidated affiliates	48	101	145
Loss on debt extinguishment		(291)	(26)
Other income	94	214	245
Other expenses	(32)	(11)	(40)
Minority interests	(34)	(6)	(1)
Interest and debt expense	(914)	(994)	(1,228)
Income (loss) before income taxes from continuing operations	(1,068)	658	522
Income tax expense (benefit)	(245)	222	(9)
Income (loss) from continuing operations	(823)	436	531
Discontinued operations, net of income taxes		674	(56)
Net income (loss)	(823)	1,110	475
Preferred stock dividends	37	37	37
Net income (loss) available to common stockholders	$ (860)	$ 1,073	$ 438
Basic earnings (loss) per common share			
Income (loss) from continuing operations	$ (1.24)	$ 0.57	$ 0.73
Discontinued operations, net of income taxes		0.97	(0.08)
Net income (loss) per common share	$ (1.24)	$ 1.54	$ 0.65

Diluted earnings (loss) per common share			
Income (loss) from continuing operations	$ (1.24)	$ 0.57	$ 0.72
Discontinued operations, net of income taxes		0.96	(0.08)
Net income (loss) per common share	$ (1.24)	$ 1.53	$ 0.64

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,024	$ 285
Accounts and notes receivable		
Customer, net of allowance of $9 in 2008 and $17 in 2007	466	468
Affiliates	133	196
Other	217	201
Materials and supplies	187	131
Assets from price risk management activities	876	113
Deferred income taxes		191
Other	148	127
Total current assets	3,051	1,712
Property, plant and equipment, at cost		
Pipelines	18,042	16,750
Natural gas and oil properties, at full cost	20,009	19,048
Other	342	530
	38,393	36,328
Less accumulated depreciation, depletion and amortization	20,535	16,974
Total property, plant and equipment, net	17,858	19,354
Other assets		
Investments in unconsolidated affiliates	1,703	1,614
Assets from price risk management activities	201	302
Other	855	1,597
	2,759	3,513
Total assets	$ 23,668	$ 24,579

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 372	$ 460
Affiliates	6	5
Other	674	502
Short-term financing obligations, including current maturities	1,090	331
Liabilities from price risk management activities	250	267
Accrued interest	192	195
Other	659	653
Total current liabilities	3,243	2,413
Long-term financing obligations, less current maturities	12,818	12,483
Other		
Liabilities from price risk management activities	767	931
Deferred income taxes	565	1,157
Other	1,679	1,750
	3,011	3,838
Commitments and contingencies (Note 13)		
Minority interests	561	565
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 712,628,781 shares in 2008 and 709,192,605 shares in 2007	2,138	2,128
Additional paid-in capital	4,612	4,699
Accumulated deficit	(2,653)	(1,834)
Accumulated other comprehensive loss	(532)	(272)
Treasury stock (at cost); 14,061,474 shares in 2008 and 8,656,095 shares in 2007	(280)	(191)
Total stockholders equity	4,035	5,280
Total liabilities and stockholders equity	$ 23,668	$ 24,579

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31, 2008	2007	2006
Cash flows from operating activities			
Net income (loss)	$ (823)	$ 1,110	$ 475
Less income (loss) from discontinued operations, net of income taxes		674	(56)
Net income (loss) from continuing operations	(823)	436	531
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	1,205	1,176	1,047
Ceiling test charges	2,669		
Deferred income tax expense (benefit)	(172)	182	(20)
Earnings from unconsolidated affiliates, adjusted for cash distributions	132	88	(6)
Loss on debt extinguishment		291	26
Other non-cash income items	66	(25)	72
Asset and liability changes			
Accounts and notes receivable	129	213	344
Change in price risk management activities, net	(461)	(69)	(420)
Accounts payable	(88)	(67)	(382)
Change in margin and other deposits	24	90	911
Other asset changes	(32)	(150)	(179)
Other liability changes	(279)	(327)	(100)
Cash provided by continuing activities	2,370	1,838	1,824
Cash provided by (used in) discontinued activities		(33)	279
Net cash provided by operating activities	2,370	1,805	2,103
Cash flows from investing activities			
Capital expenditures	(2,757)	(2,495)	(2,164)
Cash paid for acquisitions, net of cash acquired	(362)	(1,197)	
Net proceeds from the sale of assets and investments	682	106	673
Net change in restricted cash	39	33	129
Other	50	3	23
Cash used in continuing activities	(2,348)	(3,550)	(1,339)
Cash provided by discontinued activities		3,660	185
Net cash provided by (used in) investing activities	(2,348)	110	(1,154)
Cash flows from financing activities			
Net proceeds from issuance of long-term debt	4,641	6,624	375
Payments to retire long-term debt and other financing obligations	(3,679)	(8,902)	(3,024)
Net proceeds from issuance of subsidiary equity	15	538	
Net proceeds from the issuance of common stock			500
Dividends paid	(157)	(149)	(145)

Payments to minority interest holders	(29)		(5)
Repurchase of shares	(77)		
Contributions from discontinued operations		3,344	232
Other	3	5	(13)
Cash provided by (used in) continuing activities	717	1,460	(2,080)
Cash used in discontinued activities		(3,627)	(464)
Net cash provided by (used in) financing activities	717	(2,167)	(2,544)
Change in cash and cash equivalents	739	(252)	(1,595)
Cash and cash equivalents			
Beginning of period	285	537	2,132
End of period	$ 1,024	$ 285	$ 537
Supplemental cash flow information related to continuing operations			
Interest paid, net of amounts capitalized	$ 914	$ 1,054	$ 1,217
Income tax payments	12	34	77

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In millions)

	Year Ended December 31,					
	2008		2007		2006	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred stock, $0.01 par value:						
Balance at beginning and end of year	1	$ 750	1	$ 750	1	$ 750
Common stock, $3.00 par value:						
Balance at beginning of year	709	2,128	706	2,118	667	2,001
Equity offering					36	107
Other, net	3	10	3	10	3	10
Balance at end of year	712	2,138	709	2,128	706	2,118
Additional paid-in capital:						
Balance at beginning of year		4,699		4,804		4,592
Equity offering						393
Dividends		(163)		(149)		(147)
Other, including stock-based compensation		76		44		(34)
Balance at end of year		4,612		4,699		4,804
Accumulated deficit:						
Balance at beginning of year		(1,834)		(2,940)		(3,415)
Net income (loss)		(823)		1,110		475
Cumulative effect of adopting of FIN No. 48				(4)		
Cumulative effect of adopting SFAS No. 158, net of income tax of $2		4				
Balance at end of year		(2,653)		(1,834)		(2,940)
Accumulated other comprehensive income (loss):						
Balance at beginning of year		(272)		(343)		(332)
Other comprehensive income (loss)		(263)		80		380
Cumulative effect of adopting SFAS No. 158, net of income tax of $2 in 2008, $4 in 2007 and $210 in 2006		3		(9)		(391)

Balance at end of year		(532)		(272)		(343)
Treasury stock, at cost:						
Balance at beginning of year	(9)	(191)	(9)	(203)	(8)	(190)
Share repurchases	(5)	(77)				
Stock-based and other compensation		(12)		12	(1)	(13)
Balance at end of year	(14)	(280)	(9)	(191)	(9)	(203)
Unamortized compensation:						
Balance at beginning of year						(17)
Adoption of SFAS No. 123(R)						17
Balance at end of year						
Total stockholders equity		$ 4,035		$ 5,280		$ 4,186

See accompanying notes.

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EL PASO CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2008	2007	2006
Net income (loss)	$ (823)	$ 1,110	$ 475
Pension and postretirement obligations:			
Unrealized actuarial gains (losses) arising during period (net of income taxes of $288 in 2008, $91 in 2007 and $3 in 2006)	(527)	181	5
Reclassifications of actuarial gains and losses during period (net of income taxes of $8 in 2008 and $13 in 2007)	16	26	
Cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $106 in 2008, $2 in 2007 and $196 in 2006)	191	(3)	352
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $31 in 2008, $65 in 2007 and $15 in 2006)	57	(112)	22
Investments available for sale:			
Unrealized gains on investments available for sale arising during period (net of income taxes of $2 in 2007 and $16 in 2006)		3	28
Realized gains on investments available for sale arising during period (net of income taxes of $8 in 2007 and $17 in 2006)		(15)	(31)
Other			4
Other comprehensive income (loss)	(263)	80	380
Comprehensive income (loss)	$ (1,086)	$ 1,190	$ 855

See accompanying notes.

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EL PASO CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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 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 Federal Energy Regulatory Commission (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 related to gas not used in operations and other 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, 2008, we had $2 million of restricted cash in current assets and $57 million in other non-current assets. As of December 31, 2007, we had $7 million of restricted cash in other current assets and $91 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.

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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 major units of property replacements or improvements and expense minor items. For a description of the methods we use to depreciate regulated property, plant and equipment, see Note 11.

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 countries where a natural gas or oil reserve base exists, we transfer unproved property costs to the amortizable base when we have completed the evaluation of the unproved properties or they are determined to be impaired and as exploratory wells are determined to be unsuccessful. Additionally, the amortizable base includes future development costs; 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 in each country, 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 may 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 any derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production on the date of the calculation. 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) the long-lived asset s ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. 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 the asset 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 sale, among other factors.

We reclassify the assets (or groups of assets) to be sold as either held-for-sale or from 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. We make contributions to our plans, if required, to fund the benefits to be paid out to participants and retirees. These contributions are invested until the benefits are paid out to plan participants. We record the net benefit cost related to these plans in our income statement. This net benefit cost 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 began accounting for our pension and other postretirement benefit plans under 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)* and recorded a $391 million increase, net of income taxes of $210 million, to accumulated other comprehensive loss related to the adoption of this standard. Under SFAS No. 158, we record an asset or liability for our pension and other postretirement benefit plans based on their over funded or under funded status. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded either as a regulatory asset or liability for our regulated operations or in accumulated other comprehensive income (loss), a component of stockholders equity, for our nonregulated operations until those gains and losses are recognized in the income statement.

Effective January 1, 2008, we adopted the measurement date provisions of SFAS No. 158 and changed the measurement date of our pension and other postretirement benefit plans from September 30 to December 31. We recorded a $4 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated deficit and a $3 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated other comprehensive loss upon the adoption of the measurement date provisions of this standard to reflect an additional three months of net periodic benefit income based on our September 30, 2007 measurement. For a further discussion of our application of SFAS No. 158, see Note 14.

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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. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. 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 from our shippers when we retain the volumes at the market prices required under our tariffs. 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 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 reserves for a given property, we record a liability. Costs associated with the transportation and delivery of production are included in cost of products and services.

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 contracts, 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 as 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 relate primarily to 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. We also hold other derivatives not intended to hedge these exposures, including those related to our legacy trading activities.

Our derivatives are reflected on our balance sheet at their fair value as assets and liabilities from price risk management activities. Cash collateral associated with our derivatives are not significant to our financial statements. 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, as well as any realized amounts, are reflected as operating revenues in both our Exploration and Production segment and our Marketing segment.

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.

Effective January 1, 2007, we began applying the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*, which clarifies SFAS No. 109, *Accounting for Income Taxes,* and recorded a $4 million increase to the January 1, 2007 accumulated deficit balance and an increase of $2 million to additional paid-in-capital related to the adoption of this standard. This standard 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 effective settlement. For a further discussion of the impact of our application of FIN No. 48, see Note 5.

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Accounting for Asset Retirement Obligations

We account for our asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* and 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 in the period the obligation is incurred. 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 as 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.

We measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in our financial statements over the requisite service period. For additional information on our stock-based compensation awards, see Note 16.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2008, the following accounting standards and interpretations had not yet been adopted by us.

Fair Value Measurements. We have adopted the provisions of SFAS No. 157, *Fair Value Measurements* in measuring the fair value of financial assets and liabilities in the financial statements. We have elected to defer the adoption of SFAS No. 157 for certain of our non-financial assets and liabilities until January 1, 2009, the adoption of which will not have a material impact on our financial statements.

In September 2008, the Emerging Issues Task Force issued Issue No. 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement,* which provides guidance to companies about how they should consider their own credit in determining the fair value of their liabilities that have third party credit enhancements related to them. This standard requires that non-cash credit enhancements such as letters of credit, should not be considered in determining the fair value of liabilities, including derivative liabilities. We will adopt the provisions of this standard during the first quarter of 2009, and we are currently evaluating the impact that this standard will have on our financial statements.

Business Combinations. In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*, which provides revised guidance on the accounting for acquisitions of businesses. This standard changes the current guidance to require that all acquired assets, liabilities, minority interest and certain contingencies be measured at fair value, and certain other acquisition-related costs be expensed rather than capitalized. SFAS No. 141(R) will apply to acquisitions that are effective after December 31, 2008, and application of the standard to acquisitions prior to that date is not permitted.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which provides guidance on the presentation of minority interest, subsequently renamed noncontrolling interest, in the financial statements. This standard requires that noncontrolling interest be presented as a separate component of equity rather than as a mezzanine item between liabilities and equity, and also requires that noncontrolling interest be presented as a separate caption in the income statement. This standard also requires all transactions with noncontrolling interest holders, including the issuance and repurchase of noncontrolling interests, be accounted for as equity transactions unless a change in control of the subsidiary occurs. We will adopt the provisions of this standard effective January 1, 2009, which will impact the presentation of noncontrolling interests in our balance sheets and income statements.

Oil and Gas Reserves Reporting. In December 2008, the Securities and Exchange Commission (SEC) issued a final rule adopting revisions to its oil and gas reporting requirements. The revisions will impact the determination and disclosure of oil and gas reserves information. Among other things, the new rules will revise the definition of proved reserves and will require companies to use a twelve month average commodity price in determining future net revenues, rather than a period end price as is currently required. These changes, along with other proposed changes, will impact the manner in which we perform our full cost ceiling test calculation and determine any related charge. The provisions of this final rule are effective on December 31, 2009, and cannot be applied earlier than that date. We are currently assessing the impact that this final rule may have on our determination and disclosure of oil and gas reserves information.

2. Acquisitions and Divestitures

Acquisitions

Gulf LNG. In February 2008, we paid $295 million to complete the acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, a liquefied natural gas (LNG) terminal which is currently under construction in Pascagoula, Mississippi. The terminal is expected to be placed in service in late 2011 at an estimated total cost of $1.1 billion. In addition, we have a commitment to loan Gulf LNG up to $150 million under which we have advanced approximately $26 million as of December 31, 2008. Our partner in this project has a commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

Exploration and Production properties. During the year ended December 31, 2008, we acquired interests in domestic natural gas and oil properties for $61 million, including producing properties of $51 million. During 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas for $254 million and also acquired Peoples Energy Production Company (Peoples) for $887 million. Peoples was an exploration and production company with natural gas and oil properties located primarily in the Arklatex, Texas Gulf Coast and Mississippi areas and in the San Juan and Arkoma Basins.

