EL PASO CORP/DE
Form 10-K
March 01, 2011

Table of Contents

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, 2010

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o.

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (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 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, 2010, 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: $7,821,067,148.

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

Common Stock, par value $3 per share. Shares outstanding on February 22, 2011: 704,754,155

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 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this report. These will be filed no later than April 30, 2011.

EL PASO CORPORATION
TABLE OF CONTENTS

Table of Contents

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

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

Table of Contents

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.

Our operations are conducted through two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our Corporate and other activities include our general and administrative functions, and other miscellaneous businesses, including our newly formed midstream business. For a further discussion of our business segments, see below and in Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Pipelines Segment

Our Pipelines segment includes our interstate natural gas transmission systems and related operations conducted through eight wholly or majority owned pipeline systems and two partially owned systems. These systems consist of approximately 43,100 miles of pipe that connect the nation s principal natural gas supply regions to five major 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. Our Pipelines segment also includes storage and LNG terminalling related facilities including our ownership of storage capacity through our transmission systems, three underground natural gas storage facilities, and two LNG terminalling facilities, one of which is under construction and the other which is located in Elba Island, Georgia. We provide approximately 240 Bcf of storage capacity and our LNG receiving terminal has a peak sendout capacity of 1.8 Bcf/d. The size, connectivity and diversity of our U.S. pipeline systems provide growth opportunities through infrastructure development or large scale expansion projects and gives us the ability to adapt to 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 developing growth projects in our market and supply areas.

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

- providing outstanding customer service;
- executing successfully on time and on budget 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.

Table of Contents

Natural Gas Pipeline Systems. The tables below provide more information on our pipeline systems:

		As of December 31, 2010						
Transmission System	**Supply and Market Region**	**Ownership Percentage (Percent)**	**Miles of Pipeline**	**Design Capacity (MMcf/d)**	**Storage Capacity (Bcf)**	**Average Throughput[1] 2010**	**2009 (BBtu/d)**	**2008**
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	14,100	7,208	93[2]	5,081	4,614	4,864
El Paso Natural Gas (EPNG)	Extends from the San Juan, Permian and Anadarko basins to California, its single largest market, as well as markets in Arizona, Nevada, New Mexico, Oklahoma, Texas and northern Mexico.	100	10,200	5,650[3]	44	3,356	3,937	4,379
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	500	400[4]		421	379	349
Cheyenne Plains Gas Pipeline (CPG) [5]	Extends from Cheyenne hub and Yuma County in Colorado to various pipeline interconnections near Greensburg, Kansas.	100	400	934		751	841	898

(1) Includes throughput transported on behalf of affiliates.

(2) Includes 29 Bcf of storage capacity from Bear Creek Storage Company, L.L.C (Bear Creek) which is owned equally by TGP and Southern Natural Gas (SNG).

(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.

(5) We own 100 percent of the common shares. See Part II, Item 8, Financial Statements and Supplementary Data, Note 17.

Table of Contents

		As of December 31, 2010						
Transmission System	Supply and Market Region	Ownership Percentage (Percent)	Miles of Pipeline	Design Capacity (MMcf/d)	Storage Capacity (Bcf)	Average Throughput[1] 2010	2009 (BBtu/d)	2008
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.	72[5]	4,300	4,592	37[3]	2,131	2,299	2,225
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.	71[5]	7,600	3,700	60[2]	2,505	2,322	2,339
Wyoming Interstate (WIC)	Extends from western Wyoming, eastern Utah, western Colorado and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	51[5]	800	3,538		2,472	2,652	2,543
Elba Express	Extends from the Elba Island LNG terminal near Savannah to Hart County, Georgia and Anderson County, South Carolina. Also connects with SNG and various power plants in Georgia.	51[5]	200	945		[4]		
		50	5,000	2,254		2,288	2,250	2,147

Florida Gas Transmission (FGT)[6]	Extends from south Texas to South Florida.

[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] Includes 6 Bcf of storage capacity from Totem Gas Storage which is owned by WYCO Development L.L.C. (WYCO), our 50 percent equity investee.

[4] This system was placed in service in March 2010 and although capacity is under contract, the average volumes transported during the year ended December 31, 2010 were not material.

[5] Includes direct ownership of these systems and indirect ownership though our limited and general partner interest in our master limited partnership, El Paso Pipeline Partners, L.P. (EPB). As the general partner, we also hold incentive distribution rights which pay an increasing percentage interest in quarterly distributions as further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 14.

[6] This system is operated by Southern Union Company and we have a 50 percent equity interest in Citrus Corp. (Citrus), which owns this system.

Table of Contents

WYCO Joint Venture. We own a 50 percent interest in WYCO, a joint venture with an affiliate of Public Service Company of Colorado (PSCo). WYCO owns the 164 mile High Plains pipeline and Totem Gas Storage facilities located in Northeast Colorado which are operated by us. The Totem Gas Storage facility consists of a 6 Bcf natural gas storage field that services and interconnects with the High Plains pipeline. WYCO also owns a state regulated intrastate 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, and a compressor station in Wyoming leased by us.

Federal Energy Regulatory Commission (FERC) Approved Pipeline Projects. As of December 31, 2010, we had the following significant FERC approved pipeline expansion projects on our systems. For a further discussion of other expansion projects, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Project	Existing System	Capacity (MMcf/d)	Description	Anticipated Completion or In-Service Date
FGT Phase VIII	FGT	800	To add more than 483 miles of pipeline loops, laterals, and mainline and 213,600 of horsepower compression	April 2011
Ruby Pipeline		1,490	To add approximately 680 miles of pipeline and 157,000 of horsepower compression	July 2011
South System III (Phases I-III)	SNG	370	To add 81 miles of pipeline and 17,310 of horsepower compression; each phase will add an additional 122 MMcf/d of capacity	2011-2012[1]
Southeast Supply Header Phase II[2]	SNG	350	To add approximately 26,000 of horsepower compression to the jointly owned pipeline facilities	June 2011
300 Line Project	TGP	350	To add 128 miles of pipeline and approximately 55,000 horsepower of compression at two new compressor stations and at certain existing compressor stations	November 2011

(1) The South System III expansion project consists of three phases. In January 2011, Phase I of the project was placed in service. Phases II and III are expected to be placed in service in June 2011 and June 2012, respectively.

(2) This project is operated by Spectra Energy Corp.

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 underground natural gas storage facilities:

	As of December 31, 2010		
Storage Facility	**Ownership Interest (Percent)**	**Storage Capacity (Bcf)**	**Location**
Bear Creek	85(1)	58(2)	Louisiana
Totem Gas Storage	36(1)	6(3)	Colorado
Young Gas Storage	48	6(4)	Colorado

(1) Includes direct ownership and indirect ownership through our proportionate interest in our master limited partnership, EPB.

(2) Approximately 29 Bcf is contracted to each SNG and TGP.

(3) Maximum withdrawal rate of 200 MMcf/d and a maximum injection rate of 100 MMcf/d.

(4) Amount is not adjusted for our ownership interest in these facilities.

LNG Facilities

Southern LNG Company, L.L.C. (SLNG). We own a 51 percent interest in SLNG which owns a LNG receiving terminal located on Elba Island, near Savannah, Georgia, with a peak sendout capacity of 1.8 Bcf/d and a storage capacity of 11.5 Bcfe. The capacity at the terminal is contracted with subsidiaries of BG LNG Services, LLC and Shell NA LNG LLC. The Elba Island LNG terminal is directly connected to three interstate pipelines and indirectly connected to two others, and thus is readily accessible to the southeast and mid-Atlantic markets. SNG operates the Elba Island LNG terminal. The firm SLNG service agreements are supported by parent guarantees from BG and Shell that secure the timely performance of the obligations of those agreements.

Southern Gulf LNG Company, L.L.C. We also have a 50 percent interest in the Gulf LNG Clean Energy Project (GLNG), which is constructing an LNG terminal in Pascagoula, Mississippi with a peak sendout capacity of 1.5 Bcf/d that is expected to be placed in service in October 2011.

Master Limited Partnership. At December 31, 2010, our master limited partnership, EPB, owns (i) 100 percent of WIC, Elba Express, and SLNG, (ii) a 60 percent general partner interest in SNG and (iii) a 58 percent general partner interest in CIG. As of December 31, 2010, our ownership interest in EPB is 51 percent, including our 2 percent general partner interest.

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.

The natural gas industry is undergoing a major shift in supply sources. Production from conventional sources is declining while production from unconventional sources, such as shales, is rapidly increasing. This shift will affect the supply patterns, the flows and rates that can be charged on pipeline systems. The impact will vary among pipelines according to the location and the number of competitors attached to these new supply sources. One of our pipelines is connected to two major shale formations: the Haynesville shale in northern Louisiana and Texas and the Marcellus shale in Pennsylvania. It is possible that gas from these sources will increasingly displace receipts over time from traditional sources in south Texas and the Gulf of Mexico on our system. In addition, one of our systems is near the Eagle Ford Shale formation in south Texas, which could be a major source of supply into the system in the future and could impact the flows on the system and the array of shipper contracts.

Another change in the supply patterns is the reduction in imports from Canada. This decrease has been the result of declining production and increasing demand in Canada. This reduction has led to increased demand for domestic supplies and related transportation services over the last several years, a trend which may continue in the future. On the other border, exports to Mexico are increasing and may increase further over time as demand growth exceeds production growth in that country. The increase in demand for gas and transportation caused by these trends in Canada and Mexico could be partially offset by imports of LNG. Imports of LNG have fluctuated in the past in response to changing gas prices within North America, Europe and Asia. 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.

Table of Contents

However, these LNG delivery systems may also compete with our pipelines for transportation of gas into the market areas we serve.

Electric power generation has been the source of most of the growth in demand for natural gas over the last 10 years, and this trend is expected to continue in the future. The growth of natural gas in this sector is influenced by competition with coal and increased consumption of electricity as a result of recent economic growth. Short-term market shifts have been driven by relative costs of coal-fired generation versus gas-fired generation. A long-term market shift in the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources.

For a further discussion of factors impacting our markets and competition, See Item 1A, Risk Factors.

Our existing transportation and storage contracts expire 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. Although we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariffs, we frequently 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 firm contracts is approximately six years. The table below shows the years of expiration of our firm transportation contracts as of December 31, 2010 for our wholly and majority owned systems. For additional information on our pipeline firm transportation contracts, see Part II, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Table of Contents

The following table details information related to our pipeline systems and certain other facilities, including the customers, contracts, markets served and the competition faced by each as of December 31, 2010. 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 transport, store, inject or withdraw.

Customer Information	Contract Information	Competition
TGP		
Approximately 410 firm and interruptible customers.	Approximately 470 firm transportation contracts. Weighted average remaining contract term of approximately four years.	TGP faces competition in all of its 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, the Marcellus shale and from the Canadian border.
Major Customer: National Grid USA and subsidiaries		
(495 BBtu/d)	Expire in 2012-2013.	
(332 BBtu/d)	Expire in 2014-2029.	
EPNG		
Approximately 150 firm and interruptible customers.	Approximately 200 firm transportation contracts. Weighted average remaining contract term of approximately three years.	EPNG faces competition in the west and southwest from other existing 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, EPNG faces competition from gas imported into California from Canada and from an LNG facility located in northern Mexico.
Major Customers: Southern California Gas Company (SoCal)		
(782 BBtu/d)	Expire in 2011-2014.	
ConocoPhillips Company		
(527 BBtu/d)	Expire in 2011-2012.	
Southwest Gas Corporation		

(485 BBtu/d)	Expire in 2011-2018.

Table of Contents

Customer Information	Contract Information	Competition
MPC		
Approximately 10 firm and interruptible customers.	Approximately two firm transportation contracts. Weighted average remaining contract term of approximately five years.	MPC faces competition from other existing 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, Mojave faces competition from an LNG facility located in northern Mexico.
Major Customer:		
EPNG		
(510 BBtu/d)	Expires in 2015.	
CPG		
Approximately 50 firm and interruptible customers.	Approximately 30 firm transportation contracts. Weighted average remaining contract term of approximately six 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.		
(125 BBtu/d)	Expires in 2019.	

Customer Information	Contract Information	Competition
SNG		
Approximately 260 firm and interruptible customers.	Approximately 190 firm transportation contracts. Weighted average remaining contract term of approximately seven 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)]		
(979 BBtu/d)	Expire in 2013-2015.	
(84 BBtu/d)	Expires in 2024.	
Southern Company Services		
(43 BBtu/d)	Expire in 2011-2013.	
(390 BBtu/d)	Expire in 2017-2018.	
(375 BBtu/d)	Expires in 2032.	
Alabama Gas Corporation		
(352 BBtu/d)	Expires in 2013.	
SCANA Corporation		
(315 BBtu/d)	Expire in 2013-2019.	

(1) Atlanta Gas Light Company releases on a monthly basis a significant portion of its firm capacity to a subsidiary of SCANA Corporation.

Customer Information	Contract Information	Competition
CIG		
Approximately 110 firm and interruptible customers.	Approximately 160 firm transportation contracts. Weighted average remaining contract term of approximately seven 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 in 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		
(905 BBtu/d)	Expire in 2012-2019.	
(874 BBtu/d)	Expire in 2025-2029.	
Williams Gas Marketing, Inc.		
(395 BBtu/d)	Expire in 2011-2014.	
Pioneer Natural Resources USA, Inc.		
(109 BBtu/d)	Expire in 2014-2015.	
(202 BBtu/d)	Expire in 2020-2022.	

Table of Contents

Customer Information	Contract Information	Competition
WIC		
Approximately 50 firm and interruptible customers	Approximately 60 firm transportation contracts. Weighted average remaining contract term of approximately seven 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.		
(353 BBtu/d)	Expire in 2013-2015.	
(414 BBtu/d)	Expire in 2017-2018.	
(610 BBtu/d)	Expire in 2019-2021.	
Anadarko Petroleum Corporation		
(323 BBtu/d)	Expire in 2011-2015.	
(406 BBtu/d)	Expire in 2016-2018.	
(665 BBtu/d)	Expire in 2020-2023.	
Elba Express		
Four firm and interruptible customers	One firm transportation contract. Remaining contract term of approximately 29 years.	Elba Express competes for receipts into its system within the worldwide LNG market given its existing configuration to provide south to north takeaway capacity from the Elba LNG terminal to downstream markets in the mid-Atlantic and northeast.
Major Customer:		
Shell NA LNG LLC		
(965 BBtu/d)	Expires in 2040.	
SLNG		
Two firm customers	Two firm storage contracts. Weighted average remaining contract term of approximately 21 years.	SLNG competes with other U.S. LNG terminal facilities for global LNG supplies.
Major Customers:		
BG LNG Services, LLC	Expires in 2027.	
Shell NA LNG LLC	Expire in 2035 - 2036.	

Table of Contents

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. 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.

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

Table of Contents

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 U.S., Brazil and Egypt. We currently operate through three divisions in the U.S.: Central, Western and Gulf Coast. During 2010, in the U.S., we focused on several core programs: the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont fractured tight sands in Utah. We also established a new core oil program in the Wolfcamp Shale, which is located in the Permian Basin of West Texas. Over the past few years, we have high-graded our inventory of future drilling opportunities through producing property acquisitions, acreage acquisitions and the sale of producing properties that tended to be late in life and without meaningful future drilling opportunities. As a result, our drilling inventory has became more domestic, lower-risk and with an increased weighting toward oil-focused opportunities. As of December 31, 2010, we controlled approximately 3.7 million net leasehold acres and had proved natural gas and oil reserves of approximately 3.4 Tcfe, including 0.2 Tcfe of proved natural gas and oil reserves related to Four Star, our unconsolidated affiliate. During 2010, daily equivalent natural gas production averaged approximately 782 MMcfe/d, including 62 MMcfe/d from our equity interest in Four Star.

Table of Contents

U.S.

Central. The Central division includes operations that are primarily focused on shale gas, tight gas sands, coal bed methane and lower risk conventional producing areas, which are generally characterized by lower development costs, higher drilling success rates and longer reserve lives. We have a large inventory of drilling prospects in this division. During 2010, we invested $475 million on capital projects and production averaged 328 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2010 Capital Investment (In millions)	Average Production (MMcfe/d)
Haynesville	The Haynesville Shale is one or our core programs with shale gas production primarily from the Haynesville but also the Bossier Shale. Production continues to increase as a result of our drilling and completion program. Our operations are primarily in the Holly, Bethany Longstreet and Logansport fields.	46,000	$ 382	143
East Texas/ North Louisiana (Arklatex)	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, Bethany Longstreet and Logansport, Minden and Bald Prairie fields. In December 2010, we sold our natural gas producing properties in Mississippi and retained a land position.	165,000	$ 59	104
Shallow/ Unconventional	Established shallow coal bed methane producing areas in the Black Warrior Basin in Alabama and the Arkoma Basin in Oklahoma. Production is from vertical wells in Alabama and horizontal wells in the Hartshorne Coals in Oklahoma. We have high average working interests and have been developing our operated Shallow Unconventional properties. In addition, we have a 50 percent average working interest covering approximately 46,000 net acres operated by Black Warrior Methane Corporation which produces from the Brookwood Field. We also have approximately 207,000 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.	432,000	$ 34	81

Table of Contents

Western. The Western division includes operations that are primarily focused on natural gas and oil production from coal bed methane, shale gas and lower risk conventional producing areas. We have a large inventory of drilling prospects in this division. Our core program is the Altamont-Bluebell-Cedar Rim Field, referred to as Altamont. During 2010, we invested $181 million on capital projects and production averaged 160 MMcfe/d. The principal operating areas are listed below:

Area	Description	Net Acres	2010 Capital Investment (In millions)	Average Production (MMcfe/d)
Uintah Basin	Primarily focused on vertical fractured oil production in Altamont in Utah.	190,000	$ 149	51
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.	605,000	$ 16	76
Rocky Mountains (Rockies)	Primarily in Wyoming with a focus in the Powder River basin, consisting predominantly of operated oil fields utilizing both primary and secondary recovery methods combined with a non-operated working interest in the County Line coal bed methane unit.	242,000	$ 16	33

Gulf Coast. We focus primarily on developing and exploring for natural gas and oil in unconventional shales and tight gas sands in south Texas and the upper Gulf Coast that are characterized by lower risk, longer life production profiles. We also have operations in Gulf of Mexico and south Louisiana focused on deeper conventional reservoirs characterized by relatively high initial production rates, resulting in higher near-term cash flows and high decline rates. Our core programs are the Eagle Ford Shale and the emerging Wolfcamp Shale. The Eagle Ford oil program is the most economic of our portfolio with approximately 60 percent of total net acres located in the liquids rich area. We grew our Wolfcamp Shale position in the Permian Basin to approximately 138,000 acres. During 2010, we invested $540 million on capital projects, including approximately $265 million for the acquisition of leases in the Eagle Ford and Wolfcamp oil shale programs, and production averaged 199 MMcfe/d in the Gulf Coast division. The principal operating areas are listed below:

Area	Description	Net Acres	2010 Capital Investment (In millions)	Average Production (MMcfe/d)
Upper Texas Gulf Coast	Includes our position in the Eagle Ford Shale, located in Webb, LaSalle, Frio and Atascosa counties, where we have approximately 170,000 net acres as of December 31, 2010. The Wilcox assets include the Renger, Dry Hollow, Brushy Creek and Speaks fields located in Lavaca county, and the Graceland Field located in Colorado county.	287,000	$ 239	24
South Texas	Includes the Wolfcamp Shale in the Permian Basin in Reagan, Crockett, Upton and Irion counties in Texas, and the Vicksburg/Frio area with concentrated and contiguous assets in the Jeffress and Monte Christo fields primarily in Hidalgo county. This area also includes assets in the Alvarado and Kelsey fields in Starr and Brooks counties. The Wilcox area includes working interests in Bob West, Jennings Ranch and Roleta fields in Zapata County. Other interests in Zapata County include the Bustamante and Las Comitas fields.	213,000	$ 232	97
Gulf of Mexico/ South Louisiana	Gulf of Mexico area includes interests in 69 Blocks south of the Louisiana, Texas and Alabama shoreline focused on deep (greater than 12,000 feet) natural gas and oil reserves in relatively shallow water depths (less than 400 feet). In these areas, we have licensed over 13,500 square miles of three dimensional (3D) seismic data onshore and over 62,000 square miles of 3D seismic data offshore. South Louisiana area also includes interests in Beauregard and Vermilion Parishes.	261,000	$ 69	78

Unconsolidated Affiliate Four Star. We have an approximate 49 percent equity 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 2010, our equity interest in Four Star s daily equivalent natural gas production averaged approximately 62 MMcfe/d.