Divestitures

During 2008, 2007 and 2006, we sold a number of assets and investments in each of our business segments and corporate activities. The table and discussions below summarize the assets sold and proceeds from these sales:

	2008	2007	2006
		(In millions)	
Exploration and Production	$ 637	$ 2	$ 122
Power	16	1	531
Marketing		24	
Pipelines	2	36	3
Corporate	20	3	2
Total continuing[(1)]	675	66	658
Discontinued		3,660	368
Total	$ 675	$ 3,726	$ 1,026

(1) Proceeds exclude any returns of capital on our investments in unconsolidated affiliates and cash transferred

with the assets sold and include costs incurred in preparing assets for disposal. These items increased our sales proceeds by $7 million, $40 million and $15 million for the years ended December 31, 2008, 2007 and 2006.

Exploration and Production. Assets sold in 2008 consisted primarily of natural gas and oil properties in the Gulf of Mexico and Texas Gulf Coast regions and the sales in 2006 consisted of natural gas and oil properties in south Texas.

Power. Assets sold in 2008 consist of power investments in Central America and Asia. Assets sold in 2006 consisted primarily of our interests in the Midland Cogeneration Venture and power plants in Brazil, Asia, and Central America.

Marketing, Pipelines and Corporate. Assets sold consisted primarily of a fuel oil terminal in 2008 and our investment in the New York Mercantile Exchange and our Stagecoach Pipeline lateral 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 (or groups of assets) to be disposed of as held for sale or, if appropriate, from 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, 2007 and 2006. As of December 31, 2007, all of our assets and liabilities related to our discontinued operations and assets held for sale had been sold.

ANR and Related Operations. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for approximately $3.7 billion. We recorded a gain on the sale of $648 million, net of taxes of $354 million. Included in the net assets of these discontinued operations as of the date of sale were net deferred tax liabilities assumed by the purchaser. We also recorded approximately $188 million of deferred taxes in 2006 in conjunction with the sale.

International Power Operations. During 2006, we completed the sale of all of our discontinued international power operations including Macae, a wholly owned power plant facility in Brazil, and Asian and Central American power assets for total net proceeds of approximately $368 million.

Income Taxes on Discontinued Operations. For the years ended December 31, 2007 and 2006, we incurred income tax expense associated with our discontinued operations of $369 million and $274 million resulting in an effective tax rate on discontinued operations of approximately 35% and 126% for these years. The effective tax rate in 2006 was significantly higher than the statutory rate of 35% primarily due to $188 million of deferred taxes that were recorded upon our agreement 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 only recorded deferred taxes on individual assets/liabilities and a portion of our investment in the stock of one of these companies.

The summarized operating results of our discontinued operations were as follows:

	ANR and Related Operations	International Power Operations	Other	Total
		(In millions)		
Year Ended December 31, 2007				
Revenues	$ 101	$	$	$ 101
Costs and expenses	(43)			(43)
Other expense[1]	(7)			(7)
Interest and debt expense	(10)			(10)
Income taxes	(15)			(15)
Income from operations				26
Gain on sale, net of income taxes of $354 million				648
Income from discontinued operations, net of income taxes				$ 674
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 taxes					(274)
Loss from discontinued operations, net of income taxes				$	(56)

(1) Includes a loss of approximately $19 million associated with the extinguishment of certain debt obligations.

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3. Ceiling Test Charges

In the fourth quarter of 2008, we recorded a reduction to our property, plant and equipment due to non-cash ceiling test charges of $2.7 billion that resulted from declines in commodity prices. Capitalized costs exceeded the ceiling limit by $2.2 billion for our domestic full cost pool and $0.5 billion for our Brazilian full cost pool. The calculation of these charges was based on the December 31, 2008 spot natural gas price of $5.71 per MMBtu and oil price of $44.60 per barrel. In calculating our ceiling test charges, we are required to hold these prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. During the first two months of 2009, natural gas and oil prices have declined from the levels at December 31, 2008. We may be required to record additional ceiling test charges in the future unless commodity prices significantly increase or oilfield service costs significantly decrease from their current levels.

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:

	2008	2007	2006
		(In millions)	
Other Income			
Interest income	$ 19	$ 49	$ 138
Allowance for funds used during construction	37	32	20
Deferred taxes on capitalized funds used during construction	17	18	11
Reversal of liability for legacy crude oil purchases (see Note 13)		77	
Gain on sale of non-equity method investments		24	47
Other	21	14	29
Total	$ 94	$ 214	$ 245
Other Expenses			
Foreign currency losses	$ 28	$ 1	$ 20
Loss on sale of non-equity method investments			12
Other	4	10	8
Total	$ 32	$ 11	$ 40

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:

	2008	2007	2006
		(In millions)	
Pretax Income (Loss)			
U.S	$ (603)	$ 587	$ 442
Foreign	(465)	71	80
	$ (1,068)	$ 658	$ 522
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ (36)	$ (1)	$ 7
State	(38)	33	(15)

Foreign	1	8	19
	(73)	40	11
Deferred			
Federal	(238)	217	(46)
State	27	(39)	32
Foreign	39	4	(6)
	(172)	182	(20)
Total income tax expense (benefit)	$ (245)	$ 222	$ (9)

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Effective Tax Rate Reconciliation. Our income taxes, included in income 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:

	2008	2007	2006
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$ (374)	$ 230	$ 183
Increase (decrease)			
Audit settlements	2		(159)
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(41)	(40)	(35)
Texas margins tax credit on accumulated net operating loss		(16)	
State income taxes, net of federal income tax effect	(6)	14	20
Sales and write-offs of foreign investments	(50)	1	(17)
Foreign income (loss) taxed at different rates	23	24	(13)
Valuation allowances	202	10	23
Other	(1)	(1)	(11)
Income taxes	$ (245)	$ 222	$ (9)
Effective tax rate	23%	34%	(2)%

In 2008, our overall effective tax rate differed from the statutory rate due primarily to a $0.5 billion ceiling test charge on our Brazilian full cost pool that did not have a corresponding U.S. or Brazilian tax benefit. The impact of the ceiling test charge on our effective tax rate is included in *Foreign income (loss) taxed at different rates* and *Valuation allowances* in the above table. In 2006, our effective tax rate on continuing operations was significantly different than the statutory rate due primarily to the conclusion of IRS audits of The Coastal Corporation s 1998-2000 tax years and El Paso s 2001 and 2002 tax years which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits.

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

	2008	2007
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 2,775	$ 3,106
Investments in affiliates	178	227
Benefits and compensation		58
Regulatory and other assets	63	49
Total deferred tax liability	3,016	3,440
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,315	1,135
State	178	188
Foreign	147	105
Benefits and compensation	356	
Price risk management activities	112	439

Legal and other reserves	205	321
Other	465	464
Valuation allowance	(337)	(137)
Total deferred tax asset	2,441	2,515
Net deferred tax liability	$ 575	$ 925

Cumulative undistributed earnings from substantially all of our foreign subsidiaries and foreign corporate joint ventures 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, 2008, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $110 million.

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Unrecognized Tax Benefits (Liabilities) for Uncertain Tax Matters (FIN No. 48). We are subject to taxation in the U.S. and various states and foreign jurisdictions. With a few exceptions, we are no longer subject to state, local or foreign income tax examinations by tax authorities for years prior to 1999 and U.S. income tax examinations for years prior to 2005. In June 2008, the Internal Revenue Service s examination of El Paso s U.S. income tax returns for 2003 and 2004 was settled at the appellate level with approval by the Joint Committee on Taxation. The settlement of issues raised in this examination did not materially impact our results of operations, financial condition or liquidity. For years in which our returns are still subject to review, our unrecognized tax benefits (liabilities for uncertain tax matters) could increase or decrease our income tax expense and effective income tax rates as these matters are finalized. We are currently unable to estimate the range of potential impacts the resolution of any contested matters could have on our financial statements.

Upon the adoption of FIN No. 48, we recorded additional liabilities for unrecognized tax benefits of $2 million, including interest and penalties, which we accounted for as an increase of $4 million to the January 1, 2007 accumulated deficit and an increase of $2 million to additional paid-in capital. The following table shows the change in unrecognized tax benefits:

	2008	2007
	(In millions)	
Balance at January 1	$ 157	$ 139
Additions:		
Tax positions taken in prior years	24	2
Tax positions taken in current year	32	23
Foreign currency fluctuations		1
Reductions:		
Tax positions taken in prior years	(23)	(5)
Settlements with taxing authorities	(11)	(3)
Statute of limitations expiration	(5)	
Foreign currency fluctuations	(1)	
Balance at December 31	$ 173	$ 157

As of December 31, 2008, and 2007, approximately $169 million and $132 million (net of federal tax benefits) of unrecognized tax benefits would affect our income tax expense and our effective income tax rate if recognized in future periods. While the amount of our unrecognized tax benefits could change in the next twelve months, we do not expect this change to have a significant impact on our results of operations or financial position.

We recognize interest accrual related to unrecognized tax benefits and penalties as income tax expense. During 2008 and 2007, we recognized $4 million and $6 million in interest related to the unrecognized tax benefits noted above. We had $49 million and $45 million accrued for the payment of interest and penalties as of December 31, 2008 and 2007.

Tax Credit and NOL Carryovers. As of December 31, 2008, we have U.S. federal alternative minimum tax credits of $314 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2008:

	Carryover Period				
	2009	2010-2013	2014-2018	2019-2028	Total
			(In millions)		
U.S. federal net operating loss	$ 1	$ 18	$ 19	$2,964	$ 3,002]
State net operating loss	349	577	714	1,120	2,760

We also had $381 million of foreign net operating loss carryovers and $53 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.

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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 2008, we provided a valuation allowance of $202 million on deferred tax assets associated with Brazil net operating losses and ceiling test charges. The valuation allowance was established primarily as a result of changes in the worldwide economic conditions creating uncertainty in our outlook as to future taxable income in that particular tax jurisdiction. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

6. Earnings Per Share

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

	2008		2007		2006	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)					
Income (loss) from continuing operations	$ (823)	$ (823)	$ 436	$ 436	$ 531	$ 531
Convertible preferred stock dividends	(37)	(37)	(37)	(37)	(37)	
Income (loss) from continuing operations available to common stockholders	(860)	(860)	399	399	494	531
Discontinued operations, net of income taxes			674	674	(56)	(56)
Net income (loss) available to common stockholders	$ (860)	$ (860)	$ 1,073	$ 1,073	$ 438	$ 475
Weighted average common shares outstanding	696	696	696	696	678	678
Effect of dilutive securities:						
Options and restricted stock				3		4
Convertible preferred stock						57
Weighted average common shares outstanding and dilutive potential common shares	696	696	696	699	678	739
Earnings per common share:						
Income (loss) from continuing operations	$ (1.24)	$ (1.24)	$ 0.57	$ 0.57	$ 0.73	$ 0.72
Discontinued operations, net of income taxes			0.97	0.96	(0.08)	(0.08)
Net income (loss)	$ (1.24)	$ (1.24)	$ 1.54	$ 1.53	$ 0.65	$ 0.64

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, trust preferred securities, and zero coupon convertible debentures (which were paid off in April 2006). For the year ended December 31, 2008, 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 the year ended December 31, 2007 and 2006, certain employee stock options and our trust preferred securities were antidilutive. Additionally, in 2006, our zero coupon convertible debentures (redeemed in April 2006) were antidilutive and in 2007 our convertible preferred stock 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.

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7. Fair Value of Financial Instruments

On January 1, 2008, we adopted the provisions of SFAS No. 157, *Fair Value Measurements*, and SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, for our financial assets and liabilities. SFAS No. 157 expands the disclosure requirements for financial instruments and other derivatives recorded at fair value, and also requires that a company s own credit risk be considered in determining the fair value of those instruments. The adoption of SFAS No. 157 resulted in a $6 million increase in operating revenues, a $4 million pre-tax increase in other comprehensive income, and a $10 million reduction of our liabilities to reflect the consideration of our credit risk on our liabilities that are recorded at fair value, after considering collateral related to these positions. SFAS No. 159 had no impact on our financial statements as we elected not to apply fair value accounting at adoption for our applicable financial assets and liabilities.

We use various methods to determine the fair values of our financial instruments and other derivatives which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments and other derivatives into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels. Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 instruments fair values are based on quoted prices for the instruments in actively traded markets. Included in this level are our marketable securities invested in non-qualified compensation plans whose fair value is determined using the quoted prices of these instruments.

Level 2 instruments fair values are primarily based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets). Included in this level are our foreign currency and interest rate swaps. Also included in this level are our production-related natural gas and oil derivatives and certain of our other natural gas derivatives (such as natural gas supply arrangements) whose fair values are based on commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties (adjusted for collateral related to those positions).

Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but their fair value also reflects adjustments for being in less liquid markets or having longer contractual terms. For these instruments, we obtain pricing data from third party pricing sources, adjust this data based on the liquidity of the underlying forward markets over the contractual terms and use the adjusted pricing data to develop an estimate of forward price curves that market participants would use. The curves are then used to estimate the value of settlements in future periods based on contractual settlement quantities and dates. Our valuation of these instruments considers specific contractual terms, statistical and simulation analysis, present value concepts and other internal assumptions related to (i) contract maturities that extend beyond the periods in which quoted market prices are available; (ii) the uniqueness of the contract terms; (iii) the limited availability of forward pricing information in markets where there is a lack of viable participants, such as in the PJM forward power market and the forward market for ammonia; and (iv) our creditworthiness or that of our counterparties (adjusted for collateral related to those positions). Since a significant portion of the fair value of our power-related derivatives and certain of our remaining natural gas derivatives with longer terms or in less liquid markets than similar Level 2 derivatives, rely on the techniques discussed above, we classify these instruments as Level 3 instruments.

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Listed below are the fair values of our financial instruments that are recorded at fair value classified in each level at December 31, 2008 (in millions):

	Level 1	Level 2	Level 3	Total
Assets				
Commodity-based derivatives				
Production-related natural gas and oil derivatives	$	$ 727	$	$ 727
Other natural gas derivatives		141	31	172
Power-related derivatives			72	72
Foreign currency derivatives		106		106
Marketable securities invested in non-qualified compensation plans	19			19
Total assets	$ 19	$ 974	$ 103	$ 1,096

	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity-based derivatives				
Production-related natural gas and oil derivatives	$	$ (45)	$	$ (45)
Other natural gas derivatives		(255)	(186)	(441)
Power-related derivatives			(510)	(510)
Interest rate derivatives		(21)		(21)
Other			(55)	(55)
Total liabilities		(321)	(751)	(1,072)
Total	$ 19	$ 653	$ (648)	$ 24

On certain derivative contracts recorded as assets we are exposed to the risk that our counterparties may not be able to perform or post the required collateral, if any, with us. We have assessed this counterparty risk in light of the collateral our counterparties have posted with us and the recent instability in the credit markets. Based on this assessment, we have determined that our exposure is primarily related to our production-related derivatives and foreign currency swaps and is limited to five financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

The following table presents the changes in our financial assets and liabilities included in Level 3 for the year ended December 31, 2008 (in millions):

	Balance at	Change in fair value reflected in operating	Change in fair value reflected in operating	Change in fair value reflected in long-term financing	Settlements,

	Beginning of Period	revenues[1]	expenses[2]	obligations[3]	Transfers[4]	Net	Balance at End of Period
Assets	$ 250	$ 2	$	$ (24)	$ (85)	$ (40)	$ 103
Liabilities	(839)	(57)	(19)			164	(751)
Total	$ (589)	$ (55)	$ (19)	$ (24)	$ (85)	$ 124	$ (648)

(1) Includes approximately $46 million of net losses that had not been realized through settlements for the year ended December 31, 2008.