Table of Contents

International

Brazil. Our Brazilian operations cover approximately 137,000 net acres in Camamu, Espirito Santo and Potiguar basins located offshore Brazil. During 2010, we invested $66 million on capital projects in Brazil and production averaged 33 MMcfe/d. As of December 31, 2010 we have total capitalized costs of approximately $371 million, of which $182 million are unevaluated capitalized costs. Our operations in each basin are described below:

Camamu Basin. We own a 100 percent working interest in two development areas, the Camarao and Pinauna Fields. In Pinauna, we are continuing the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development. We have experienced delays in this process during both 2009 and 2010 for a number of reasons, including the Gulf of Mexico oil spill and Brazilian elections. Our ability to develop this area is dependent on the receipt of all required regulatory approvals. We have filed the required environmental reports with the Brazilian environmental agency, continue to address the agency s technical questions and expect to receive a decision on our preliminary license request during late 2011. As of December 31, 2010 we have $94 million of unevaluated capitalized costs related to the Pinauna development.

We own an 18 percent working interest in a development area, formerly part of the BM-CAL-5 block, operated by Petrobras, Brazil s state-owned energy company. In 2008, we drilled an exploratory well, and continue to search for viable commercial options to develop the resources found. In addition, we continue to own a 20 percent interest in two additional blocks in the Camamu Basin, CAL-M-312 and CAL-M-372, which are located east of and contiguous to the BM-CAL-5 block.

Espirito Santo Basin. We own an approximate 24 percent working interest in the Camarupim Field. During 2010 we began production from the second and third wells of a four well development program. Our production from these wells averaged approximately 25 MMcfe/d in 2010. We continue to work with Petrobras to connect the fourth well and anticipate bringing the well on production during 2011.

In 2010, we participated with Petrobras in drilling a second exploratory well in the ES-5 block in the Espirito Santo Basin 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 adjacent to the Camarupim Field and we anticipate testing the well in 2011. We also continue to evaluate the results of another exploratory well located to the north of Camarupim Field where drilling was completed in 2009 and hydrocarbons were found. As of December 31, 2010 we have $81 million of unevaluated capitalized costs related to our ES-5 block.

Potiguar Basin. We own a 35 percent working interest in the Pescada-Arabaiana Fields. Our production from these fields averaged approximately 8 MMcfe/d in 2010.

Egypt. As of December 31, 2010, our Egyptian operations cover approximately 1.1 million net acres in three blocks located onshore in Egypt s Western Desert. During 2010, we invested $20 million on capital projects in Egypt. We own a 60 percent working interest in the South Mariut block, which contains approximately 500,000 net acres. There was no drilling activity on this block in 2010, however we shot 3-D seismic and anticipate drilling an exploratory well in 2011. We also own a 50 percent working interest in the South Alamein block, which contains approximately 300,000 net acres, on which we drilled two wells in 2010. The wells encountered oil shows but were temporarily plugged as we continue to evaluate the results. Finally, we own a 40 percent working interest in the Tanta block, which contains approximately 300,000 net acres. During 2010, we drilled one unsuccessful well on this block. In 2011, we relinquished the block. As of December 31, 2010 we have total capitalized costs in Egypt of approximately $66 million, all of which are unevaluated.

Table of Contents

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, 2010. These reserves are based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of natural gas and oil that are ultimately recovered. The risks and uncertainties associated with estimating proved natural gas and oil reserves are discussed further in Item 1A, Risk Factors. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2010.

	Net Proved Reserves					2010
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe)	(Percent)	Production (MMcfe)
Reserves and Production by Division						
Consolidated:						
Proved						
U.S.						
Central	1,328,636	908		1,334,084	40%	119,846
Western	702,472	68,702	1	1,114,690	33%	58,307
Gulf Coast	364,285	33,630	9,050	620,365	18%	72,468
Total	2,395,393	103,240	9,051	3,069,139	91%	250,621
Brazil	85,219	2,654		101,143	3%	12,010
Total Consolidated	2,480,612	105,894	9,051	3,170,282	94%	262,631
Unconsolidated Affiliate(1)	155,031	1,623	4,458	191,518	6%	22,787
Total Combined	2,635,643	107,517	13,509	3,361,800	100%	285,418
Reserves by Classification						
Consolidated:						
Proved Developed						
U.S.	1,558,892	38,278	6,096	1,825,136	57%	
Brazil	75,171	2,403		89,589	3%	
Total	1,634,063	40,681	6,096	1,914,725(2)	60%	
Proved Undeveloped						
U.S.	836,501	64,962	2,955	1,244,003	40%	
Brazil	10,048	251		11,554	%	
Total	846,549	65,213	2,955	1,255,557	40%	
Total Consolidated	2,480,612	105,894	9,051	3,170,282(2)	100%	

Unconsolidated Affiliate[1]:					
Proved Developed	128,862	1,574	3,483	159,204	83%
Proved Undeveloped	26,169	49	975	32,314	17%
Unconsolidated Affiliate[1]	155,031	1,623	4,458	191,518	100%
Total Combined	2,635,643	107,517	13,509	3,361,800	100%

(1) Amounts represent our approximate 49 percent equity interest in Four Star.

(2) Includes 1,518 Bcfe of proved developed producing reserves representing 48 percent of consolidated proved reserves and 397 Bcfe of proved developed non-producing reserves representing 12 percent of consolidated proved reserves at December 31, 2010.

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.

Table of Contents

The table below presents proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2010.

	Net Proved Reserves (MMcfe)
As Reported	
Consolidated	3,170,282
Unconsolidated Affiliate	191,518
Total Combined	3,361,800
10 percent increase in prices[1]	
Consolidated	3,212,329
Unconsolidated Affiliate	195,125
Total Combined	3,407,454
10 percent decrease in prices[1]	
Consolidated	3,114,897
Unconsolidated Affiliate	186,260
Total Combined	3,301,157

(1) Based on the first day 12-month average U.S natural gas and oil prices we used to determine proved reserves at December 31, 2010.

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare for Four Star, our unconsolidated affiliate, has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is currently responsible for reserve reporting, strategy development, technical excellence and land administration. He has over 23 years of industry experience in various domestic and international engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates.

Table of Contents

Ryder Scott Company, L.P. (Ryder Scott) conducted an audit of the estimates of proved reserves prepared by us as of December 31, 2010. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our total proved reserves on a natural gas equivalent basis, representing 88 percent of the total discounted future net cash flows of these proved reserves. Ryder Scott also conducted an audit of the estimates we prepared of the proved reserves of Four Star as of December 31, 2010. In connection with the audit of these proved reserves, Ryder Scott reviewed 86 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 86 percent of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10 percent of Ryder Scott s estimates. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the reserves audit by Ryder Scott has a B.S. degree in mechanical engineering. He is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has over 19 years of reservoir engineering experience. His technical expertise is in the area of economic evaluations, reserves management systems, probabilistic modeling, pressure transient analysis, reservoir surveillance, production optimization, field operations, Enhanced Oil Recovery certification, computer application development and database management.

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 they are produced. Recovery of proved undeveloped (PUD) 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 PUD reserves and proved non-producing reserves are inherently 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.

We assess our PUD reserves on a quarterly basis. At December 31, 2010, we had 1,256 Bcfe of consolidated PUD reserves representing an increase of 420 Bcfe of PUD reserves compared to December 31, 2009. During 2010, we added 488 Bcfe of PUD reserves primarily due to our drilling activities in the Haynesville Shale in our Central division and the Eagle Ford Shale in our Gulf Coast division. In addition, we acquired 37 Bcfe of PUD reserves, of which 12 Bcfe occurred from the acquisition of oil properties in the Wolfcamp Shale in west Texas, in our Gulf Coast division. We had negative revisions of 3 Bcfe of PUD reserves, consisting of a negative revision of 33 Bcfe related to reserves older than five years, offset by a positive revision of 30 Bcfe related to prices and performance.

We spent approximately $199 million, $186 million and $141 million, during 2010, 2009 and 2008, respectively, to convert approximately 11 percent or 94 Bcfe, 11 percent or 69 Bcfe and 16 percent or 95 Bcfe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2010 reserve report, the amounts estimated to be spent in 2011, 2012 and 2013 to develop our consolidated worldwide PUD reserves are $597 million, $616 million and $512 million, respectively. The upward trend in the amounts estimated to be spent to develop our PUD reserves is a result of our shift in capital focus to develop our core programs. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and product prices.

Of the 1,256 Bcfe of PUD reserves at December 31, 2010, we have 62 Bcfe of undeveloped reserves that are outside of our current five-year development plan in the Raton Basin located in northern New Mexico and southern Colorado. These reserves extend beyond the five-year development plan due to pace restrictions established by the surface owner which limits the number of wells drilled annually to a level significantly below the historical levels of wells drilled per year. We have exclusive development rights in the Raton Basin with long term leases which enables us to develop beyond the five-year window. We have historical and ongoing drilling and development activities in this area, including a 25 to 30 well development program in 2011. There were no new PUD reserves booked to the Raton Basin in 2010, and the undeveloped reserves outside of our current five-year development plan represent less than five percent of the consolidated PUD reserves.

Table of Contents

Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2010, (ii) our interest in natural gas and oil wells at December 31, 2010 and (iii) our exploratory and development wells drilled during the years 2008 through 2010. 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	373,150	260,354	502,334	382,585	875,484	642,939
Western	395,281	314,094	936,076	723,185	1,331,357	1,037,279
Gulf Coast	316,468	180,340	666,273	581,182	982,741	761,522
Total United States	1,084,899	754,788	2,104,683	1,686,952	3,189,582	2,441,740
Brazil	47,377	14,492	487,022	122,182	534,399	136,674
Egypt			2,201,004	1,101,454	2,201,004	1,101,454
Worldwide Total	1,132,276	769,280	4,792,709	2,910,588	5,924,985	3,679,868

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

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

In the United States, our net developed acreage is concentrated primarily in Utah (18 percent), New Mexico (17 percent), Texas (14 percent), Louisiana (10 percent), Oklahoma (9 percent) and Alabama (9 percent). Our net undeveloped acreage is concentrated primarily in New Mexico (26 percent), Texas (21 percent), Indiana (11 percent), the Gulf of Mexico (10 percent), Colorado (7 percent) and Wyoming (6 percent). Approximately 10 percent, 6 percent and 21 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2011, 2012 and 2013, respectively. Approximately 10 percent of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012. Approximately 11 percent and 19 percent of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012 and 2013, respectively. We employ various techniques to manage the expiration of leases, including extending lease terms, drilling the acreage ourselves, or by entering into farm-out agreements with other operators.

	Natural Gas		Oil		Total		Wells Being Drilled at December 31, 2010	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)(3)]	Gross[(1)]	Net[(2)]
Productive Wells								
United States								
Central	3,698	2,116	17	6	3,715	2,122	23	9
Western	1,398	1,024	593	517	1,991	1,541	2	2
Gulf Coast	1,006	804	46	36	1,052	840	10	10
Total	6,102	3,944	656	559	6,758	4,503	35	21
Brazil	9	2	5	2	14	4	2	1

Egypt							4	2
Worldwide Total.	6,111	3,946	661	561	6,772	4,507	41	24

(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, 2010, we operated 4,057 of the 4,507 net productive wells.

Table of Contents

	Net Exploratory[1]			Net Development[1]		
	2010	2009	2008	2010	2009	2008
Wells Drilled						
United States						
Productive	35	61	163	55	69	278
Dry		2	2	2	2	7
Total	35	63	165	57	71	285
Brazil						
Productive					1	
Dry						
Total					1	
Egypt						
Productive						
Dry		2				
Total		2				
Worldwide						
Productive	35	61	163	55	70	278
Dry		4	2	2	2	7
Total	35	65	165	57	72	285

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

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

Net Production, Sales Prices, Transportation and Production Costs

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

	2010	2009	2008
Volumes:			
Consolidated Net Production Volumes			
United States			
Natural gas (MMcf)	215,905	214,718	229,518
Oil, condensate and NGL (MBbls)	5,786	5,548	6,371
Total (MMcfe)	250,621	248,006	267,745
Brazil			
Natural gas (MMcf)	9,706	3,826	3,185
Oil, condensate and NGL (MBbls)	384	100	124

Total (MMcfe)	12,010	4,426	3,928
Consolidated Worldwide			
Natural gas (MMcf)	225,611	218,544	232,703
Oil, condensate and NGL (MBbls)	6,170	5,648	6,495
Total (MMcfe)	262,631	252,432	271,673
Total (MMcfe/d)	720	691	742
Unconsolidated Affiliate Volumes(1)			
Natural gas (MMcf)	17,165	19,557	20,576
Oil, condensate and NGL (MBbls)	937	1,097	1,054
Total equivalent volumes (MMcfe)	22,787	26,139	26,899
MMcfe/d	62	72	74
Total Combined Volumes(1)			
Natural gas (MMcf)	242,776	238,101	253,279
Oil, condensate and NGL (MBbls)	7,107	6,745	7,549
Total equivalent volumes (MMcfe)	285,418	278,571	298,572
MMcfe/d	782	763	816

Table of Contents

	2010	2009	2008
Consolidated Prices and Costs per Unit:			
Natural Gas Average Realized Sales Price ($/Mcf)			
United States			
Physical sales	$ 4.26	$ 3.78	$ 8.51
Including financial derivative settlements	$ 5.71	$ 7.68	$ 8.26
Brazil			
Physical sales	$ 5.65	$ 4.84	$ 2.60
Including financial derivative settlements	$ 4.93	$ 4.22	$ 2.60
Worldwide			
Physical sales	$ 4.32	$ 3.80	$ 8.43
Including financial derivative settlements(2)	$ 5.67	$ 7.62	$ 8.18
Oil, Condensate and NGL Average Realized Sales Price ($/Bbl)			
United States			
Physical sales	$64.99	$47.03	$82.96
Including financial derivative settlements	$63.60	$78.70	$77.42
Brazil			
Physical sales	$78.02	$60.88	$96.21
Including financial derivative settlements	$78.02	$60.88	$96.21
Worldwide			
Physical sales	$65.80	$47.27	$83.21
Including financial derivative settlements(2)	$64.50	$78.38	$77.78
Average Transportation Costs			
United States			
Natural gas ($/Mcf)	$ 0.31	$ 0.28	$ 0.32
Oil, condensate and NGL ($/Bbl)	$ 0.84	$ 0.78	$ 0.98
Worldwide			
Natural gas ($/Mcf)	$ 0.30	$ 0.28	$ 0.31
Oil, condensate and NGL ($/Bbl)	$ 0.79	$ 0.77	$ 0.96
Average Production Costs ($/Mcfe)			
United States			
Lease operating expenses	$ 0.62	$ 0.70	$ 0.89
Production taxes	0.21	0.21	0.44
Total production costs	$ 0.83	$ 0.91	$ 1.33
Brazil			
Lease operating expenses(3)	$ 3.07	$ 5.19	$ 1.64
Production taxes	0.73	0.68	0.58
Total production costs	$ 3.80	$ 5.87	$ 2.22
Worldwide			
Lease operating expenses(3)	$ 0.73	$ 0.78	$ 0.90
Production taxes	0.27	0.22	0.44
Total production costs	$ 1.00	$ 1.00	$ 1.34

(1) Represents our approximate 49 percent equity interest in the volumes of Four Star.

(2) Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Had we included these premiums in our natural gas average realized prices in 2010, our realized price, including financial derivatives settlements, would have decreased by $0.70/Mcf for the year ended December 31, 2010. Premiums related to natural gas derivatives settled during the year ended December 31, 2008 were $21 million. Had we included these premiums in our natural gas average realized prices in 2008, our realized price, including financial derivative settlements, would have decreased by $0.09/Mcf for the year ended December 31, 2008. We had no premiums related to natural gas derivatives settled during the year ended December 31, 2009, or related to oil derivatives settled during the years ended December 31, 2010, 2009 and 2008.

(3) Includes approximately $14 million of start-up costs in Camarupim Field in 2009 or $3.08 per Mcfe for Brazil and $0.05 per Mcfe worldwide.

Table of Contents

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:

	2010	2009	2008
		(In millions)	
United States			
Acquisition Costs:			
Proved	$ 51	$ 87	$ 51
Unproved	269	89	74
Development Costs	276	324	938
Exploration Costs:			
Delay rentals	9	5	6
Seismic acquisition and reprocessing	15	27	24
Drilling	576	323	408
Asset Retirement Obligations	7	36	19
Total full cost pool expenditures	1,203	891	1,520
Non-full cost pool expenditures	35	34	30
Total costs incurred	$ 1,238	$ 925	$ 1,550
Brazil and Egypt[(1)]			
Acquisition Costs:			
Unproved	$	$ 51	$ 1
Development Costs	28	118	93
Exploration Costs:			
Seismic acquisition and reprocessing	6	3	13
Drilling	52	64	91
Asset Retirement Obligations		6	
Total full cost pool expenditures	86	242	198
Non-full cost pool expenditures	1	4	13
Total costs incurred	$ 87	$ 246	$ 211
Worldwide[(1)]			
Acquisition Costs:			
Proved	$ 51	$ 87	$ 51
Unproved	269	140	75
Development Costs	304	442	1,031
Exploration Costs:			
Delay rentals	9	5	6
Seismic acquisition and reprocessing	21	30	37
Drilling	628	387	499
Asset Retirement Obligations	7	42	19
Total full cost pool expenditures	1,289	1,133	1,718
Non-full cost pool expenditures	36	38	43

Total costs incurred	$ 1,325	$ 1,171	$ 1,761

(1) Costs incurred for Egypt were $20 million, $81 million and $27 million for the years ended December 31, 2010, 2009 and 2008.

Table of Contents

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. These long-term contracts include a gas sales agreement and a condensate sales agreement. 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. 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 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, completion and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in this 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 various governmental safety and environmental 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 Office of Natural Resources Revenue within the Department of Interior, 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 El Paso 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, 2010, 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 production levels of our Exploration and Production segment, 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, 2010:

	Affiliated Pipelines[1]	Other Pipelines
Daily capacity (MMBtu/d)	526,000	253,000
Expiration	2011 to 2028	2011 to 2026
Receipt points / Delivery points	Various	Various

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

Legacy natural gas and power contracts. As of December 31, 2010, we had several physical natural gas contracts with power plants associated with our legacy trading activities. These contracts obligate us to sell gas to these plants and have various expiration dates ranging from 2012 to 2028 with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 130,000 MMBtu/d. These natural gas supply contracts had associated transportation volumes and costs which are included in our transportation-related contracts above.

In addition, we had power contracts that require us to swap locational differences in power prices between three power plants in Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub. 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. We have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

Markets, Competition and Regulatory Environment

Our Marketing segment operates in a highly competitive environment, competing on the basis of price, 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 (CFTC).

Environmental

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

Employees

As of February 21, 2011, we had 4,937 full-time employees, of which 91 employees are subject to collective bargaining arrangements.

Table of Contents

Executive Officers of the Registrant

Our executive officers as of February 25, 2011, are listed below.