(2) Includes approximately $19 million of net losses that had not been realized through settlements for the year ended December 31, 2008.

(3) Includes approximately $24 million of net losses that had not been realized through settlements for the year ended December 31, 2008.

(4) We transferred our foreign currency swaps and certain of our interest rate swaps out of Level 3 based on additional

information
received about
their fair values
during 2008.

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The following table reflects the carrying value and fair value of our financial instruments:

	As of December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$13,908	$11,227	$12,814	$13,113
Marketable securities invested in non-qualified compensation plans	19	19	20	20
Commodity-based derivatives	(25)	(25)	(892)	(892)
Interest rate and foreign currency derivatives	85	85	109	109
Other	72	72	64	64

As of December 31, 2008 and 2007, 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 carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on their interest rates and our assessment of our ability to recover these amounts. We estimated the fair value of debt based on quoted market prices for the same or similar issues, including consideration of our credit risk related to those instruments.

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, 2008 and 2007. Our commodity-based derivative contracts include options and swaps that we use to manage our natural gas and oil exposures and other natural gas and power purchase and supply contracts and derivatives related to our legacy energy trading activities. Interest rate and foreign currency derivatives consist of swaps that are primarily designated as accounting hedges of our interest rate and foreign currency risk on long-term debt.

	As of December 31,	
	2008	2007
	(In millions)	
Net assets (liabilities):		
Derivatives designated as accounting hedges	$	$ (23)
Derivatives not designated as accounting hedges	(25)	(869)
Total commodity-based derivatives	(25)	(892)
Interest rate and foreign currency derivatives	85	109
Net liabilities from price risk management activities[1]	$ 60	$ (783)

[1] Included in both current and non-current assets and liabilities on the balance sheet.

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.

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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 option contracts to limit our exposure to decreases in commodity prices as well as fluctuations in foreign currency and interest rates with the objective of limiting the variability of the cash flows 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, 2008 and 2007 follows:

	Accumulated Other Comprehensive Income (Loss) 2008	Accumulated Other Comprehensive Income (Loss) 2007	Estimated Income (Loss) Reclassification in 2009[1]	Final Termination Year
		(In millions)		
Commodity cash flow hedges				
Held by consolidated entities	$	$ (25)	$	
De-designated	241		260	2012
Total commodity cash flow hedges	241	(25)	260	
Interest rate and foreign currency cash flow hedges				
Held by consolidated entities	(12)	(2)		2015
Held by unconsolidated affiliates	(13)	(4)		2013
De-designated	(3)	(4)		2009
Total interest rate and foreign currency cash flow hedges	(28)	(10)		
Total cash flow hedges	$ 213	$ (35)	$ 260	

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

For the years ended December 31, 2008, 2007 and 2006, we recognized a net gain of $1 million, a net loss of $3 million and a net gain of $10 million, net of income taxes, respectively, in our income (loss) from continuing operations related to the ineffective portion of our cash flow hedges.

During the fourth quarter of 2008, we removed the hedging designation on all of our commodity-based derivatives based on our decision to discontinue the use of hedge accounting prospectively for these derivatives. The accumulated other comprehensive income of $241 million, net of income taxes, associated with these derivatives will be reclassified into earnings as the original hedged transactions occur through 2012.

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, 2008 and 2007, these derivatives were as follows (amounts in millions):

Derivative	Weighted Average Rate	Hedged Debt 2008	Hedged Debt 2007	Price Risk Management Asset (Liability)[1] 2008	Price Risk Management Asset (Liability)[1] 2007
Fixed-to-floating swaps	LIBOR + 4.18%	$ 218	$ 218	$ 12	$ (5)
Fixed-to-floating cross currency swaps[2]	LIBOR + 4.23%	379	379	94	118
				$ 106	$ 113

(1) We did not record any ineffectiveness related to our fair value hedges in 2008 or 2007.

(2) As of December 31, 2008 and 2007, these derivatives, when combined with our Euro denominated debt, converted 330 million Euro of our debt to $379 million.

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. 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.

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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, 2008 and 2007:

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2008				
Energy marketers	$ 247	$ 72	$	$ 319
Natural gas and electric utilities			30	30
Financial institutions and other	480		3	483
Net financial instrument assets	727	72	33	832
Collateral held by us		(62)	(30)	(92)
Net exposure from derivative assets	$ 727	$ 10	$ 3	$ 740

Counterparty	Investment Grade[1]	Below Investment Grade[1]	Not Rated[1]	Total
		(In millions)		
December 31, 2007				
Energy marketers	$ 30	$ 110	$	$ 140
Natural gas and electric utilities			71	71
Financial institutions and other	86			86
Net financial instrument assets	116	110	71	297
Collateral held by us		(100)	(47)	(147)
Net exposure from derivative assets	$ 116	$ 10	$ 24	$ 150

(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 does not meet the criteria of Investment Grade . Not Rated includes counterparties that are not rated by any public rating service.

We have approximately 26 counterparties as of December 31, 2008. 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, 2008, three counterparties, J Aron, Merrill Lynch, and Societe Generale comprise 30 percent, 37 percent and 12 percent, respectively of our net financial instrument exposure. As of December 31, 2007, four counterparties, Merrill Lynch Commodities, Morgan Stanley Group, Central Lomas de Real and Constellation Energy Commodities Group, Inc., comprised 20 percent, 16 percent, 15 percent and 12 percent, respectively 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.

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9. Regulatory Assets and Liabilities

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

	2008	2007
	(In millions)	
Current regulatory assets		
Deferred fuel loss and unaccounted for gas	$ 31	$
Other	8	
Total current regulatory assets	39	
Non-current regulatory assets		
Taxes on capitalized funds used during construction	137	122
Postretirement benefits	21	18
Unamortized net loss on reacquired debt	72	59
Other	22	22
Total non-current regulatory assets	252	221
Total regulatory assets	$ 291	$ 221
Current regulatory liabilities		
Over-collected fuel variance	$ 46	$ 19
Other	21	22
Total current regulatory liabilities	67	41
Non-current regulatory liabilities		
Environmental liability	157	143
Property and plant depreciation	60	74
Postretirement benefits	32	90
Plant regulatory liability	11	11
Other	3	10
Total non-current regulatory liabilities	263	328
Total regulatory liabilities	$ 330	$ 369

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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:

	2008	2007
	(In millions)	
Other current assets		
Prepaid expenses	$ 69	$ 66
Margin and other deposits held by others	5	27
Regulatory assets (Note 9)	39	
Other	35	34
Total	$ 148	$ 127
Other non-current assets		
Pension, other postretirement and postemployment benefits (Note 14)	$ 45	$ 660
Notes receivable from affiliates	240	220
Restricted cash (Note 1)	57	91
Unamortized debt expenses	112	107
Regulatory assets (Note 9)	252	221
Long-term receivables	50	116
Other	99	182
Total	$ 855	$ 1,597

	2008	2007
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 83	$ 89
Income taxes	4	47
Environmental, legal and rate reserves (Note 13)	131	174
Deposits	69	62
Pension and other postretirement benefits (Note 14)	46	28
Asset retirement obligations (Note 11)	83	41
Dividends payable	44	37
Regulatory liabilities (Note 9)	67	41
Other	132	134
Total	$ 659	$ 653
Other non-current liabilities		
Environmental and legal reserves (Note 13)	$ 161	$ 590
Pension, other postretirement and postemployment benefits (Note 14)	686	236
Regulatory liabilities (Note 9)	263	328
Asset retirement obligations (Note 11)	171	212
Other deferred credits	56	62
Insurance reserves	84	111

Other	258	211
Total	$ 1,679	$ 1,750

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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 transmission systems	Composite	(1)
Non-regulated assets		
Natural gas and oil properties	(2)	(2)
Transmission and storage facilities	Straight-line	15-25
Gathering and processing systems	Straight-line	15-40
Transportation equipment	Straight-line	5
Buildings and improvements	Straight-line	3-48
Office and miscellaneous equipment	Straight-line	1-10

(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 or impaired. See Note 1 for additional information.

Excess purchase costs. As of December 31, 2008 and 2007, TGP and EPNG have excess purchase costs associated with their historical acquisition. Total excess costs on these pipelines were approximately $2.5 billion and accumulated depreciation was approximately $0.5 billion and $0.4 billion at December 31, 2008 and 2007. These excess costs are being depreciated over the estimated life of the pipeline assets to which the costs were assigned, and our related depreciation expense for each year ended December 31, 2008, 2007, and 2006 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 costs capitalized are included as a reduction of interest expense in our income statements and were $45 million, $50 million and $41 million during the years ended December 31, 2008, 2007 and 2006. 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 $37 million, $32 million and $20 million during the years ended December 31, 2008, 2007 and 2006.

Construction work-in progress. At December 31, 2008 and 2007, we had approximately $2.6 billion and $1.6 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, natural gas pipelines, transmission facilities and storage wells, and obligations related to our corporate headquarters building. In our production operations, we have obligations to plug wells when abandoned because production is exhausted or we no longer plan to use the wells. In our pipeline operations, our legal obligations primarily involve 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 ever demolished, replaced or renovated. We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record.

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Where we can reasonably estimate the asset retirement obligation liability, we accrue a liability based on an estimate of the timing and amount of their settlement. In estimating the fair value of the liabilities associated with our asset retirement obligations, we utilize several assumptions, including a projected inflation rate of 2.5 percent, and credit-adjusted discount rates that currently range from 6 to 12 percent based on when the liabilities were recorded. We record changes in these estimates based on the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes 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 and from certain other events that accelerate the timing of asset retirements (e.g. the impact of hurricanes on our Exploration and Production segment and Pipelines segment). In our pipelines operations, we intend on operating and maintaining our natural gas pipeline and storage systems as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the asset retirement obligation liability for the substantial majority of our natural gas pipeline and storage system assets because these assets have indeterminate lives.

Our asset retirement liabilities as of December 31, 2008 reflect a reduction of approximately $109 million related to the 2008 sale of a portion of our natural gas and oil properties in the Gulf of Mexico and Texas Gulf Coast regions and an increase of approximately $62 million resulting from the 2008 impacts of Hurricanes Ike and Gustav on our exploration and production and pipeline assets, which is reflected as a change in estimate in the table below. 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:

	2008	**2007**
	(In millions)	
Net asset retirement liability at January 1	$ 253	$ 243
Liabilities settled	(120)	(62)
Accretion expense	16	23
Liabilities incurred	31	16
Changes in estimate	74	33
Net asset retirement liability at December 31	$ 254	$ 253

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12. Debt, Other Financing Obligations and Other Credit Facilities

	Year Ended December 31, 2008	2007
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,090	$ 331
Long-term financing obligations	12,818	12,483
Total	$ 13,908	$ 12,814

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

	Year Ended December 31, 2008	2007
	(In millions)	
Colorado Interstate Gas Company (CIG)		
Notes and debentures, 5.95% through 6.85%, due 2015 through 2037	$ 475	$ 575
El Paso Corporation		
Notes, 6.375% through 12%, due 2009 through 2037	6,936	6,090
$1.5 billion revolver, variable due 2012	522	425
El Paso Natural Gas Company (EPNG)		
Notes, 5.95% through 8.625%, due 2010 through 2032	1,169	1,169
El Paso Exploration & Production Company (EPEP)		
Senior note, 7.75%, due 2013	1	1
Revolving credit facility, variable due 2012	914	750
El Paso Pipeline Partners, L.P. (EPB)		
Revolving credit facility, variable due 2012	585	455
Notes, 7.76% through 8.00%, due 2011 through 2013	140	
Notes, variable due 2012	35	
Southern Natural Gas Company (SNG)		
Notes, 5.9% through 8.0%, due 2017 through 2032	911	1,134
Tennessee Gas Pipeline Company(TGP)		
Notes, 6.0% through 8.375%, due 2011 through 2037	1,626	1,626
Other	252	289
	13,566	12,514
Other financing obligations		
Capital Trust I, due 2028	325	325
Other	116	8
Subtotal	14,007	12,847
Less:		
Other, including unamortized discounts and premiums	99	33
Current maturities	1,090	331
Total long-term financing obligations, less current maturities	$ 12,818	$ 12,483

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Changes in Long-Term Financing Obligations. During 2008, we had the following changes in our long-term financing obligations (in millions):

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received / (Paid) [2]
Issuances			
El Paso			
Revolving Credit Facilities	variable	$ 2,697	$ 2,697
Notes due 2018	7.250%	600	595
Notes due 2013[1]	12.000%	445	438
EPEP Revolving Credit Facility	variable	549	549
El Paso Pipeline Partners, L.P.			
Revolving Credit Facility	variable	188	188
Private Placement Notes	various	175	174
Increases through December 31, 2008		$ 4,654	$ 4,641
Repayments, repurchases and other			
El Paso			
Revolving Credit Facilities	variable	$ (2,600)	$ (2,600)
Notes	6.625% to 7.625%	(258)	(258)
EPEP Revolving Credit Facility	variable	(385)	(385)
EPB Revolving Credit Facility	variable	(58)	(58)
CIG	5.950% to 6.800%	(100)	(103)
SNG	6.125% to 8.000%	(223)	(236)
Other	various	64	(39)
Decreases through December 31, 2008		$ (3,560)	$ (3,679)

(1) Principal amount of the note is $500 million.

(2) Amounts presented are net of associated underwriting discounts and expenses.

During the first two months of 2009, (i) TGP, our subsidiary, issued $250 million of 8.00% senior notes for net proceeds of approximately $235 million and (ii) we issued $500 million of 8.25% senior notes for net proceeds of approximately $473 million. Both the TGP and El Paso notes mature in February 2016. Additionally, our subsidiary that owns our Elba Island LNG facility issued $135 million of debt consisting of $71 million of five-year notes and $64 million of seven-year notes with a weighted average cost of 9.6%.

Debt Maturities. Aggregate maturities of the principal amounts of long-term financing obligations as of December 31, 2008 for the next 5 years and in total thereafter are as follows (in millions):

2009	$ 1,090(1)
2010	255
2011	683
2012	2,531
2013	611
Thereafter	8,837
Total long-term financing obligations, including current maturities	$ 14,007

(1) This amount does not include the fair value of our fixed-to-floating cross currency derivative assets of $94 million.

Credit Facilities/Letters of Credit

As of December 31, 2008, subject to the terms of various agreements, we had available capacity under credit agreements (not including capacity available under EPB s $750 million revolving credit facility) of approximately $1.2 billion. As part of our determination of available capacity under our credit agreements, we completed an assessment of the available lenders under our credit facilities. Based on our assessment, our available capacity noted previously was reduced to reflect the potential exposure to a loss of available capacity of approximately $28 million on El Paso s $1.5 billion revolving credit facility and approximately $2 million on EPEP s $1.0 billion revolving credit facility. Our assessment of the available lenders also reduced EPB s available capacity by approximately $15 million. This assessment is based upon the fact that one of our lenders has failed to fund previous requests under these facilities and has filed for bankruptcy. Below is a description of our existing credit facilities as of December 31, 2008:

$1.5 Billion Revolving Credit Agreement. We have a $1.5 billion revolving credit facility that matures in November 2012. El Paso and certain of its subsidiaries have guaranteed the $1.5 billion revolving credit agreement, which is collateralized by our stock ownership in EPNG and TGP who are also eligible borrowers under the $1.5 billion revolving credit agreement.

Under the $1.5 billion revolving credit facility, we can borrow funds at LIBOR plus 1.25% based on a current applicable margin or issue letters of credit at 1.375% of the amount issued. We pay an annual commitment fee of 0.25% (based on a current applicable margin) on any unused capacity under the revolving credit facility. Under the credit agreement, the applicable margin used to calculate interest on borrowings, letters of credit and commitment fees is determined by a variable pricing grid tied to the credit ratings of our senior secured debt. As of December 31, 2008, we had approximately $0.2 billion of letters of credit issued and $0.5 billion of debt outstanding under this facility. As of December 31, 2008, our remaining capacity under the facility is approximately $0.7 billion.

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 2.34% 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. Substantially all of the capacity under this facility was used to issue letters of credit. As of December 31, 2008, our remaining capacity under this facility is approximately $53 million.

Unsecured Credit Facilities. We have a $500 million unsecured facility that provides for both borrowings and issuing letters of credit. The facility matures in various tranches during 2009. Based on this facility size, we are required to pay a fixed facility fee at a weighted average rate of 1.58% per annum on the full facility amount. Borrowings carry an interest rate of LIBOR in addition to the facility fee. Substantially all of the capacity under this facility was used to issue letters of credit and approximately $54 million was available under this facility at December 31, 2008.

Through February 2009, we have entered into a similar $100 million facility that matures in various tranches beginning in 2013 and into 2014 with a weighted average fixed facility fee of 7.91%.

EPEP $1.0 Billion Revolving Credit Agreement. As of December 31, 2008, we had $0.9 billion outstanding under EPEP s $1.0 billion revolving credit facility and $0.1 billion of available capacity. Based on current borrowing levels, we pay interest at LIBOR plus 1.75% on borrowings, and a commitment fee of 0.375% on any unused capacity. This facility is collateralized by certain of our natural gas and oil properties, which are subject to revaluation on a semi-annual basis. As of December 31, 2008, the most recent determination was sufficient to fully support this facility. This facility matures in 2012.

EPEP $300 Million Revolving Credit Agreement. As of December 31, 2008, we had $300 million of available capacity under EPEP s new $300 million 364-day secured revolving credit facility that matures in December 2009. We pay LIBOR plus 3.5% for borrowed money, and a 1.00% commitment fee. This facility is collateralized by certain of our natural gas and oil properties.

EPB s $750 Million Revolving Credit Facility. In 2007, EPB and WIC (EPB s subsidiary) entered into an unsecured 5-year revolving credit facility with an initial aggregate borrowing capacity of up to $750 million expandable to $1.25 billion for certain expansion projects and acquisitions. This facility is only available to EPB and its subsidiaries and borrowings are guaranteed by EPB or its subsidiaries. Amounts borrowed are non-recourse to El Paso. Approximately $585 million was outstanding under the credit facility and EPB had remaining capacity of approximately $150 million as of December 31, 2008. The credit facility has two pricing grids, one based on credit ratings and the other based on leverage. Currently, the leverage pricing grid is in effect and EPB s cost of borrowings is LIBOR plus 0.425% based on EPB s current leverage. EPB also pays a 0.125% facility fee and a 0.10% commitment utilization fee annually for this facility.

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. During 2008, we entered into a new letter of credit facility with a bank to support our purchase commitments for pipe related to the Ruby Pipeline project. We have issued two letters of credit under this facility that total approximately $450 million. Of our outstanding letters of credit under this facility, we pay 0.85% annually on approximately $180 million maturing in one year and 1.00% annually on approximately $270 million maturing in two years. As of December 31, 2008, we had total outstanding letters of credit issued under all of our facilities of approximately $1.6 billion. Included in this amount is $0.8 billion of letters of credit securing our recorded obligations related to price risk management activities.

Restrictive Covenants

$1.5 Billion Revolving Credit Agreement. Our covenants under the $1.5 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 5.25 to 1 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 2.00 to 1 until maturity;

(c) EPNG and TGP 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 $1.0 Billion and $300 Million Revolving Credit Agreements. EPEP s borrowings under these facilities are subject to various conditions. The financial coverage ratio under both facilities requires that EPEP s EBITDA, as defined in the facility, to interest expense not be less than 2.0 to 1 and EPEP s debt to EBITDA, each as defined in the credit agreement, must not exceed 4.0 to 1.

EPB s $750 Million Revolving Credit Facility. The facility requires that EPB maintain, as of the end of each fiscal quarter, a consolidated leverage ratio, as defined in the facility, of less than 5.0 to 1 for any four consecutive quarters, and 5.5 to 1 for any three consecutive quarters subsequent to the consummation of specified permitted acquisitions having a value of greater than $25 million.

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 incurrence of liens; potential limitations on the ability 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. Our most restrictive cross-acceleration provision 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 of that subsidiary in excess of $10 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.

WYCO. In November 2008, the High Plains pipeline was placed in service. We constructed the pipeline and our joint venture partner (an affiliate of Public Service Company of Colorado (PSCo)) in WYCO funded 50 percent of the pipeline construction costs, which we reflected as an other non-current liability in our balance sheet during the construction period. Upon completion of the construction, our obligation to the affiliate of PSCo for these construction advances was converted into a financing obligation to WYCO and, accordingly we reclassified the amounts from other non-current liabilities to debt and other financing obligations during the fourth quarter of 2008. The principal amount of this obligation was $108 million as of December 31, 2008, which will be paid in monthly installments through 2043.

Non-Recourse Project Financings. Several of our subsidiaries and investments have debt obligations related to their costs of construction or acquisition. This project financing debt is recourse only to the project company and assets (i.e. without recourse to El Paso). As of December 31, 2008, one international power project accounted for as an equity investment is in default under its debt agreement; however, we have no material exposure as a result of this default.

13. Commitments and Contingencies

Legal Proceedings

ERISA Class Action Suit. 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 various misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). We have insurance coverage for this lawsuit, subject to certain deductibles and co-pay obligations. We have executed agreements to settle this matter. The settlement is subject to the approval of the court. We have established accruals for this matter 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. The trial court has dismissed the Plaintiffs claims. The Plaintiffs have filed a motion seeking to overturn the dismissal of the case. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. In 2002, a lawsuit entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation* was filed in a federal court in Detroit, Michigan. The lawsuit was filed on behalf of a group of retirees of Case Corporation (Case) that alleged they are entitled to retiree medical benefits under a medical benefits plan for which we serve as plan administrator pursuant to a merger agreement with Tenneco Inc. Although we had asserted that our obligations under the plan were subject to a cap pursuant to an agreement with the union for Case employees, in the first quarter of 2008, the trial court granted a summary judgment and ruled that the benefits were vested and not subject to the cap. As a result, we were obligated to pay the amounts above the cap and we adjusted our existing indemnification accrual using current actuarial assumptions and reclassified our liability as a postretirement benefit obligation. See Note 14 for a discussion of the impact of this matter. We intend to pursue appellate options following the determination by the trial court of any damages incurred by the plaintiffs during the period when premium payments above the cap were paid by the retirees. We believe our accruals established for this matter are adequate.

Price Reporting Litigation. Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that 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 set of cases, involving similar allegations on behalf of commercial and residential customers, was transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada and styled *In re: Western States Wholesale Natural Gas Antitrust Litigation*. These cases were dismissed. The U.S. Court of Appeals for the Ninth Circuit, however, reversed the dismissal and ordered that these cases be remanded to the trial court. The second set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include *Farmland Industries v. Oneok Inc., et al.* (filed in state court in Wyandotte County, Kansas in July 2005) and *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 the 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., et al. v. AEP Energy Services Inc., et al.* (filed in federal court for the Eastern District of California in September 2005); *Learjet, Inc., et al. v. Oneok Inc., et al.* (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); *Arandell, et al. v. Xcel Energy, et al.* (filed in the circuit court of Dane County, Wisconsin in December 2006); and *Heartland, et al. v. Oneok Inc., et al.* (filed in the circuit court of Buchanan County, Missouri in March 2007). The *Leggett* case was dismissed by the Tennessee state court, but in October 2008, the Tennessee Court of Appeals reversed the dismissal, remanding the matter to the trial court. The decision has been appealed to the Tennessee Supreme Court. The *Missouri Public Service* case was transferred to the MDL, but remanded back to state court, where a motion to dismiss has been granted. The dismissal has been appealed. The remaining cases have all been transferred to the MDL proceeding. The *Breckenridge Case* has been dismissed as to El Paso and other Defendants, and a motion for reconsideration of this decision was denied. This ruling can still be appealed. Discovery is proceeding in the MDL cases. We reached an agreement in principle to settle the *Western States* and *Ever-Bloom* cases and have established accruals for those cases which we believe are adequate. Settlement documents are being drafted. Our costs and legal exposure related to the remaining 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 and have 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 October 2006, the U.S. District Judge issued an order dismissing all 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 claims are not currently determinable.

MTBE. Certain of our subsidiaries used, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies. They have sought different remedies, including remedial activities, damages, attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. We recently settled 59 of these lawsuits, with our payments being made in October 2008. These payments were covered by insurance and all of the payments have been funded by our insurers. Following such settlements, there are 27 lawsuits that remain. While the damages claimed in the remaining actions are substantial, there remains significant legal uncertainty regarding the validity of the causes of action asserted and the availability of the relief sought. We have or will tender these remaining cases to our insurers. It is likely that our insurers will assert denial of coverage on the six most-recently filed cases. Our costs and legal exposure related to these remaining 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 originally self-reported this matter to the SEC and cooperated with the SEC in its investigation. On July 10, 2008, the SEC approved a settlement entered into by El Paso and two of its subsidiaries, El Paso Exploration and Production and El Paso CGP (which was formerly known as The Coastal Corporation), that fully resolves the previously disclosed SEC s investigation of our oil and gas reserve estimates for periods prior to 2004. Pursuant to the terms of the settlement, no monetary fine or penalty has been imposed upon the companies and, without admitting or denying any wrongdoing, the companies consented to the entry of a cease and desist order with respect to various provisions of the Securities Act of 1933, the Securities Exchange Act of 1934 and related SEC rules.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims 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 these matters, we evaluate the merits of the case or claim, 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. It is possible, however, 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, 2008, we had approximately $87 million accrued, which has not been reduced by $14 million of related insurance receivables, for our outstanding legal and governmental proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In June 2008, EPNG filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposed an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates to be effective January 1, 2009, subject to refund and the outcome of a hearing and a technical conference. The FERC issued an order in December 2008 that generally accepted most of EPNG s proposals in the technical conference proceeding. The FERC appointed an administrative law judge who will decide the remaining issues should EPNG be unable to reach a settlement with its customers in upcoming negotiations.

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Notice of Proposed Rulemaking. On October 3, 2007, the Minerals Management Service (MMS) issued a Notice of Proposed Rulemaking for Oil and Gas and Sulphur Operations in the Outer Continental Shelf (OCS) Pipelines and Pipeline Rights-of-Way. If adopted, the proposed rules would substantially revise MMS OCS pipeline and rights-of-way regulations. The proposed rules would have the effect of: (1) increasing the financial obligations of entities, like us, which have pipelines and pipeline rights-of-way in the OCS; (2) increasing the regulatory requirements imposed on the operation and maintenance of existing pipelines and rights-of-way in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS.

Other Matter

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 (BIA). Subject to final reviews and approvals by the Navajo Nation, EPNG has reached an agreement in principle on the terms of tribal consent to BIA s right-of-way grant through 2025. EPNG made a payment to the Navajo Nation in October 2008 covering a twelve-month period through October 2009 and will continue to make annual payments per the terms of the definitive agreement. We have filed with the FERC for recovery of these amounts in our recent rate case.

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. At December 31, 2008, we had accrued approximately $204 million for environmental matters, which has not been reduced by $22 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $198 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $6 million for related environmental legal costs. Of the $204 million accrual, $17 million was reserved for facilities we currently operate and $187 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $204 million to approximately $388 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 ($12 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($192 million to $376 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, 2008	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 17	$ 23
Non-operating	168	321
Superfund	19	44
Total	$ 204	$ 388

Below is a reconciliation of our accrued liability from January 1, 2008 to December 31, 2008 (in millions):

Balance as of January 1, 2008	$ 260
Additions/adjustments for remediation activities	(11)
Payments for remediation activities	(44)
Other changes, net	(1)
Balance as of December 31, 2008	$ 204

CERCLA Matters. As part of our environmental remediation projects, 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 33 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements, which provide for payment of our allocable share of remediation costs. 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.

For 2009, we estimate that our total remediation expenditures will be approximately $67 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 $9 million in the aggregate for the years 2009 through 2013. These expenditures primarily relate to compliance with clean air regulations.

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.

Greenhouse Gas (GHG) Emissions. Legislative and regulatory measures to address GHG emissions are in various phases of discussions or implementation at the international, national, regional and state levels. These measures include the Kyoto Protocol, which has been ratified by some of the international countries in which we have operations such as Mexico, Brazil, and Egypt. In the United States, it is likely that federal legislation requiring GHG controls will be enacted in the next few years. In addition, the EPA is considering initiating a rulemaking to regulate GHGs under the Clean Air Act. Legislation and regulation are also in various stages of discussions or implementation in many of the states in which we operate. These measures include recommendations released by the Western Climate Initiative regarding a cap-and-trade program and targeted emission reductions in several states in which we operate in the western United States, as well as recent legislation enacted in California that imposes GHG emission reduction targets. Additionally, lawsuits have been filed seeking to force the federal government to regulate GHG emissions and individual companies to reduce GHG emissions from their operations. These and other lawsuits may result in decisions by state and federal courts and agencies that could impact our operations and ability to obtain certifications and permits to construct future projects. Our costs and legal exposure related to GHG regulations are not currently determinable.