Name	Office	Officer Since	Age
Douglas L. Foshee	Chairman, President and Chief Executive Officer of El Paso	2003	51
John R. Sult	Executive Vice President and Chief Financial Officer of El Paso	2005	51
Brent J. Smolik	Executive Vice President of El Paso and President of El Paso Exploration & Production Company	2006	49
James C. Yardley	Executive Vice President, Pipeline Group	2005	59
D. Mark Leland	Executive Vice President of El Paso and President of Midstream Group	2005	49
Robert W. Baker	Executive Vice President and General Counsel of El Paso	2002	54
Susan B. Ortenstone	Executive Vice President and Chief Administrative Officer of El Paso	2003	54
James J. Cleary	President of Western Pipeline Group	2005	56
Dane E. Whitehead	Senior Vice President, Strategy and Enterprise Business Development of El Paso	2009	49

Douglas L. Foshee has been Chairman of the Board of Directors of El Paso Corporation since May 2009 and 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. Several subsidiaries of Halliburton, including DII Industries and Kellogg Brown & Root, commenced prepackaged Chapter 11 proceedings to discharge current and future asbestos and silica personal injury claims in December 2003 and an order confirming a plan of reorganization became final effective December 31, 2004. 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 from January 2009 until February 2010 served as a trustee of AIG Credit Facility Trust. 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 various other civic and community organizations. Mr. Foshee also serves on the board of directors of El Paso Pipeline GP Company, L.L.C., general partner of El Paso Pipeline Partners, L.P..

John R. Sult has been Executive Vice President and Chief Financial Officer of El Paso Corporation since March 2010 and Senior Vice President and Chief Financial Officer from November 2009 to March 2010. Mr. Sult previously served as Senior Vice President and Controller of El Paso from November 2005 to November 2009. He has served as Executive Vice President and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. since July 2010, Senior Vice President and Chief Financial Officer from November 2009 to July 2010, and Senior Vice President, Chief Financial Officer and Controller from August 2007 to November 2009. Mr. Sult served as Senior Vice President, Chief Financial Officer and Controller of El Paso s Pipeline Group from November 2005 to November 2009. Mr. Sult was Vice President and Controller for Halliburton Energy Services from August 2004 to October 2005. Mr. Sult also serves on the board of directors 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 Corporation 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, America s Natural Gas Alliance and the Independent Petroleum Association of America.

James C. Yardley has been Executive Vice President of El Paso Corporation with responsibility for the regulated pipeline business unit since August 2006. He has served as Chairman of the Board of Tennessee Gas Pipeline Company since February 2007 and served as its President from August 2006 to August 2010. Mr. Yardley has been Chairman of El Paso Natural Gas Company since August of 2006 and served as President of Southern Natural Gas Company from May 1998 to August 2010. 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 also serves on the board of Interstate Natural Gas Association of America and previously served as its Chairman. 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..

D. Mark Leland has been Executive Vice President of El Paso Corporation and President of El Paso s Midstream business unit since October 2009. Mr. Leland previously served as Executive Vice President and Chief Financial Officer of El Paso from August 2005 to November 2009. He served as Executive Vice President of El Paso Exploration & Production Company from January 2004 to August 2005, and as Chief Financial Officer and a director from April 2004 to August 2005. Mr. Leland served as Senior Vice President and Chief Operating Officer of GulfTerra Energy Partners, L.P. and its general partner from January 2003 to December 2003, and as Senior Vice President and Controller from July 2000 to January 2003. 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 Corporation 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. Mr. Baker previously served as Senior Vice President and Deputy General Counsel of El Paso from January 2002 to February 2003. Prior to that time, he held various legal positions with El Paso and its subsidiaries, including managing the legal matters associated with telecommunication services, domestic power plant development, and the international energy infrastructure projects. 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..

Susan B. Ortenstone has been Executive Vice President and Chief Administrative Officer of El Paso Corporation since March 2010 and Senior Vice President and Chief Administrative Officer from October 2007 to March 2010. Ms. Ortenstone previously served as Senior Vice President from October 2003 to October 2009. Ms. Ortenstone was Chief Executive Officer for Epic Energy Pty Ltd. from January 2001 to June 2003. Ms. Ortenstone serves as Executive Vice President 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. 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..

Dane E. Whitehead has been Senior Vice President of Strategy and Enterprise Business Development of El Paso Corporation since October 2009. Mr. Whitehead previously served as Senior Vice President and Chief Financial Officer for El Paso Exploration & Production Company from May 2006 to October 2009. From October 1993 to April 2006, Mr. Whitehead held various positions at Burlington Resources Inc. including serving as Vice President, Controller and Chief Accounting Officer.

Available Information

Our website is http://www.elpaso.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the Securities and Exchange Commission (SEC). 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 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 such variances can be material. Where we 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. The words believe, expect, estimate, anticipate and similar expressions will generally identify forward-looking statements. All our forward-looking statements, whether written or oral, are expressly qualified by these and other cautionary statements. We disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date provided. 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 of our forward-looking statements. If any of the following risks were actually to occur, our business, results of operations, financial condition and growth could be materially adversely affected. In that case, the value of our debt and equity securities could decline materially.

Common Risks Related to All of Our Businesses

The supply and demand for oil, natural gas and NGLs could be adversely affected by many factors outside of our control which could negatively affect us.

Our success depends on the supply and demand for oil, natural gas and NGLs. The degree to which each of our businesses is impacted by changes in supply or demand varies. For example, our pipeline business is not as significantly impacted as our other businesses in the short-term by reductions in the supply or demand for natural gas since our pipelines recover most of their revenues from reservation charges under longer-term contracts that are not dependent on the supply and demand of natural gas in the short-term. However, all of our businesses can be negatively impacted by sustained downturns in supply and demand for oil, natural gas or NGLs. One of the major factors that will impact natural gas demand will be the potential growth of natural gas in the power generation market, particularly driven by the speed and level of existing coal-fired power generation that is replaced with natural gas-fired power generation. In addition, the supply and demand for oil, natural gas and NGLs for our businesses will depend on many other factors outside of our control, which include, among others:

- Adverse changes in global economic conditions, including changes that negatively impact general demand for oil and its refined products; power generation and industrial loads for natural gas; and petrochemical, refining and heating demand for NGLs.

- Adverse changes in geopolitical factors, including the ability of the Organization of Petroleum Exporting Countries (OPEC) to agree upon and maintain certain production levels, political unrest and changes in foreign governments in producing regions of the world and unexpected wars, terrorist activities and others acts of aggression;

- Technological advancements that may drive further increases in production from oil and natural gas shales;

- The need of many producers to drill to maintain leasehold positions regardless of current prices;

- The oversupply of NGLs that may be caused by the wider spread between oil and natural gas prices;

- Competition from imported LNG and Canadian supplies and alternate fuels;

- Increased prices of oil, natural gas or NGLs that could negatively impact the demand for these products;

Increased costs to explore for, develop, produce, gather, process and transport oil, natural gas or NGLs, including increases in oil field service costs;

Adoption of various energy efficiency and conservation measures; and

Perceptions of customers on the availability and price volatility of our products, particularly customers perceptions on the volatility of natural gas prices over the longer-term.

Table of Contents

The prices for oil, natural gas and NGLs could be adversely affected by many factors outside of our control which could negatively affect us.

Our success depends upon the prices we receive for our oil, natural gas and NGLs. Oil, natural gas and NGL prices historically have been volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. There is a risk that commodity prices will remain depressed for sustained periods, especially in relation to natural gas prices which are at relatively low levels at this time. The degree to which each of our businesses is impacted by lower commodity prices varies. For example, our pipeline business is not as significantly impacted in the short-term by changes in natural gas prices as our other businesses. Subject to our risk mitigation and hedging strategies for our other businesses, our exploration and production and midstream businesses are more likely to be impacted by short-term changes in commodity prices. However, all of our businesses can be negatively impacted in the long-term by sustained depression in commodity prices for oil, natural gas or NGLs, including reductions in (a) our ability to renew pipeline transportation contracts on favorable terms, as well as to construct new pipeline and processing infrastructure and (b) our drilling opportunities in our exploration and production business. The prices for oil, natural gas and NGLs are subject to a variety of additional factors that are outside of our control, which include, among others:

- Changes in regional, domestic and international supply and demand;
- Volatile trading patterns in commodity-futures markets;
- Changes in basis differentials among different supply basins that can negatively impact our ability to compete with supplies from other basins, including our ability to maintain pipeline transportation revenues and renew transportation contracts in supply basins that are not as competitive as other alternatives
- Changes in the costs of exploring for, developing, producing, transporting, processing and marketing each of these products;
- Increased federal and state taxes, if any, on the sale or transportation of oil, natural gas and NGL;
- The price and availability of supplies of alternative energy sources; and
- The amount of capacity available to gather, process and transport our products out of our production areas to more liquid points of delivery and sale.

In addition to negatively impacting our cash flows, prolonged or substantial declines in these commodity prices can negatively impact our estimated proven oil and natural gas reserves which can cause us to incur non-cash charges to earnings. The majority of our proved reserves at December 31, 2010 are natural gas and, as a result we are substantially more sensitive to changes in natural gas prices than to changes in oil and NGL prices. In addition, such decreases in commodity prices could negatively impact the amount of oil and natural gas production that we can produce economically in the future. On the other hand, increases in these commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in such commodity prices.

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

We use futures, over-the-counter options and swaps to mitigate our commodity price, basis, currency and interest rate exposures. However, we do not typically hedge all of these exposures. For example, we do not typically hedge positions beyond several years with regard to commodity or basis risks. As a result, we are subject to commodity price and basis exposure, particularly in our exploration and production business that has a multi-year inventory of proved reserves and unproved resources.

Most of the hedges we enter into to mitigate commodity price risk are not designated as accounting hedges and are therefore marked to market. As a result, we still experience volatility in our revenues and net income as a result of changes in commodity prices, counterparty non-performance risks, correlation factors and changes in the liquidity of the market. Furthermore, the valuation of these financial instruments involves estimates that are based on assumptions that could prove to be incorrect and result in financial losses. Although we have internal controls in place that impose restrictions on the use of derivative instruments, there is a risk that such controls will not be complied with or will not be effective and we could incur substantial losses on our derivative transactions. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital and liquidity when commodity prices or interest rates change. The potential impact of the recent federal legislation

33

regulating derivative transactions on our collateral posting requirements is not certain at this time and we could be required to post additional collateral as a result of the implementing regulations.

To the extent we enter into derivative contracts to manage our commodity price exposure, basis and interest rate exposures, we forego the benefits we could otherwise experience if such prices, differentials or rates were to change favorably. In addition, when we enter into fixed price derivative contracts, we could experience losses and be required to pay cash to the extent that commodity prices, basis positions or interest rates were to increase above the fixed price.