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 equipment. The terms of the agreements vary from 2009 until 2053. Future minimum annual rental commitments under our operating leases net of minimum sublease rentals at December 31, 2008, were as follows:

Year Ending December 31,	**Operating Leases (In millions)**
2009	$ 15
2010	10
2011	8
2012	7
2013	6
Thereafter	24
Total	$ 70

Rental expense on our lease obligations for the years ended December 31, 2008, 2007, and 2006 was $39 million, $40 million and $43 million.

Guarantees and Indemnifications. We are involved in various joint ventures and other ownership arrangements that sometimes require 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, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $797 million, which primarily relates to indemnification arrangements associated with the sale of ANR, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 12. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. We are unable to estimate a maximum exposure of our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of December 31, 2008, we have recorded obligations of $62 million related to our indemnification arrangements. This liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its estimated fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification. We believe that our guarantee and indemnification agreements for which we have not recorded a liability are not probable of resulting in future losses based on our assessment of the nature of the guarantee, the financial condition of the guaranteed party and the period of time that the guarantee has been outstanding, among other considerations.

Purchase Obligations. During 2008, we entered into contracts to purchase pipe primarily associated with the Ruby Pipeline project and TGP s 300 Line expansion which are anticipated to be placed in service between 2010 and 2011. Our estimated obligations under these agreements are approximately $816 million in 2009, $837 million in 2010 and $105 million in 2011.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2008, we had firm commitments under transportation and storage capacity contracts of $295 million due at various times and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of approximately $392 million, the substantial majority of which is due in less than one year.

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, Inc. or The Coastal Corporation receive the greater of cash balance benefits or transition benefits under the prior plan formulas. Prior to December 31, 2008, we maintained two other frozen pension plans which provide benefits to former employees of our previously discontinued coal and convenience store operations. Effective December 31, 2008, these frozen plans were merged with our cash balance plan. We do not anticipate making any contributions to our cash balance pension plan in 2009.

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 expect to contribute $4 million to the SERP in 2009.

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 six percent of eligible compensation and can make additional discretionary matching contributions depending on our performance relative to our peers. Amounts expensed under this plan were approximately $20 million, $16 million and $30 million for the years ended December 31, 2008, 2007 and 2006.

Other Postretirement Benefits. We provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees and limited postretirement life insurance benefits for current and retired employees. 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. OPEB for our regulated pipeline companies are prefunded to the extent such costs are recoverable through rates. To the extent 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 $50 million to our other postretirement benefit plans in 2009.

Other Matters. In various court rulings prior to March 2008, we were required to indemnify Case Corporation for certain benefits paid to a closed group of Case retirees as further discussed in Note 13. In conjunction with those rulings, we recorded a liability for estimated amounts due under the indemnification using actuarial methods similar to those used in estimating our postretirement benefit plan obligations. This liability, however, was not included in our postretirement benefit obligations or disclosures in 2007.

In the first quarter of 2008, we received a summary judgment from the trial court on this matter, and thus became the primary party that is obligated to pay for these benefit payments. As a result of the judgment, we adjusted our obligation using current actuarial assumptions, recording a $65 million reduction to current and non-current other liabilities and to operation and maintenance expense. We also reclassified this obligation from an indemnification liability to a postretirement benefit obligation, which increased our overall postretirement benefit obligations by $280 million.

Pension and Other Postretirement Benefits

Effective December 31, 2006, we began accounting for our pension and other postretirement benefit plans under the recognition provisions of SFAS No. 158. Under SFAS No. 158, we record an asset or liability for our pension and other postretirement benefit plans based on their over funded or under funded status. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded either as a regulatory asset or liability for our regulated operations or in accumulated other comprehensive income (loss), a component of stockholders equity, for our nonregulated operations until those gains and losses are recognized in the income statement.

Effective January 1, 2008, we adopted the measurement date provisions of SFAS No. 158 and changed the measurement date of our pension and other postretirement benefit plans from September 30 to December 31. We recorded a $4 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated deficit and a $3 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated other comprehensive loss upon the adoption of the measurement date provisions of this standard to reflect an additional three months of net periodic benefit cost based on our September 30, 2007 measurement.

Benefit Obligation,Plan Assets and Funded Status. The table below provides information about our pension and other postretirement benefit (OPEB) plans. In 2008, we adopted the measurement date provisions for SFAS No. 158 and the information below for 2008 is presented and computed as of and for the fifteen months ended December 31, 2008. For 2007, the information is presented and computed as of and for the twelve months ended September 30, 2007.

	December 31, 2008		**September 30, 2007**	
	Pension	**OPEB**	**Pension**	**OPEB**
	(In millions)			
Change in benefit obligation:(1)				
Benefit obligation beginning of period	$ 2,027	$ 418	$ 2,157	$ 494
Service cost	18		17	1
Interest cost	150	44	119	26
Participant contributions		13		32
Actuarial gain	(12)	(12)	(86)	(66)
Benefits paid(2)	(209)	(72)	(186)	(69)
Case liability reclassification		282		
Other	15		6	
Benefit obligation end of period	$ 1,989	$ 673	$ 2,027	$ 418

Change in plan assets:				
Fair value of plan assets beginning of period	$ 2,537	$ 303	$ 2,382	$ 276
Actual return on plan assets[3]	(561)	(67)	333	39
Employer contributions	6	39	8	25
Participant contributions		13		32
Benefits paid	(209)	(78)	(186)	(69)
Fair value of plan assets end of period	$ 1,773	$ 210	$ 2,537	$ 303
Reconciliation of funded status:				
Fair value of plan assets	$ 1,773	$ 210	$ 2,537	$ 303
Less: Benefit obligation	1,989	673	2,027	418
Fourth quarter contributions			3	5
Net asset (liability) at December 31	$ (216)	$ (463)	$ 513	$ (110)

(1) The benefit obligation for our pension plans represents the projected benefit obligation and the benefit obligation for our other postretirement benefit plans represents the accumulated postretirement benefit obligation.

(2) Amounts for other postretirement benefits are shown net of a subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

(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 amortized only to the extent that our remaining unrecognized actual gains and losses exceed the greater of 10 percent of our benefit obligations or market related value of plan assets.

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The following table details the amounts recognized in our balance sheet at December 31, 2008 and 2007 related to our pension and other postretirement benefit plans.

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
	(In millions)			
Current benefit liability	$ 4	$ 4	$ 42	$ 24
Non-current benefit liability	212	33	463	192
Non-current benefit asset		550	42	106
Accumulated other comprehensive income (loss), net of income taxes	(770)	(269)	25	32

Our accumulated other comprehensive loss at December 31, 2008 includes approximately $4 million of unamortized prior service costs, net of tax. We anticipate that approximately $27 million of our accumulated other comprehensive loss, net of tax, will be recognized as a part of our net periodic benefit cost in 2009.

Our accumulated benefit obligation for our defined benefit pension plans was $2.0 billion at December 31, 2008 and 2007. Our accumulated benefit obligation for our defined benefit pension plans, whose accumulated benefit obligations exceeded the fair value of plan assets, was $2.0 billion and $37 million as of December 31, 2008 and 2007.

Our accumulated postretirement benefit obligation for our other postretirement benefit plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $552 million and $222 million as of December 31, 2008 and 2007.

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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 exists to meet the benefit obligations to participants, retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions. As a result of the general decline in the markets for debt and equity securities the fair value of our plans assets and the funded status of our pension and other postretirement benefit plans declined significantly during 2008 which resulted in a significant decrease in our pension assets and other comprehensive income when our plans assets and obligations were remeasured at December 31, 2008. We do not expect to make any contributions to our cash balance pension plan in 2009. The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of December 31, 2008 and September 30, 2007:

	Pension Plans			**Other Postretirement Plans**		
Asset Category	**Target**	**Actual 2008[1]**	**Actual 2007**	**Target**	**Actual 2008**	**Actual 2007**
		(Percent)			**(Percent)**	
Equity securities	60	48	67	65	64	63
Debt securities	40	50	32	35	34	33
Other		2	1		2	4
Total	100	100	100	100	100	100

(1) Actual allocations are different than target due to market declines discussed above.

Expected Payment of Future Benefits. As of December 31, 2008, we expect the following payments under our plans:

Year Ending December 31,	**Pension Benefits**	**Other Postretirement Benefits[1]**
	(In millions)	
2009	$182	$ 61
2010	183	61
2011	179	61
2012	179	60
2013	181	60
2014-2018	874	276

(1) Includes a reduction in each of the years presented for participant

contributions and an expected subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

Actuarial Assumptions and Sensitivity Analysis. 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 benefit obligation and net benefit costs of our pension and other postretirement plans for 2008, 2007 and 2006:

	Pension Benefits			Other Postretirement Benefits		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
		(Percent)			**(Percent)**	
Assumptions related to benefit obligations at December 31, 2008 and September 30, 2007 and 2006 measurement dates:						
Discount rate	6.33	6.25	5.75	5.98	6.05	5.50
Rate of compensation increase	4.18	4.27	4.00			
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.25	5.75	5.50	6.05	5.50	5.25
Expected return on plan assets[1]	8.00	8.00	8.00	8.00	8.00	8.00
Rate of compensation increase	4.27	4.00	4.00			

[1] The expected return on plan assets is a pre-tax rate of return based on our targeted portfolio of investments. Some of our postretirement benefit plans investment earnings are subject to unrelated business income

tax at a rate of 35%. The expected return on plan assets for our postretirement benefit plans is calculated using the after-tax rate of return.

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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 8.6 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 December 31, 2008 and 2007:

	2008	2007
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 2	$ 1
Accumulated postretirement benefit obligation	48	13
One percentage point decrease: Aggregate of service cost and interest cost	$ (2)	$ (1)
Accumulated postretirement benefit obligation	(44)	(12)

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

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
	(In millions)					
Service cost	$ 15	$ 17	$ 17	$	$ 1	$ 11
Interest cost	120	119	118	38	26	26
Expected return on plan assets	(187)	(181)	(175)	(17)	(16)	(14)
Amortization of net actuarial (gain) loss	24	43	55	(5)	(1)	
Amortization of prior service credit[1]	(2)	(2)	(2)	(1)	(1)	(1)
Other			(2)			(1)
Net benefit cost (income)	$ (30)	$ (4)	$ 11	$ 15	$ 9	$ 21

(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, or in the case of retired

participants,
over the average
remaining life.

15. Stockholders Equity

Share Repurchase Program. During 2008, the Board approved a $300 million share repurchase program and we repurchased approximately $77 million in common stock under the program. The program has no stated expiration date.

Convertible Perpetual Preferred Stock. In 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 76.9367 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately $13.00 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 payment of dividends on our common stock in excess of a specified rate. We will be able to cause the preferred stock to be converted into common stock five years after issuance if our common stock is trading at a premium of 130 percent to the conversion price.

Common and Preferred Stock Dividends. The table below shows the amount of dividends paid and declared (dollars in millions):

	Common Stock	Convertible Preferred Stock
Amount paid in 2008	$ 120	$ 37
Amount paid in January 2009	$ 34	$ 9
Declared in 2009:		
Date of declaration	February 10, 2009	February 10, 2009
Payable to shareholders on record	March 6, 2009	March 15, 2009
Date payable	April 1, 2009	April 1, 2009

Dividends on our common stock and preferred 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 2008 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. During 2008, our Board of Directors declared dividends for our common shareholders of $0.04 per share in February and March and $0.05 per share in July and October.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock provide for the conversion ratio on our preferred stock to increase when we pay quarterly dividends to our common shareholders in excess of $0.04 per share, as we did in October 2008 and January 2009. The terms of these preferred shares also 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 we are unable to comply with our fixed charge ratio, 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:

	2008	2007
Cash flow hedges (see Note 8)	$ 213	$ (35)
Pension and other postretirement benefits (see Note 14)	(745)	(237)
Total accumulated other comprehensive loss, net of income taxes	$ (532)	$ (272)

16. Stock-Based Compensation

Overview. 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 Omnibus plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At December 31, 2008, approximately 22 million shares remain available for grant under our current plans, which includes approximately 17.6 million shares under our Omnibus plan, 2 million shares under our non-employee director plan and 2.4 million shares under our employee stock purchase plan. We also have approximately 14 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.

We record stock-based compensation expense, excluding amounts capitalized, as operation and maintenance expense over the requisite service period 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.

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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, 2008 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, 2007	23,983,995	$31.93		
Granted	5,082,009	$16.64		
Exercised	(1,107,406)	$ 9.58		
Forfeited or canceled	(465,005)	$17.26		
Expired	(2,723,320)	$46.73		
Outstanding at December 31, 2008	24,770,273	$28.44	5.46	$ 1
Vested at December 31, 2008 or expected to vest in the future	24,326,671	$28.68	5.40	$ 1
Exercisable at December 31, 2008	15,898,229	$35.75	3.69	$ 1

In 2008, 2007 and 2006, we recognized $21 million, $16 million and $11 million of pre-tax compensation expense on stock options, capitalized approximately $4 million, $4 million and $2 million of this expense in each respective year as part of fixed assets and recorded $7 million, $6 million and $4 million of income tax benefits. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2008 was approximately $19 million, which is expected to be recognized over a weighted average period of 10 months. Options exercised during the year ended December 31, 2008, 2007 and 2006 had a total intrinsic value of approximately $10 million, $6 million and $5 million, generated $11 million, $7 million and $6 million of cash proceeds and did not generate any significant associated income tax benefit.

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, 2008, 2007 and 2006 the weighted average grant date fair value per share of options granted was $5.73, $5.53, and $4.89.

Listed below is the weighted average of each assumption based on grants in each fiscal year:

	2008	2007	2006
Expected Term in Years	6.0	6.0	6.0
Expected Volatility	35%	34%	38%
Expected Dividends	1%	1%	1.3%
Risk-Free Interest Rate	2.8%	4.6%	4.9%

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 (SAB) No. 107 and estimate the expected term of our option awards based on the vesting period and average remaining contractual term. We continue to use this approach for all stock option contracts consistent with SEC SAB No. 110, *Share Based Payment*, which allows us to continue the use of this simplified method in estimating our expected term consistent with the manner in which we determined expected term under SAB No. 107. We use this method to provide a reasonable basis for estimating our expected term based on a lack of sufficient historical data due to significant changes in the composition of our employees receiving stock-based compensation awards prior to 2006.

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. 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, 2007	3,915,940	$ 13.74
Granted	2,240,971	$ 15.46
Vested	(1,844,599)	$ 13.12
Forfeited	(213,970)	$ 14.76
Nonvested at December 31, 2008	4,098,342	$ 14.91

The weighted average grant date fair value per share for restricted stock granted during 2008, 2007 and 2006 was $15.46, $14.73 and $13.09. The total fair value of shares vested during 2008, 2007 and 2006 was $29 million, $31 million, and $24 million.

During 2008, 2007 and 2006, we recognized approximately $29 million, $25 million and $17 million of pre-tax compensation expense on our restricted share awards, capitalized approximately $7 million in 2008, $7 million in 2007 and $2 million in 2006 as part of fixed assets and recorded $10 million, $9 million and $6 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2008 was approximately $25 million, which is expected to be recognized over a weighted average period of 10 months.

Employee Stock Purchase Plan. Our employee stock purchase 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 2008, 2007 and 2006.

17. Business Segment Information

As of December 31, 2008, our business consists of two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate activities 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, 2008, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in four transmission systems. We also own or have interests in two underground natural gas storage facilities, and two LNG terminalling facilities, one of which is under construction.

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

Marketing. Markets and manages the price risks associated with our natural gas and oil production as well as manages our remaining legacy trading portfolio.

Power. Manages the risks associated with our remaining international power assets and investments located primarily in South America and Asia. We continue to pursue the sale of these assets.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2008, 2007 and 2006.

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Our management uses earnings before interest expense and income taxes (EBIT) as a measure to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to evaluate more effectively the 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 discontinued operations,(ii) interest and debt expense and (iii) income taxes. We exclude interest and debt expense 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 from continuing operations for the periods ended December 31:

	2008	2007	2006
		(In millions)	
Segment EBIT	$ (278)	$ 1,935	$ 1,838
Corporate and other	124	(283)	(88)
Interest and debt expense	(914)	(994)	(1,228)
Income taxes	245	(222)	9
Income (loss) from continuing operations	$ (823)	$ 436	$ 531

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, 2008					
	Segment					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
			(In millions)			
Revenue from external customers						
Domestic	$ 2,621	$ 1,317(2)	$ 1,137	$	$ 9	$ 5,084
Foreign	11	22(2)	237		9	279
Intersegment revenue	52	1,423(2)	(1,457)		(18)	
Operation and maintenance	863	404	19	15	(111)	1,190
Ceiling test charges		2,669				2,669
Depreciation, depletion and amortization	395	799		1	10	1,205
Earnings from unconsolidated affiliates	97	(93)		40	4	48
EBIT	1,273	(1,448)	(104)	1	124	(154)
Assets of continuing operations						
Domestic	14,917	5,821	444	5	1,489	22,676
Foreign[3]	204	321	21	412	34	992
Capital expenditures and investments in and	1,457	1,622		(16)	43	3,106

advances to unconsolidated affiliates, net[4]					
Total investments in unconsolidated affiliates	1,054	531	99	19	1,703

(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 $19 million.

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

portion of our production to third parties.

(3) Of total foreign assets, approximately $0.3 billion relates to property, plant and equipment, and approximately $0.5 billion relates to investments in and advances to unconsolidated affiliates.

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

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	As of or for the Year Ended December 31, 2007					
	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate[1] and Other	Total
	(In millions)					
Revenue from external customers						
Domestic	$ 2,429	$ 1,123(2)	$ 814	$	$ 54	$ 4,420
Foreign	11	17(2)	163		37	228
Intersegment revenue	54	1,160(2)	(1,196)		(18)	
Operation and maintenance	753	439	11	17	113	1,333
Depreciation, depletion and amortization	373	780	3	1	19	1,176
Earnings (losses) from unconsolidated affiliates	105	11		(15)		101
EBIT	1,265	909	(202)	(37)	(283) (5)	1,652
Discontinued operations, net of income taxes	674					674
Assets of continuing operations						
Domestic	13,764	7,404	506	5	1,482	23,161
Foreign[3]	175	625	31	526	61	1,418
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[4]	1,059	2,613		(34)	7	3,645
Total investments in unconsolidated affiliates	759	704		151		1,614

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating

segments. We recorded an intersegment revenue elimination of $19 million and an operation and maintenance expense elimination of $1 million, which is included in the Corporate column, to remove intersegment transactions.

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

(3) Of total foreign assets, approximately $0.6 billion relates to property, plan

and equipment, and approximately $0.6 billion relates to investments in and advances to unconsolidated affiliates.

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

(5) Includes debt extinguishment costs of $86 million related to refinancing EPEP s $1.2 billion notes. Also includes $77 million in other income related to the reversal of a liability related to a legacy crude oil marketing and trading business matter.

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	As of or for the Year Ended December 31, 2006					
	Segments					
	Pipelines	Exploration and Production	Marketing (In millions)	Power	Corporate[1] and Other	Total
Revenue from external customers						
Domestic	$ 2,331	$ 645(2)	$ 1,012	$ 4	$ 116	$ 4,108
Foreign	10	32(2)	131			173
Intersegment revenue	61	1,177(2)	(1,201)	2	(39)	
Operation and maintenance	743	410	28	57	99	1,337
Depreciation, depletion and amortization	370	645	4	2	26	1,047
Earnings (losses) 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	12,958	5,858	1,115		1,950	21,881
Foreign[4]	147	404	28	618	50	1,247
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 price risk management activities associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing a significant portion of our production to third parties.

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

(4) Approximately $0.4 billion of total foreign assets 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.

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. The earnings from unconsolidated affiliates reflected in our income statement include (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, 2008 and 2007, our investment balance exceeded the net equity in the underlying net assets of these investments by $481 million and $377 million due to these items. The majority 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 estimated proved natural gas and oil reserves of Four Star. The information below related to our unconsolidated affiliates includes (i) our net investment and earnings (losses) we recorded from these investments, (ii) summarized financial information of our proportionate share of these investments, and (iii) revenues and charges with our unconsolidated affiliates. 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		
	2008	2007	2008	2007	2008	2007	2006
	(Percent)		(In millions)		(In millions)		
Four Star[(1)]	49	49	$ 525	$ 698	$ (93)	$ 12	$ 10
Citrus	50	50	564	576	64	81	62
Gulf LNG[(2)]	50		279				
Bolivia to Brazil Pipeline	8	8	119	105	25	11	11
Gasoductos de Chihuahua	50	50	174	146	29	21	25
Manaus/Rio Negro[(3)]		100		56		(6)	17
Porto Velho[(4)]	50	50	(64)	(60)	1	(23)	2
Asian and Central American Investments[(5)]	various	various	13	26	6	(1)	(6)
Argentina to Chile Pipeline	22	22	27	21	7	6	5
Other	various	various	66	46	9		19
Total			$ 1,703	$ 1,614	$ 48	$ 101	$ 145

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $53 million during each of the years ended December 31, 2008 and 2007 and $54 million

for the year ended December 31, 2006.

(2) In February 2008, we acquired a 50 percent interest in Gulf LNG. See Note 2.

(3) We transferred ownership of these plants to the power purchaser in January 2008. Accordingly, we eliminated our equity investments in these entities and retained current assets of $80 million and current liabilities of $24 million in January 2008. For a further discussion, see *Matters that Could Impact Our Investments* below.

(4) As of December 31, 2008 and 2007, we had outstanding advances and receivables of $242 million and $335 million related to our investment in Porto Velho,

that are not included in the table above. In February 2009, we completed the sale of our investment in and receivables from Porto Velho. For a further discussion, see *Matters that Could Impact Our Investments* below.

(5) In the second quarter of 2008, we sold our interests in the Khulna and Tipitapa power facilities.

We received cash distributions and dividends from our unconsolidated affiliates of $182 million and $223 million for the years ended December 31, 2008 and 2007. Included in these amounts are returns of capital of $2 million and $34 million.

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Impairment charges and gains and losses on sales of equity investments are included in earnings (losses) from unconsolidated affiliates. During 2008, we impaired our investment in Four Star based on a decrease in its fair value that resulted from declining commodity prices. During 2007, we impaired our investments in Porto Velho, Manaus and Rio Negro based on an assessment of the value we would receive in a sale of those investments due to developments in the power markets in Brazil. These gains (losses) consisted of the following:

Investment or Group	2008	2007	2006
		(In millions)	
Four Star	$ (125)	$	$
Porto Velho[1]		(32)	
Manaus and Rio Negro		(15)	
Other	7	(3)	6
	$ (118)	$ (50)	$ 6

(1) Amount in 2007 does not include a $25 million impairment of our note receivable.

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,		
	2008	2007	2006
		(In millions)	
Operating results data:			
Operating revenues	$ 708	$ 872	$1,101
Operating expenses	331	528	741
Income from continuing operations.	220	211	174
Net income [1]	220	211	174
Financial position data:[2]			
Current assets	$ 320	$ 390	$ 441
Non-current assets	2,667	2,323	2,408
Short-term debt	141	41	82
Other current liabilities	789	328	321
Long-term debt	169	519	556
Other non-current liabilities	666	588	592
Equity in net assets	1,222	1,237	1,298

(1) Includes net income (loss) of $1 million, $(1) million and $20 million in 2008, 2007 and 2006, related to

our proportionate share of affiliates in which we hold greater than a 50 percent interest.

(2) Includes total assets of $6 million and $190 million as of December 31, 2008 and 2007 related to our proportionate share of affiliates in which we hold greater than a 50 percent interest.

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

	2008	2007	2006
		(In millions)	
Operating revenue[1]	$7	$7	$64
Cost of sales		5	3
Other income	1	4	6
Interest income[2]	3	1	46
Interest expense	3		

(1) Decrease in 2007 primarily due to the sale of investments in our Power segment.

(2) Decrease in 2007 primarily due to the impairment of our Porto Velho note receivable in 2007.

Accounts Receivable Sales Program. Several of our pipeline subsidiaries have 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* whose purpose is solely to invest in our pipeline receivables. As of December 31, 2008 and 2007, we sold approximately $174 million and $189 million, of receivables, received cash of approximately $82 million and $79 million, received subordinated beneficial interests of approximately $89 million and $107 million, and recognized a loss of approximately $3 million in both years. In conjunction with the sale, the QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $85 million and $80 million as of December 31, 2008 and 2007. We reflect the subordinated beneficial interest in receivables sold at their fair value on the date they are issued. These amounts (adjusted for subsequent collections) are recorded as accounts receivable from affiliates in our balance sheet. Our ability to recover our carrying value of our subordinated beneficial interests is based on the collectibility of the underlying receivables sold to the QSPE s. 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 years ended December 31, 2008 and 2007.

Matters that Could Impact Our Investments

Listed below are our significant remaining international power investments and assets as of December 31, 2008:

Porto Velho. As of December 31, 2008, we have an equity investment in and a note receivable from the Porto Velho project in Brazil totaling $178 million. In February 2009, we completed the sale of our interests in Porto Velho to our partner in the project for $100 million of cash and $78 million of notes receivable from the buyer. The buyer s ability to repay these notes is partially dependent upon the profitability of the Porto Velho facility, which may be adversely impacted by developments in the Brazilian power market. These developments include the potential interconnection of the facility to an integrated power grid in Brazil and the potential construction of new hydroelectric plants in northern Brazil that could impact the amount of power Porto Velho would be able to sell under its power purchase agreements. If these adverse developments in the Brazilian power market occur, the ability to recover amounts due under the notes receivable could be affected.

Manaus /Rio Negro. In January 2008, we transferred our ownership in the Manaus and Rio Negro facilities to the plants power purchaser as required by their power purchase agreements. As of December 31, 2008, we have approximately $49 million of Brazilian reais-denominated accounts receivable owed to us under the projects terminated power purchase agreements, which are guaranteed by the purchaser s parent. The purchaser has withheld payment of these receivables in light of their Brazilian reais-denominated claims of approximately $48 million related to plant maintenance the purchaser claims should have been performed at the plants prior to the transfer, inventory levels and other items. We are in the process of finalizing agreements with the purchaser that would settle these outstanding claims and allow us to recover our accounts receivable. If these agreements are not finalized and if the purchaser does not agree to payment of our receivables, we will initiate legal action against the purchaser to collect our receivables and defend against their claims, and ultimately we will seek legal action to enforce the parental guarantee related to our receivables. We have reviewed our obligations under the power purchase agreement in relation to the claims and have accrued an obligation for the uncontested claims. We believe the remaining contested claims are without merit. The ultimate resolution of each of these matters is unknown at this time, and adverse developments related to either our ability to collect amounts due to us or related to the dispute could require us to record additional losses in the future.

During the fourth quarter of 2008, the administrative level of the Brazilian tax courts issued a ruling against the Manaus and Rio Negro projects for $47 million of taxes allegedly due on capacity payments they received from the plants power purchaser from 1999 to 2001. Under the power purchase agreements, the plants power purchaser must reimburse the Manaus and Rio Negro projects for ICMS taxes on their capacity payments. We anticipate that when the settlement agreements described above are finalized, the power purchaser will confirm that they are responsible for any amounts related to this ruling and not the Manaus and Rio Negro projects.

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of December 31, 2008, our total investment and guarantees related to this pipeline project was approximately $131 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. During the second quarter of 2008, the Bolivian government took control of the majority owner of the Bolivian portion of the pipeline, but has taken no action with regard to our two percent interest in this portion of the pipeline. We continue to monitor and evaluate the potential commercial impact that these political events in Bolivia could have on our investment. 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, 2008, our total investment in this pipeline project was approximately $27 million. The government of Argentina has issued decrees significantly increasing export taxes on natural gas transported on the Argentina-to-Chile pipeline. We continue to monitor and evaluate, together with our partners, the potential impact that these events in Argentina could have on our investment. Discussions with a group of our partners regarding the sale of our interest in the pipeline to them have progressed and we expect to complete the sale in the first half of 2009.

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Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter, is summarized below.

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
	(In millions, except per common share amounts)				
2008					
Operating revenues	$1,269	$1,153	$ 1,598	$ 1,343	$5,363
Operating income (loss)	550	421	839	(2,040)	(230)
Earnings (losses) from unconsolidated Affiliates	37	52	52	(93)	48
Net income (loss)	219	191	445	(1,678)	(823)
Net income (loss) available to common stockholders	200	191	436	(1,687)	(860)
Basic earnings per common share					
Net income	0.29	0.27	0.63	(2.43)	(1.24)
Diluted earnings per common share					
Net income (loss)	0.29	0.25	0.58	(2.43)	(1.24)
2007					
Operating revenues	$1,022	$1,198	$ 1,166	$ 1,262	$4,648
Operating income	335	451	417	442	1,645
Earnings (losses) from unconsolidated affiliates	37	44	(6)	26	101
Income (loss) from continuing operations	(48)	169	155	160	436
Discontinued operations, net of income taxes	677	(3)			674
Net income	629	166	155	160	1,110
Net income available to common stockholders	620	156	146	151	1,073
Basic earnings per common share					
Income (loss) from continuing operations	(0.08)	0.23	0.21	0.22	0.57
Net income	0.89	0.23	0.21	0.22	1.54
Diluted earnings per common share					
Income (loss) from continuing operations	(0.08)	0.22	0.20	0.21	0.57
Net income	0.89	0.22	0.20	0.21	1.53

Below are unusual or infrequently occurring items, if any, in each of the respective quarters of 2008 and 2007:

December 31, 2008. Items include (i) a total of $2.7 billion in domestic and international ceiling test charges; (ii) $125 million impairment of our investment in Four Star and (iii) $201 million in mark-to-market gains related to changes in fair value of our exploration and production derivatives that were not designated as hedges.