Our businesses are subject to competition from third parties which could negatively affect us.

The oil, natural gas and NGL businesses are highly competitive. In our pipeline business, we compete with other interstate and intrastate pipeline companies as well as gatherers and storage companies in the transportation and storage of natural gas. We also compete with suppliers of alternate sources of energy, including electricity, coal and fuel oil. We frequently have one or more competitors in the supply basins and markets that we are connected to. This includes new large pipeline systems that have recently been constructed from supply basins in which one or more of our pipelines are located (including the Bison and Rockies Express pipeline systems) and growing competition in many of the markets that we serve, including many of the markets in the northeast and southwest (including Transwestern s pipeline into Phoenix). There have also been various proposals over time to construct LNG terminals along the east and west coasts that could also negatively impact the demand and the transportation rates that several of our pipeline systems could charge to the extent the LNG terminals were constructed. For example, our EPNG system experienced a loss of demand when an LNG terminal was completed south of the Mexico California border.

In our exploration and production business, we compete with third parties in the search for and acquisition of leases, properties and reserves, as well as the equipment, materials and services required to explore for and produce our reserves. There has been intense competition for the acquisition of leasehold positions, particularly in many of the oil and natural gas shale plays. Our competitors include the major and independent natural gas and oil companies, foreign banks and oil companies and individual producers, many of which have financial and other resources that are substantially greater than those available to us. Similarly, we compete with many third parties in the sale of oil, natural gas and NGLs to customers, some of which have substantially larger market positions, marketing staff and financial resources than us.

In our new midstream business, we compete with third parties to gather, transport, process, fractionate, store or handle hydrocarbons. Although we attempt to leverage the synergies between our pipeline and exploration and production businesses, most of these third parties have existing facilities and as a result have more scale and personnel than us. Therefore, there can be no assurances regarding our successful re-entry into the midstream business, including our ability to compete for individual projects.

Our operations are subject to operational hazards and uninsured risks which could negatively affect us.

Our operations are subject to a number of inherent risks including fires, earthquakes, adverse weather conditions (such as extreme cold or heat, hurricanes, tornadoes, lightning and flooding) and other natural disasters; terrorist activity or acts of aggression; the collision of equipment of third parties on our infrastructure (such as damage caused to our underground pipelines by third party excavation or construction); explosions, pipeline failures, mechanical and process safety failures, well blowouts, formations with abnormal pressures and collapses of wellbore casing or other tubulars; events causing our facilities to operate below expected levels of capacity or efficiency; uncontrollable flows of natural gas, oil, brine or well fluids, release of pollution or contaminants into the environment (including discharges of toxic gases or substances) and other environmental hazards. Each of these risks could result in (a) damage or destruction of our facilities, (b) damages and injuries to persons and property or (c) business interruptions while damaged energy infrastructure is repaired or replaced, each of which could cause us to suffer substantial losses. Our offshore operations may encounter additional marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, and governmental regulations (including interruption or termination of drilling rights by governmental authorities based on environmental, safety and other considerations). In addition, although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns as a result of global emissions of greenhouse gas (GHG) could have a negative impact upon our operations in the future, particularly with regard to any of our facilities that are located in or near the Gulf of Mexico and other coastal regions.

While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels, limits on our maximum recovery and do not cover all risks. For example, we do not carry or are unable to obtain insurance coverage on terms that we find acceptable for certain exposures including, but not limited to certain environmental exposures (including potential environmental fines and penalties), business interruption, named windstorm / hurricane exposures and, in limited circumstances, certain political risk exposure. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their coverage obligations. As a result, we could be adversely affected if a significant event occurs that is not fully covered by insurance.

Certain of our business operations are subject to joint ventures or operations by third parties, which could negatively impact our control and operation of these operations.

Some of our pipeline and exploration and production business operations and interests are either subject to joint ventures or are operated by other companies. The most significant of these are our equity interest in Citrus Corporation (and its Florida Gas operations) and GLNG in our pipeline segment, our equity interest in Four Star in our exploration and production segment and our equity interest in our midstream business. Although we operate the substantial majority of the properties in our exploration and production business, certain of the properties are operated by third party working interest owners. In certain cases, (a) we have limited ability to influence or control the day to day operation of such properties, including compliance with environmental, safety and other regulations, (b) we cannot control the amount of capital expenditures that we are required to fund with respect to these properties, (c) we are dependent on third parties to fund their required share of capital expenditures and (d) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets. In addition, we depend on third parties to gather, store and transport natural gas upstream or downstream of the assets or facilities of our businesses. If these third party facilities were to become unavailable or reduced for any reason, then revenues generated from our assets and facilities that utilize them could be negatively impacted.

We are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.

Our operations are subject to a complex set of federal, state and local laws and regulations that tend to change from time to time and generally are becoming increasingly more stringent. In addition to laws and regulations affecting our individual business units, there are various laws and regulations that regulate various market practices in the industry, including antitrust laws and laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission (FTC), FERC and CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years. In addition, all of our businesses are subject to laws and regulations that govern environmental, health and safety matters. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, as well as regulations designed for the protection of human health and safety and threatened or endangered species. Compliance obligations can result in significant costs to install and maintain pollution controls, and to maintain measures to address personal and process safety and protection of the environment and animal habitat near our operations. We are often obligated to obtain permits or approvals in our operations from various federal, state and local authorities, which permits and approvals can be denied or delayed. In addition, we are exposed to fines and penalties to the extent that we fail to comply with the applicable laws and regulations, as well as the potential for limitations to be imposed on our operations. These regulations often impose remediation obligations associated with the investigation or clean-up of contaminated properties, as well as damage claims arising out of the contamination of properties or impact on natural resources. Finally, many of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we operate assets that are located on federal lands located both onshore and offshore, which are regulated by the Department of the Interior, particularly by the Bureau of Land Management (BLM) and the Bureau of Ocean Energy Management, Regulation and Enforcement. We also have pipeline and exploration and production operations on Native American tribal lands, which are regulated by the Department of the Interior, particularly by the Bureau of Indian Affairs, as well as local tribal authorities. Operations on these properties are often subject to additional regulations and compliance obligations, which can delay our access to such lands and impose additional compliance costs.

Table of Contents

The laws and regulations (and the interpretations thereof) that are applicable to our businesses could materially change in the future and increase the cost of our operations or otherwise negatively impact us.

The regulatory framework affecting our businesses is frequently subject to change, with the risk that either new laws and regulations may be enacted or existing laws and regulation may be amended. Such new or amended laws and regulations can materially affect our operations and our financial results. In this regard, there have been proposals to implement or amend federal, state, local and tribal laws and regulations that could negatively impact our businesses, which includes among others:

Climate Change and other Emissions. There have been various legislative and regulatory proposals at the federal and state levels to address climate change and to regulate GHG emissions. The Environmental Protection Agency (EPA) and several state environmental agencies have already adopted regulations to regulate GHG emissions. Although natural gas as a fuel supply for power generation has the least GHG emissions of any fossil fuel, it is uncertain at this time what impact the existing and proposed regulations will have on the demand for natural gas and on our operations. This will largely depend on what regulations are ultimately adopted, including the level of any emission standards; the amount and costs of allowances, offsets and credits granted; and incentives and subsidies provided to other fossil fuels, nuclear power and renewable energy sources. Although the EPA has adopted a tailoring rule to regulate GHG emissions, it is not expected to materially impact our operations until 2016. However, the tailoring rule is subject to judicial reviews and such reviews could result in the EPA being required to regulate GHG emissions at lower levels that could subject many of our larger facilities to regulation prior to 2016. There have also been various legislative and regulatory proposals at the federal and state levels to address various emissions from coal-fired power plants. Although such proposals will generally favor the use of natural gas fired power plants over coal-fired power plants, it remains uncertain what regulations will ultimately be adopted and when they will be adopted. Finally, there have been other various environmental regulatory proposals that could increase the cost of our environmental liabilities as well as increase our future compliance costs. For example, the EPA has proposed more stringent ozone standards, as well as implemented more stringent emission standards with regard to certain combustion engines on our pipeline systems. It is uncertain what impact new environmental regulations might have on us until further definition is provided in the various legislative, regulatory and judicial branches. In addition, any regulations would likely increase our costs of compliance by requiring us to monitor emissions, install additional equipment to reduce carbon emissions and possibly to purchase emission credits, as well as potentially delay the receipt of permits and other regulatory approvals. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance in the rates charged by our pipelines and in the prices at which we sell oil, natural gas and NGLs, 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.

Renewable / Conservation Legislation. There have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (a) shift more power generation to renewable energy sources and (b) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGL consumption and thus have negative impacts on our operations and financial results.

E&P Safety. Partially as a result of a recent explosion on an offshore platform of a third party and subsequent release of oil into the Gulf of Mexico, there have been various regulations proposed and implemented that could materially impact the costs of exploration and production operations, as well as cause substantial delays in the receipt of regulatory approvals from both an environmental and safety perspective. Although our presence offshore has been greatly reduced (including having no operations in the deepwater), such proposed and implemented regulations could impact our remaining exploration and production operations in the Gulf of Mexico. It is also possible that similar, more stringent, regulations might be enacted or delays in receiving permits may occur in other areas, such as in offshore regions of other countries (such as Brazil) and in other onshore regions of the United States (including drilling operations on other federal or state lands). There have also been more stringent proposals in various regions of the U.S. with regard to water usage and disposal in our businesses that could also negatively affect our operations.

Pipeline Safety. Various legislative and regulatory reforms associated with pipeline safety and integrity issues have been recently proposed, including reforms that would require increased periodic inspections, installation of additional valves and other equipment on our pipelines and subjecting additional pipelines (including gathering and intrastate pipeline facilities) to more stringent regulation. It is uncertain what reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results.

Hydraulic Fracturing. Hydraulic fracturing is a process commonly used to stimulate the recovery of production from shale formations, tight sands, coal bed methane and other unconventional reservoirs. Hydraulic fracturing has primarily been regulated at the state level through permitting and compliance requirements. Various federal and state laws and regulations have been proposed to impose more stringent regulation of the hydraulic fracturing process, as well as to require additional disclosures regarding the chemicals used in the process. Such laws and regulations if adopted could impose additional costs in our operations, as well as cause significant delays in obtaining regulatory approvals to drill and complete wells. In addition, there have been proposals to restrict certain buyers from purchasing natural gas and oil produced from wells that have utilized hydraulic fracturing in their completion process, which could negatively impact our ability to sell our production from wells that utilized these fracturing processes.