September 30, 2008. Items include (i) $214 million in mark-to-market gains related to changes in fair value of our exploration and production derivatives that were not designated as hedges and (ii) $63 million in mark-to-market gains on our PJM power contracts.

June 30, 2008. Items include (i) $105 million in mark-to-market losses on our PJM power contracts and (ii) $75 million in mark-to-market losses related to changes in fair value of our exploration and production derivatives that are not designated as hedges.

March 31, 2008. Items include $43 million in mark-to-market losses associated with the sale of a legacy ammonia facility.

September 30, 2007. Items include (i) $77 million gain in other income related to the reversal of a liability related to a legacy crude oil marketing and trading business matter and (ii) losses of $64 million ($72 million for the year ended December 31, 2007) related to our Porto Velho and Manaus and Rio Negro projects.

June 30, 2007. Items include (i) $86 million loss on debt extinguishment relating to repurchasing notes of El Paso Exploration and Production Company and (ii) a $35 million loss ($100 million for the year ended December 31, 2007) on our PJM power contracts, primarily resulting from increases in installed capacity prices.

March 31, 2007. Items include (i) gain of $651 million, net of taxes of $356 million on the sale of ANR and related assets recorded in discontinued operations and (ii) a loss on extinguishment of debt of $201 million in conjunction with the repurchase of $3.5 billion of debt obligations.

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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
2008			
Natural gas and oil properties:			
Costs subject to amortization	$ 18,503	$ 823	$ 19,326
Costs not subject to amortization	326	187	513
	18,829	1,010	19,839
Less accumulated depreciation, depletion and amortization	14,692	756	15,448
Net capitalized costs	$ 4,137	$ 254	$ 4,391
2007			
Natural gas and oil properties:			
Costs subject to amortization	$ 17,631	$ 546	$ 18,177
Costs not subject to amortization	474	265	739
	18,105	811	18,916
Less accumulated depreciation, depletion and amortization	11,847	255	12,102
Net capitalized costs	$ 6,258	$ 556	$ 6,814

(1) Capitalized costs for Egypt were $31 million and $14 million as of December 31, 2008 and 2007.

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(1)	Worldwide
2008			
Property acquisition costs			
Proved properties	$ 51	$	$ 51
Unproved properties	74	1	75
Exploration costs	438	104	542
Development costs	938	93	1,031

Costs expended	1,501	198	1,699
Asset retirement obligation costs	19		19
Total costs incurred	$ 1,520	$ 198	$ 1,718
2007			
Property acquisition costs			
Proved properties	$ 964	$	$ 964
Unproved properties	262	5	267
Exploration costs	398	199	597
Development costs	735	26	761
Costs expended	2,359	230	2,589
Asset retirement obligation costs	38	7	45
Total costs incurred	$ 2,397	$ 237	$ 2,634
Unconsolidated investment in Four Star	$ 27	$	$ 27
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

(1) Costs incurred for Egypt were $26 million, $10 million and $4 million for the years ended December 31, 2008, 2007 and 2006.

Pursuant to the full cost method of accounting, we capitalize certain general and administrative expenses directly 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 $85 million, $69 million and $50 million for the years ended December 31, 2008, 2007 and 2006. We also capitalized interest of $29 million, $35 million and $30 million for the years ended December 31, 2008, 2007 and 2006.

In our January 1, 2009 reserve report, the amounts estimated to be spent in 2009, 2010 and 2011 to develop our consolidated worldwide proved undeveloped reserves are $245 million, $207 million and $191 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 within three years.

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, 2008, pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2008	Costs Excluded for Years Ended[1] December 31 2008	2007	2006	Cumulative Balance December 31, 2005
United States					
Acquisition	$ 256	$ 72	$ 115	$ 12	$ 57
Exploration	70	55	6	8	1
Development					
Total United States	326	127	121	20	58
Brazil & Egypt[2]					
Acquisition	7		4	1	2
Exploration	180	76	81	14	9
Development					
Total Brazil & Egypt	187	76	85	15	11
Worldwide	$ 513	$ 203	$ 206	$ 35	$ 69

(1) Includes capitalized interest of $24 million, $33 million and $24 million for the years ended December 31, 2008, 2007 and 2006.

(2) Includes $31 million related to Egypt at December 31, 2008.

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, 2008 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, conducted an audit of the estimates of 80 percent of our consolidated natural gas and oil reserves as of December 31, 2008. The scope of the audit performed by Ryder Scott included the preparation of an independent estimate of proved natural gas and oil reserves estimates for fields comprising approximately 80 percent of our total worldwide present value of future cash flows (pretax). The specific fields included in Ryder Scott s audit represented the largest fields based on value. Ryder Scott also conducted an audit of the estimates of 84 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 Volumes (in Bcfe)
	United States	Brazil	Worldwide	United States	Brazil	Worldwide	United States	
Consolidated								
January 1, 2006	1,831	56	1,887	43,228	32,250	75,478	12,562	2,415
Revisions due to prices	(48)		(48)	(1,007)		(1,007)	(152)	(55)
Revisions other than price	56	(1)	55	(507)	(365)	(872)	(1,682)	40
Extensions and discoveries	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
Revisions due to prices	28		28	2,336	10	2,346	154	43
Revisions other than price	(39)	(1)	(40)	3,711	1,010	4,721	(35)	(12)
Extensions and discoveries	296		296	5,876		5,876	1,681	341
Purchases of reserves in place	339		339	3,111		3,111		357
Sales of reserves in place	(2)		(2)	(73)		(73)		(2)
Production	(238)	(4)	(242)	(5,966)	(157)	(6,123)	(1,698)	(289)
December 31, 2007	2,248	51	2,299	49,674	32,710	82,384	10,114	2,853
Revisions due to prices	(136)	(1)	(137)	(26,018)	(29,406)	(55,424)	(985)	(476)
Revisions other than price	(52)		(52)	(2,546)		(2,546)	(891)	(72)
Extensions and discoveries	475		475	16,468		16,468	456	577
Purchases of reserves in place	10		10	1,295		1,295	68	18
Sales of reserves in place	(224)		(224)	(10,440)		(10,440)	(2,754)	(303)
Production	(230)	(3)	(233)	(4,523)	(124)	(4,647)	(1,849)	(272)

December 31, 2008	2,091	47	2,138	23,910	3,180	27,090	4,159	2,325
Proved developed reserves								
December 31, 2006	1,469	23	1,492	29,616	824	30,440	8,665	1,727
December 31, 2007	1,738	19	1,757	35,070	680	35,750	8,132	2,020
December 31, 2008	1,564	12	1,576	19,799	615	20,414	3,619	1,720
Unconsolidated investment in Four Star								
December 31, 2008								
Net proved developed and undeveloped reserves	176		176	2,199		2,199	5,518	222
Proved developed reserves	149		149	2,151		2,151	4,516	189
December 31, 2007								
Net proved developed and undeveloped reserves	200		200	2,858		2,858	6,411	256
Proved developed reserves	170		170	2,804		2,804	5,345	219
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

In 2008, of the 577 Bcfe of extensions and discoveries, 201 Bcfe related to the Raton area in northern New Mexico and 132 Bcfe related to the Rockies. However, approximately 130 Bcfe of the 132 Bcfe related to the Rockies was also recorded as a pricing revision due to unfavorable commodity prices at December 31, 2008. We also had 99 Bcfe of extensions and discoveries related to the Arklatex area, 38 Bcfe related to the McCook area and 31 Bcfe related to the Zapata area, both in the south Texas area and 22 Bcfe related to High Island in the Gulf of Mexico.

In 2007, of the 341 Bcfe of extensions and discoveries, 80 Bcfe related to the Raton area in northern New Mexico, 43 Bcfe related to the McCook area in south Texas, 34 Bcfe related to the Zapata area in south Texas, 26 Bcfe related to the success in the Niobrara and Johnson counties in Wyoming, 22 Bcfe related to the Mustang Island 739/740 block in the Gulf of Mexico and 20 Bcfe related to the Victoria area in south Texas.

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In 2006, of the 299 Bcfe of extensions and discoveries, 45 Bcfe related to the coal bed methane projects in central Alabama, 37 Bcfe related to the House Creek Parkman and County Line areas in northeast Wyoming, 35 Bcfe related to the McCook area in South Texas, 27 Bcfe related to the Raton area in northern New Mexico, 18 Bcfe related to the Victoria area in south Texas, 18 Bcfe related to the Bear Creek area in northern Louisiana, and 16 Bcfe related to the Minden area in east Texas.

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. Subsequent to December 31, 2008, there have been no major discoveries or other favorable events that affect proved reserves; however, commodity prices have continued to decline and sustained lower commodity prices could result in reduced estimated proved reserves in future periods.

In December 2008, the Securities and Exchange Commission issued a final rule adopting revisions to its oil and gas reporting requirements. The revisions will impact the determination and disclosure of oil and gas reserves information. Among other things, the new rules will revise the definition of proved reserves and will require companies to use a twelve month average commodity price in determining estimated proved reserves, rather than a period end price as is currently required. These changes, along with other proposed changes, may impact our supplemental natural gas and oil operations disclosures in the future. The provisions of this final rule are effective on December 31, 2009, and cannot be applied earlier than that date.

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
2008			
Net Revenues[1]			
Sales to external customers	$ 951	$ 20	$ 971
Affiliated sales	1,421		1,421
Total	2,372	20	2,392
Cost of products and services[2]	(79)		(79)
Production costs[3]	(354)	(9)	(363)
Ceiling test charges[4]	(2,181)	(488)	(2,669)
Depreciation, depletion and amortization	(768)	(14)	(782)
	(1,010)	(491)	(1,501)
Income tax benefit[5]	364		364
Results of operations from producing activities	$ (646)	$ (491)	$ (1,137)
Equity earnings from unconsolidated investment in Four Star[6]	$ (93)	$	$ (93)
Depreciation, depletion and amortization ($/Mcfe)[7]	$ 2.87	$ 3.62	$ 2.88
2007			
Net Revenues[1]			
Sales to external customers	$ 1,085	$ 25	$ 1,110
Affiliated sales	1,149	(8)	1,141
Total	2,234	17	2,251
Cost of products and services[2]	(72)		(72)
Production costs[3]	(327)	(11)	(338)
Depreciation, depletion and amortization	(748)	(16)	(764)
	1,087	(10)	1,077
Income tax (expense) benefit	(392)	4	(388)
Results of operations from producing activities	$ 695	$ (6)	$ 689
Equity earnings from unconsolidated investment in Four Star	$ 12	$	$ 12
Depreciation, depletion and amortization ($/Mcfe)[7]	$ 2.63	$ 3.10	$ 2.64
2006			
Net Revenues[1]			

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[2]	(58)		(58)
Production costs[3]	(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	$ 10	$	$ 10
Depreciation, depletion and amortization ($/Mcfe)[7]	$ 2.37	$ 2.14	$ 2.36

(1) Excludes the effects of natural gas and oil derivative contracts.

(2) Cost of products and services consists of transportation costs.

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

(4) Includes $9 million related to Egypt.

(5) See Note 5 for a description of the deferred tax valuation allowance recorded in 2008 associated with our Brazil

net operating losses and ceiling test charge.

(6) Includes a $125 million impairment charge related to Four Star.

(7) Includes accretion expense on asset retirement obligations of $0.05/Mcfe in 2008 and $0.07/Mcfe in 2007 and 2006.

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
2008			
Future cash inflows[1]	$ 11,667	$ 242	$ 11,909
Future production costs	(3,495)	(45)	(3,540)
Future development costs	(1,406)	(65)	(1,471)
Future income tax expenses	(1,152)	(20)	(1,172)
Future net cash flows	5,614	112	5,726
10% annual discount for estimated timing of cash flows	(2,274)	(56)	(2,330)
Standardized measure of discounted future net cash flows	$ 3,340	$ 56	$ 3,396
2007			
Future cash inflows[1]	$ 19,329	$ 3,226	$ 22,555
Future production costs	(4,822)	(560)	(5,382)
Future development costs	(1,805)	(444)	(2,249)
Future income tax expenses	(3,144)	(625)	(3,769)
Future net cash flows	9,558	1,597	11,155
10% annual discount for estimated timing of cash flows	(3,704)	(617)	(4,321)
Standardized measure of discounted future net cash flows	$ 5,854	$ 980	$ 6,834
Standardized measure of discounted future net cash flows, including effects of hedging activities	$ 5,902	$ 980	$ 6,882
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
Unconsolidated Investment in Four Star			
Standardized measure of discounted future net cash flows 2008	$ 396	$	$ 396

2007	$	444	$		$	444
2006	$	323	$		$	323

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2008. United States excludes $61 million and $219 million of future net cash inflows attributable to derivatives designated as accounting hedges in years 2007 and 2006. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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 $5.71, $6.80 and $5.64 per MMBtu for natural gas and $44.60, $95.98 and $61.05 per barrel of oil at December 31, 2008, 2007 and 2006. In the United States, after adjustments for transportation and other charges, net prices were $5.12 per Mcf of gas, $35.67 per barrel of oil and $27.08 per barrel of NGL at December 31, 2008. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price and cost changes.

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]		
	2008	2007	2006
		(In millions)	
Sales and transfers of natural gas and oil produced net of production costs	$ (2,059)	$ (1,657)	$ (1,516)
Net changes in prices and production costs	(3,380)	2,723	(2,891)
Extensions, discoveries and improved recovery, less related costs	1,136	910	549
Changes in estimated future development costs	342	(4)	(55)
Previously estimated development costs incurred during the period	141	200	192
Revision of previous quantity estimates	(887)	117	(38)
Accretion of discount	622	501	827
Net change in income taxes	1,458	(1,333)	1,123
Purchases of reserves in place	36	810	4
Sales of reserves in place	(603)	(7)	(42)
Change in production rates, timing and other	(244)	95	(289)
Net change	$ (3,438)	$ 2,355	$ (2,136)

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

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SCHEDULE II
EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007 and 2006
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2008					
Allowance for doubtful accounts	$ 17	$ (2)	$	$ (6)	$ 9
Valuation allowance on deferred tax assets	137	202(1)		(2)	337
Legal reserves(2)	460	(91)	(16)	(280)(4)	73
Environmental reserves	260	(11)	(44)	(1)	204
Regulatory reserves(5)	10		(10)		
2007					
Allowance for doubtful accounts	$ 28	$ (4)	$ (5)(6)	$ (2)	$ 17
Valuation allowance on deferred tax assets	127	10			137
Legal reserves(2)	548	36	(128)(3)	4	460
Environmental reserves	314	21	(75)		260
Regulatory reserves(5)	65	61	(116)		10
2006					
Allowance for doubtful accounts	$ 65	$ (5)	$ (27)(6)	$ (5)	$ 28
Valuation allowance on deferred tax assets	107	23		(3)	127
Legal reserves(2)	574	48	(74)		548
Environmental reserves	348	30	(64)		314
Regulatory reserves(5)	1	65	(1)		65

(1) Amounts reflect valuation allowances associated with Brazil net operating losses and ceiling test charges.

(2) Amounts are net of related insurance receivables.

(3) Included is the settlement of our shareholder

litigation lawsuits.

(4) Amount reclassified as SFAS No. 106 liability (see Note 14).

(5) In 2006 and 2007, we recorded reserves for rate refunds under EPNG s rate case which was settled in 2007 and refunds paid to customers.

(6) Relates primarily to the sale of our accounts receivable under an accounts receivable sales program.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2008, 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. 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 errors 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. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO have concluded that our disclosure controls and procedures are effective at a reasonable level of assurance at December 31, 2008. See 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 during the fourth quarter of 2008 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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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 2009 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 2008, 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 2009 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 2009 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 2009 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information appearing under the caption Proposal No. 4 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 and Committees Policy for Approval of Audit and Non-Audit Fees, in our Proxy Statement for the 2009 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:

	Page
Reports of Independent Registered Public Accounting Firms	88
Consolidated Statements of Income	92
Consolidated Balance Sheets	93
Consolidated Statements of Cash Flows	95
Consolidated Statements of Stockholders Equity	96
Consolidated Statements of Comprehensive Income	97
Notes to Consolidated Financial Statements	98
2. Financial statement schedules and supplementary information required to be submitted Schedule II Valuation and Qualifying Accounts	152
3. Exhibits	157

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.

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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 2nd day of March, 2009.

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)	March 2, 2009
/s/ D. Mark Leland D. Mark Leland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2009
/s/ John R. Sult John R. Sult	Senior Vice President and Controller (Principal Accounting Officer)	March 2, 2009
/s/ Ronald L. Kuehn, Jr. Ronald L. Kuehn, Jr.	Chairman of the Board	March 2, 2009
/s/ Juan Carlos Braniff Juan Carlos Braniff	Director	March 2, 2009
/s/ James L. Dunlap James L. Dunlap	Director	March 2, 2009
/s/ Robert W. Goldman Robert W. Goldman	Director	March 2, 2009
/s/ Anthony W. Hall, Jr. Anthony W. Hall, Jr.	Director	March 2, 2009
/s/ Thomas R. Hix	Director	March 2, 2009

Thomas R. Hix		
/s/ William H. Joyce	Director	March 2, 2009
William H. Joyce		
/s/ Ferrell P. McClean	Director	March 2, 2009
Ferrell P. McClean		
/s/ Steven J. Shapiro	Director	March 2, 2009
Steven J. Shapiro		
/s/ J. Michael Talbert	Director	March 2, 2009
J. Michael Talbert		
/s/ Robert F. Vagt	Director	March 2, 2009
Robert F. Vagt		
/s/ John L. Whitmire	Director	March 2, 2009
John L. Whitmire		
/s/ Joe B. Wyatt	Director	March 2, 2009
Joe B. Wyatt		

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EL PASO CORPORATION
EXHIBIT INDEX
December 31, 2008

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by * . All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement.

Exhibit Number	Description
3.A	Second Amended and Restated Certificate of Incorporation (Exhibit 3.A to our Current Report on Form 8-K filed with the SEC on May 31, 2005).
3.B	By-laws effective as of December 6, 2007 (Exhibit 3.B to our Current Report on Form 8-K filed with the SEC on December 6, 2007).
4.A	Indenture dated as of May 10, 1999, by and between El Paso and HSBC Bank USA, National Association (as successor-in-interest to JPMorgan Chase Bank (formerly The Chase Manhattan Bank)), as Trustee (Exhibit 4.A to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005).
4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (Exhibit 3.A to our Current Report on Form 8-K filed with the SEC on May 31, 2005).
4.C	Registration Rights Agreement, dated April 15, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on April 15, 2005).
4.D	Tenth Supplemental Indenture dated as of December 28, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on January 4, 2006).
4.E	Eleventh Supplemental Indenture dated as of August 31, 2006, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
4.F	Twelfth Supplemental Indenture dated as of June 18, 2007 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Quarterly Report on Form 10-Q for the period ended June 30, 2007, filed with the SEC on August 7, 2007).
4.G	Thirteenth Supplemental Indenture dated as of May 30, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4 to our Quarterly Report on Form 10-Q for the period ended June 30, 2008, filed with the SEC on August 8, 2008).
*4.H	Fourteenth Supplemental Indenture dated as of December 12, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999.

*4.I	Fifteenth Supplemental Indenture, dated as of February 9, 2009 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999.

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Exhibit Number	Description
+10.A	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.F to our Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on September 30, 2004); Amendment No. 1 effective as of January 1, 2007 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.A.1	Amendment No. 2 effective as of January 1, 2008 to the 1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003.
+10.B	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999 (Exhibit 10.G to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.G.1 to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 2 effective as of February 7, 2001 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.B.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of October 26, 2006 to the Stock Option Plan for Non-Employee Directors (Exhibit 10.N to our Quarterly Report on Form 10-Q for the period ended on September 30, 2006, filed with the SEC on November 6, 2006).
*+10.C	2001 Stock Option Plan for Non-Employee Directors effective as of January 29, 2001.
+10.C.1	Amendment No. 1 effective as of February 7, 2001 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.C.2	Amendment No. 2 effective as of December 4, 2003 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.C.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.C.3	Amendment No. 3 effective as of October 26, 2006 to the 2001 Stock Option Plan for Non-Employee Directors (Exhibit 10.O to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.D	1995 Omnibus Compensation Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 1 effective as of December 3, 1998 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 2 effective as of January 20, 1999 to the 1995 Omnibus Compensation Plan (Exhibit 10.I.2 to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 3 effective as of October 26, 2006 to the 1995 Omnibus Compensation Plan (Exhibit 10.L to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.E	

	1999 Omnibus Incentive Compensation Plan dated January 20, 1999 (Exhibit 10.E to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.E.1	Amendment No. 1 effective as of February 7, 2001 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.E.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.E.2	Amendment No. 2 effective as of May 1, 2003 to the 1999 Omnibus Incentive Compensation Plan

Exhibit Number	Description
+10.E.3	Amendment No. 3 effective as of October 26, 2006 to the 1999 Omnibus Incentive Compensation Plan (Exhibit 10.K to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.F	2001 Omnibus Incentive Compensation Plan effective as of January 29, 2001 (Exhibit 10.F. to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.F.1	Amendment No. 1 effective as of February 7, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.F.2	Amendment No. 2 effective as of April 1, 2001 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.F.3	Amendment No. 3 effective as of July 17, 2002 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.F.4	Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan.
*+10.F.5	Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan.
+10.F.6	Amendment No. 6 effective as of October 26, 2006 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.M to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.G	Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of November 7, 2002 to the Supplemental Benefits Plan (Exhibit 10.G.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of June 1, 2004 to the Supplemental Benefits Plan (Exhibit 10.L.1 to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 3 effective December 17, 2004 to the Supplemental Benefits Plan (Exhibit 10.UU to our Quarterly Report on Form 10-Q for the period ended September 30, 2004, filed with the SEC on December 20, 2004); Amendment No. 4 to the Supplemental Benefits Plan effective as of December 31, 2004 (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on March 7, 2006); Amendment No. 5 effective as of January 1, 2007 to the Supplemental Benefits Plan Amended and Restated effective December 7, 2001 (Exhibit 10.G.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.H	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 1 effective as of February 7, 2001 to the Senior Executive

	Survivor Benefit Plan (Exhibit 10.H.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of October 1, 2002 to the Senior Executive Survivor Benefit Plan (Exhibit 10.H.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.I	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.N to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005).
+10.I.1	Amendment No. 1 effective as of February 7, 2001 to the Key Executive Severance Protection Plan (Exhibit 10.I.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).

Exhibit Number	Description
+10.I.2	Amendment No. 2 effective as of November 7, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.I.3	Amendment No. 3 effective as of December 6, 2002 to the Key Executive Severance Protection Plan (Exhibit 10.I.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.I.4	Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan.
+10.I.5	Amendment No. 5 effective as of January 1, 2007 to the Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.I.5 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.J	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.P to our Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on September 30, 2004); Amendment No. 1 effective as of January 1, 2007 to the 2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.J.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.K	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 1 effective as of February 7, 2001 to the Director Charitable Award Plan (Exhibit 10.K.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of December 4, 2003 to the Director Charitable Award Plan (Exhibit 10.Q.1 to our Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on September 30, 2004).
+10.L	Strategic Stock Plan Amended and Restated effective as of December 3, 1999 (Exhibit 10.L to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of February 7, 2001 to the Strategic Stock Plan (Exhibit 10.L.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of November 7, 2002 to the Strategic Stock Plan (Exhibit 10.L.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 6, 2002 to the Strategic Stock Plan (Exhibit 10.L.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of January 29, 2003 to the Strategic Stock Plan (Exibit 10.L.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 5 effective as of October 26, 2006 to the Strategic Stock Plan (Exhibit 10.J to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.M	Domestic Relocation Policy effective November 1, 1996 (Exhibit 10.R to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005).
+10.N	

Executive Award Plan of Sonat Inc. Amended and Restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.S to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.N.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment to the Executive Award Plan of Sonat Inc. effective as of October 26, 2006 (Exhibit 10.H to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).

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Exhibit Number	Description
+10.O	Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.O to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 1 effective as of December 1, 2000 to the Omnibus Plan for Management Employees (Exhibit 10.O.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 2 effective as of February 7, 2001 to the Omnibus Plan for Management Employees (Exhibit 10.O.2 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 3 effective as of December 7, 2001 to the Omnibus Plan for Management (Exhibit 10.O.3 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 4 effective as of December 6, 2002 to the Omnibus Plan for Management Employees (Exhibit 10.O.4 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008); Amendment No. 5 effective as of October 26, 2006 to the Corporation Omnibus Plan for Management Employees (Exhibit 10.I to our Quarterly Report on Form-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
*+10.P	Severance Pay Plan Amended and Restated effective as of October 1, 2002.
+10.P.1	Amendment No. 1 effective January 1, 2007 to the Severance Pay Plan Amended and Restated effective as of October 1, 2002 (Exhibit 10.P.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.P.2	Amendment No. 2 effective January 1, 2008 to the Severance Pay Plan Amended and Restated effective as of October 1, 2002.
+10.Q	Letter Agreement dated September 20, 2006 between El Paso Corporation and Brent J. Smolik (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC October 16, 2006).
*+10.R	Letter Agreement dated July 15, 2003 between El Paso and Douglas L. Foshee.
*+10.S	Letter Agreement dated December 18, 2003 between El Paso and Douglas L. Foshee.
*+10.T	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later.
+10.U	Form of Indemnification Agreement executed by El Paso for the benefit of each officer and effective the date listed in Schedule A thereto (Exhibit 10.F to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.V	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 17, 2004 (Exhibit 10.XX to our Quarterly Report on Form 10-Q for the period ended September 30, 2004, filed with the SEC on December 20, 2004).
10.W	Agreement With Respect to Collateral dated as of June 11, 2004, by and among El Paso Production Oil & Gas USA, L.P., a Delaware limited partnership, Bank of America, N.A., acting solely in its capacity as Collateral Agent under the Collateral Agency Agreement, and The Office of the Attorney General of the

	State of California, acting solely in its capacity as the Designated Representative under the Designated Representative Agreement (Exhibit 10.HH to our Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on September 30, 2004).
10.X	Purchase Agreement dated April 11, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on April 15, 2005).

Exhibit Number	Description
+10.Y	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC May 31, 2005); Amendment No. 1 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of October 26, 2006 (Exhibit 10.P to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006); Amendment No. 2 effective as of January 1, 2007 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.Y.1	Amendment No. 3 effective as of January 1, 2008 to the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005.
+10.Z	El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of May 26, 2005 (Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on May 31, 2005); Amendment No. 1 to the 2005 Omnibus Incentive Compensation Plan effective as of December 2, 2005 (Exhibit 10.HH.1 to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 2 to the El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of October 26, 2006 (Exhibit 10.Q to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006); Amendment No. 3 to the El Paso Corporation 2005 Omnibus Incentive Compensation Plan effective as of May 26, 2005 (Exhibit 10.Z.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
+10.AA	El Paso Corporation Employee Stock Purchase Plan, Amended and Restated Effective as of July 1, 2005 (Exhibit 10.E to our Quarterly Report on Form 10-Q for the period ended June 30, 2005, filed with the SEC on August 5, 2005); Amendment No. 1 to the El Paso Corporation Employee Stock Purchase Plan effective as of October 26, 2006 (Exhibit 10.G to our Quarterly Report on Form 10-Q for the period ended September 30, 2006, filed with the SEC on November 6, 2006).
+10.BB	2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.KK to our Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 28, 2005); Amendment No. 1 effective as of January 1, 2007 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005 (Exhibit 10.BB.1 to our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 28, 2008).
*+10.BB.1	Amendment No. 2 effective as of January 1, 2008 to the 2005 Supplemental Benefits Plan effective as of January 1, 2005.
10.CC	Credit Agreement dated as of July 19, 2006 among El Paso Corporation, as Borrower, Deutsche Bank AG New York Branch, as Initial Lender, Issuing Bank, Administrative Agent and Collateral Agent (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on July 20, 2006).
10.DD	Third Amended and Restated Credit Agreement dated as of November 16, 2007, among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Current Report on Form 8-K filed with

the SEC on November 21, 2007).

10.EE	Third Amended and Restated Security Agreement dated as of November 16, 2007, made by among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on November 21, 2007).

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Exhibit Number	Description
10.FF	Third Amended and Restated Subsidiary Guarantee Agreement dated as of November 16, 2007, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.C to our Current Report on Form 8-K filed with the SEC on November 21, 2007).
10.GG	Purchase and Sale Agreement dated December 22, 2006, among El Paso Corporation, El Paso CNG Company, L.L.C., and TransCanada American Investments Ltd. (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on December 29, 2006).
10.HH	Purchase and Sale Agreement dated December 22, 2006, among El Paso Great Lakes Company, L.L.C., TC GL Intermediate Limited Partnership and TransCanada PipeLine USA Ltd. (Exhibit 10. B to our Current Report on Form 8-K filed with the SEC on December 29, 2006).
*12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
*21	Subsidiaries of El Paso Corporation.
*23.A	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
*23.B	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers, LLP (Four Star)
*23.D	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers (Citrus)
*31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.A	Ryder Scott reserve report for El Paso Exploration & Production Company as of December 31, 2008.
*99.B	Ryder Scott reserve report for Four Star Oil & Gas Company as of December 31, 2008.