Derivatives. Federal legislation was enacted in 2010 to impose additional regulation on derivative transactions. The CFTC is in the process of adopting implementing regulations, including the creation of position limits and certain exemptions from the general requirement that swap transactions be cleared through a central exchange for which collateral must be posted. Although we do not currently expect that such regulations will have a material adverse impact on us, the regulations have not been finalized and there is a risk that the regulations ultimately adopted might negatively impact our marketing activities as well as our hedging activities. For example, the proposed regulations currently would not require collateral to be posted for our hedging transactions by either us or our counterparties, which are often financial institutions. However, if we were required to post collateral for our hedging transactions in the future either pursuant to the final regulations that are adopted or by our counterparties, then it would (a) negatively impact our liquidity and reduce cash available for capital expenditures and/or (b) reduce our ability to enter into hedges to reduce our commodity price exposure thereby making our results of operation more volatile and our cash flows less predictable. In addition, the new regulations could also significantly reduce the availability of counterparties and derivatives, increase the costs of derivatives that are available and negatively alter the terms of the derivative contracts.

Tax Policies. Various federal legislation has been proposed to materially revise the tax provisions associated with the energy industry. For example, proposed changes include (a) elimination of current deductions for intangible drilling and development costs, (b) the repeal of the percentage depletion allowance for oil and gas properties, (c) implementation of certain international tax reforms, (d) repeal of the manufacturing tax deduction for oil and natural gas companies, (e) an increase in the geological and geophysical amortization period for independent producers and (f) taxation of carried interests, including potential taxation of earnings at EPB. Although we are less impacted by such proposals than many of our peers due to our net operating loss position, any such proposals if implemented could have a negative impact on our financial results and results for operations, as well as deplete our net operating loss position sooner than expected. There have also been proposals to simplify the tax code by generally eliminating deductions and reducing the effective corporate and individual tax rates, which could negatively impact the tax allowance in our FERC-approved pipeline rates and impact the return and yield expectations of our investors and the investors of EPB. It is unclear whether these or other changes will be enacted and if enacted when they will become effective. Any such changes could negatively affect us.

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

We are subject to the risk that our counterparties fail to make payments to us within the time required under our contracts. Our current largest exposures are associated with shippers under long-term transportation contracts on our pipeline systems and with some of our hedging transactions. Our credit procedures and policies may not be adequate to fully eliminate counterparty credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future counterparties fail to pay and/or perform, we could be adversely affected. For example, with respect to our pipeline and midstream businesses, we may not be able to effectively remarket capacity or enter into new contracts at similar terms during and after insolvency proceedings involving a customer.

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

As an owner of large energy infrastructure facilities with significant capital expenditures in each of our businesses, we rely on contractors for certain construction, drilling and completion operations and we rely on suppliers for key materials, supplies and services, including steel mills, pipe and tubular manufacturers and oil field service providers. 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, including their performance and warranty obligations. This could result in delays or defaults in performing such contractual obligations and increased costs to seek replacement contractors, each which could adversely impact us.

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

Our businesses require the retention and recruitment of a skilled workforce including engineers, technical personnel and other professionals. We compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible, which have significant institutional knowledge that must be transferred to other employees. If we are unable to (a) retain our current employees, (b) successfully complete our knowledge transfer and/or (c) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Risks Related to Our Pipeline Business

The success of our pipeline business depends on many factors beyond our control.

The results of our pipeline business are impacted in the long term by the volumes of natural gas we transport or store and the prices we are able to charge for these services. The volumes we transport and store depend on the actions of third parties that are based on factors beyond our control. Such factors include events that negatively impact our customers demand for natural gas and could expose our pipelines to the risk that we will not be able to renew contracts at expiration or that we will be required to discount our rates significantly upon renewal. In addition, some of our pipeline systems and expansion projects are not currently fully subscribed. For example, our Ruby and FGT Phase VIII projects are not currently fully subscribed and there is a risk that we will not be able to obtain additional customer commitments, that additional customer commitments will be delayed or that additional commitments will only be obtained at reduced rates. We are also highly dependent on our customers and downstream pipelines to attach new and increased loads on their systems in order to grow our pipeline businesses. Further, state agencies that regulate our pipelines local distribution company customers could impose requirements that could impact demand for our pipelines services.

The volume of gas that we transport and store also depends on the availability of natural gas supplies that are attached to our pipeline systems, including the need for producers to continue to develop additional gas supplies to offset the natural decline from existing wells connected to our systems. This requires the development of additional natural gas reserves, obtaining additional supplies from interconnecting pipelines, and the development of LNG facilities on or near our systems. There have been major shifts in supply basins over the last few years, especially with regard to the development of new natural gas shale plays and declining production from conventional sources of supplies as well as declining deliveries from Canada. A prolonged 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.

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

Our pipeline businesses are extensively regulated by the FERC, the U.S. Department of Transportation, the U.S. Department of Interior, the U.S. Coast Guard, the U.S. Department of Homeland Security and various state and local regulatory agencies whose actions have the potential to adversely affect our profitability. FERC regulates most aspects of our business, including the terms and conditions of services offered, our relationships with affiliates, construction and abandonment of facilities and the rates charged by our pipelines (including establishing authorized rates of return). Our pipelines periodically file to adjust their rates charged to their customers. Three of our pipeline systems have filed or will file rate cases that will establish new rates in 2011. There is a risk that the FERC may establish rates that are not acceptable to us or have a negative impact on us. In addition, the profitability of our pipeline systems is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. Our operating results can be negatively impacted to the extent that such costs increase in an amount greater than what we are permitted to recover in our rates or to the extent that there is a lag before the pipeline can file and obtain rate increases.

Our existing rates may also be challenged by complaint. The FERC commenced several proceedings in 2009 and 2010 against unaffiliated pipeline systems to reduce the rates they were charging their customers. There is a risk that the FERC or our customers could file similar complaints on one or more of our pipeline systems and that a successful complaint against our pipelines rates could have an adverse impact on us.

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 could result in lower recourse rates that could negatively impact our investment in EPB.

Certain of our pipeline systems transportation services are subject to negotiated rate contracts that may not allow us to recover our costs of providing the services.

Under FERC policy, interstate pipelines and their customers may execute contracts at a negotiated rate which may be above or below the FERC regulated recourse rate for that service. These negotiated rate contracts are generally not subject to adjustment for increased costs which could occur due to inflation, increases in the cost of capital or taxes or other factors relating to the specific facilities being used to perform the services. It is possible that costs to perform services under negotiated rate contracts will exceed the negotiated rates. Any shortfall of revenue, representing the difference between recourse rates and negotiated rates could result in either losses or lower rates of return in providing such services.

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

Substantially all of our pipeline 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 example, basis differentials between receipt and delivery points on our pipeline systems could decrease over time and thereby negatively impact our ability to renew contracts at rates that were previously in place. Our ability to extend and replace contracts could be adversely affected by factors we cannot control, as discussed above. In addition, changes in state regulation of local distribution companies may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire.

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

We frequently 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 from the FERC and other regulatory agencies on a timely basis that are on terms that are acceptable to us, including the potential negative impact of delays and increased costs caused by general opposition to energy infrastructure development, especially in environmentally, culturally sensitive and more heavily populated areas;

- 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;

Impediments on our ability to acquire rights-of-way or land rights on terms that are acceptable to us;

Our ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from weather conditions, geologic conditions, inflation or increased costs of equipment, materials (such as steel and nickel), labor, contractor productivity, delays in construction due to various factors including delays in obtaining regulatory approvals or other factors beyond our control. These cost overruns could be material and we may not be able to recover such excess costs from our customers which could negatively impact the return on our investments or could result in financial impairments;

Our ability to construct projects within anticipated time frames that would likely delay our collection of transportation charges under our contracts;

The failure of suppliers and contractors to meet their performance and warranty obligations; 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 a downturn in the economy and its negative impact upon natural gas demand may result in either slower development in the potential for future 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.

Our pipeline systems depend on certain key customers and producers for a significant portion of their revenues and the loss of any of these key customers could result in a decline in our revenues.

Our systems rely on a limited number of customers for a significant portion of our systems revenues. For the year ended December 31, 2010, although there is not substantial overlap of the customers of our different pipeline systems, the four largest natural gas transportation customers for each of TGP, CIG, EPNG and SNG accounted for approximately 24 percent, 59 percent, 48 percent and 45 percent of their respective operating revenues. The loss of any material 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 us.

The costs to maintain, repair and replace our pipeline systems may exceed our expected levels.

Much of our pipeline infrastructure was originally constructed many years ago. The age of these assets may result in them being more costly to maintain and repair. We may also be required to replace certain facilities over time. In addition, our pipeline assets may be subject to the risk of failures or other incidents due to factors outside of our control (including due to third party excavation near our pipelines, unexpected degradation of our pipelines, as well as design, construction or manufacturing defects) that could result in personal injury, including death, or property damages. Much of our pipeline systems are located in populated areas which increases the level of such risks. Such incidents could also result in unscheduled outages or periods of reduced operating flows which could result in a loss of our ability to serve our customers and a loss of revenues. Although we are targeted to complete our pipeline integrity program which includes the development and use of in-line inspection tools in high consequence areas by its required completion date at the end of 2012, we will continue to incur substantial expenditures beyond 2012 relating to the integrity and safety of our pipelines. In addition, as indicated above there is a risk that new regulations associated with pipeline safety and integrity issues will be adopted that could require us to incur additional material expenditures in the future.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located. We are subject to the risk that we do not have valid rights-of-way, that such rights-of-way may lapse or terminate, our facilities may not be properly located within the boundaries of such rights-of-way or the landowners otherwise interfere with our operations. Our loss of or interference with these rights could have a material adverse effect on us.

There are accounting principles that are unique to regulated interstate pipeline assets that could materially impact our recorded earnings.

Accounting policies for FERC regulated pipelines are in certain instances different from GAAP principles for nonregulated entities. For example, FERC accounting policies permit certain regulatory assets to be recorded on our balance sheet that would not typically be recorded under GAAP for nonregulated entities. In determining whether to account for regulatory assets on each of our pipelines, we consider various factors including regulatory changes and the impact of competition to determine the probability of recovery of these assets. Currently, all of our pipeline systems have regulatory assets recorded on their balance sheets. If we determine that future recovery is no longer probable for any of our pipeline systems, then we could be required to write off the regulatory assets in the future. In addition, we capitalize a carrying cost (AFUDC) on equity funds related to our construction of long-lived assets. Equity amounts capitalized are included as other non-operating income on our income statement. To the extent that one of our pipeline expansion projects is not fully subscribed when it goes into service, we may experience a reduction in our earnings once the pipeline is placed into service. Currently, our Ruby Pipeline and FGT Phase VIII projects are not fully subscribed and therefore we may experience a reduction in earnings at the pipeline subsidiary levels when they go into service and may negatively impact our return on investment.

Risks Related to Our Exploration and Production Business

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

We have a reserve base that is depleted as it is produced. Unless we successfully replace the reserves that we produce, our reserves will decline which will eventually result in a decrease in oil and natural gas 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. If we do not continue to make significant capital expenditures (such as if our access to capital resources becomes 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 us. In addition, we have certain areas in which we have incurred material costs to explore for and develop reserves. 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 from our full cost pool amortization base on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. We have incurred unevaluated capitalized costs associated with development and exploration activities in Brazil and Egypt for which we have no proven reserves recorded at this time. 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.

Our natural gas and oil drilling and producing operations involve many risks and our production forecasts may differ from actual results.

Our success will depend on our drilling results. Our drilling operations are subject to the risk (a) that we may not encounter commercially productive reservoirs or (b) if we encounter commercially producible reservoirs, that we either may not fully recover our investments or that our rates of return will be less than expected. We are also subject to the risk that we encounter unexpected drilling conditions. Our past performance should not be considered indicative of future drilling performance. For example, we have recently acquired acreage positions in two new oil and natural gas shale areas for which we plan to incur substantial capital expenditures over the next several years. It remains uncertain whether we will be successful in exploring for the reserves in these regions or in developing the reserves that are found. Our success in such areas will depend in part on our ability to successfully transfer our experiences from existing areas into these new shale plays. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different than actual results and such differences could be material.

Table of Contents

The success of our exploration and production business is dependent on many other factors, many of which are outside of our control.

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

- The existence of commodity prices that permit us to earn an acceptable return on our capital expended and to continue existing production, rather than shutting in our production;
- Our ability to expand our leased land positions in desirable areas, which often is subject to intense competition from other companies;
- Our ability to successfully integrate acquisitions;
- The availability of rigs, equipment, supplies and personnel on commercially reasonable terms, particularly with regard to specialty rigs and services such as horizontal rigs and hydraulic fracturing services that are required for many of our unconventional drilling programs;
- Our ability to locate joint working interest owners to assist in funding and enhancing the value of the development of certain of areas such as our Eagle Ford shale acreage;
- Our ability to obtain timely construction of gathering and pipeline infrastructure to attach our production to markets, as well as our ability to obtain transportation free of any interruptions in service by the parties that we have contracted with to gather, process and transport our production;
- Our ability to obtain increased refining capacity for our Altamont oil production, for which there is currently limited capacity to refine the higher degree of wax content contained in the production by us and other producers in the area;
- 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, limit or restrict the use of hydraulic fracturing in our drilling operations, limit or restrict our access to water rights (including disposal of water and other fluids in our operations), reduce operational flexibility, or increase capital and operating costs;
- Governmental action affecting the profitability of our exploration and production activities, such as increased royalties and taxes, as well as the withdrawal of tax incentives for exploration and development activity;
- Our ability to receive certain government approvals or permits on a timely basis on terms acceptable to us, including environmental approvals for our Pinauna project in Brazil;
- Title problems and landowner disputes restricting access to our drilling operations;
- Our lack of control over jointly owned properties and properties operated by others; and
- Continued access to sufficient capital at reasonable rates to fund drilling programs, especially in periods of prolonged economic decline and/or low commodity prices when we may be unable to access the capital markets.

Certain of our undeveloped leasehold acreage is subject to leases that will expire in several years unless production is established on units containing the acreage.

Although most of our reserves are located on leases that are held by production, we do have obligations in many of our leases that provide for the expiration of the lease unless certain conditions are met, such as drilling has not commenced on the lease or production in paying quantities is not obtained within a defined time period. If commodity prices remain low or we are unable to fund our anticipated capital program, including our ability to obtain partners in certain of our operating areas, there is a risk that some of our existing proved reserves and some of our unproved inventory could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in a reduction in our reserves and our growth opportunities and therefore negatively impact our financial results.

Estimating our reserves involves uncertainty, our actual reserves will likely vary from our estimates and negative revisions to our reserve estimates in the future could result decreased earnings, losses and impairments.

All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information was prepared internally and was audited by an independent petroleum consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in these estimates varying considerably from actual results. Estimating quantities of proved reserves is complex and involves significant interpretations and assumptions with respect to available geological, geophysical, and engineering data, including data from nearby producing areas. It also requires us to estimate future economic factors, such as commodity prices, production costs, plugging and abandonment costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial production data, there are greater uncertainties in estimating proved undeveloped reserves and proved developed non-producing reserves. There is also greater uncertainty of estimating proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Furthermore, estimates are subject to revision based upon a number of factors, including many factors beyond our control such as 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.

Therefore, our reserve information represents an estimate and is often different from the quantities of oil and natural gas that are ultimately recovered. The SEC rules require the use of a ten percent discount factor for estimating the value of our future net cash flows from reserves and the use of a 12-month average price. This discount factor may not necessarily represent the most appropriate discount factor, given our costs of capital, actual interest rates and risks faced by our exploration and production business, and the average price will not generally represent the market prices for oil and natural gas over time. Any significant change in commodity prices could cause the estimated quantities and net present value of our reserves to differ and these differences could be material. 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. Finally, 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.

We account for our exploration and production activities under the full cost method of accounting. Changes in the present value of these reserves could result in 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. It could also result in increasing our rates of depreciation, depletion and amortization rates, which could decrease earnings.

A portion of our estimated proved reserves are undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. In addition, as the portion of our proved reserve base that consists of unconventional sources increases, the costs of finding, developing and producing those reserves may require capital expenditures that are greater than more conventional sources. Our estimates of proved reserves assumes that we can and will make these expenditures and conduct these operations successfully. However, future events, including commodity price changes and our ability to access capital markets, may cause these assumptions to change.

Our exploration and production activities are subject to a complex set of regulations that could negatively impact our operations.

Our exploration and production activities are subject to additional regulations that are unique to this business. This includes federal and state regulatory approvals associated with drilling and spacing units, drilling locations, allowable production from wells, unitization or pooling of oil and gas properties, spill prevention plans, limitations on venting or flaring of natural gas and competitive bidding rules on federal and state lands. Generally, the regulations have become more stringent over time and impose more limitations on our operations and cause more costs to be incurred to comply with such increased regulation. Many of these approvals are subject to considerable discretion by the regulatory agencies with respect to the timing and scope of approvals and permits issued. Our inability to obtain these regulatory approvals on terms acceptable to us on a timely basis could have a material negative impact on our operations and financial results.

Risks Related to Our Midstream Business

Our midstream business may be subject to additional risks associated with fluctuations in commodity prices.

The midstream sector generally includes the gathering, transporting, processing, fractionating and storing of natural gas, NGLs and oil. The pricing for each of these products has been volatile over time. In addition, the relative pricing between these products has been volatile, which may affect fractionation spreads and the profitability of the business. Changes in prices and relative price levels may impact demand for products, which in turn may impact the services we provide.

Table of Contents

A decrease in demand for NGL products by the petrochemical, refining or heating industries could affect the profitability of our midstream business.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, could adversely affect the profitability of our midstream business. Various factors impact the demand for NGL products, including general economic conditions, demand by consumers for the end products made with NGL products, extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of NGL processing and transportation capacity, government regulations affecting prices and production levels of natural gas, NGLs or the content of motor fuels.

We will face additional reserve and volumetric risk in our midstream business.

Although the revenues in our pipeline business are typically collected in the form of demand or reservation charges and are not dependent upon reserves or throughput levels, many transactions in the midstream business involve additional reserve and throughput risk. For example, natural gas and oil reserves committed to gathering and processing facilities may not be as large as expected, the life of the reserves may not be as long as expected or the producers may elect not to develop such reserves. We also cannot influence or control the production or the speed of development of the third-party commodities we transport or process. The reserves committed will naturally decline overtime and our ability to attract new reserves in competition with third parties to replace these declining supplies is uncertain. Furthermore, the rate at which production from these reserves declines may be greater than we anticipate. As a result, we may face additional reserve and throughput risk in our midstream business beyond what we typically experience in our pipeline business.

Other Risks Related to Our Businesses, including our Corporate and Legacy Businesses

Our foreign operations and investments involve special risks.

Our activities outside the United States include (a) pipeline and exploration and production projects in Brazil, (b) certain accounts receivables in Brazil associated with our former power business in the country, (c) exploration and production projects in Egypt and (d) a power project in Pakistan. All are subject to the risks inherent in foreign operations and additional risks from assets located in the United States, which include, among others:

- Loss of revenue, property and equipment as a result of hazards such as wars, insurrection, piracy or acts of terrorism;

- Changes in laws, regulations and policies of foreign governments, including changes in the governing parties, nationalization, expropriation, and unilateral renegotiation of contracts by government entities. For example, it is uncertain what effect the political unrest associated with the changes in the governing parties in Egypt will have on our ability to explore for and produce oil and natural gas from our net acreage positions in the country and the value of our investments;

- Difficulties in enforcing rights against government agencies, including being subject to the jurisdiction of local courts in certain instances;

- The effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies, relative inflation risks, and the imposition of foreign exchange restrictions that may negatively impact convertibility and repatriation of our foreign earnings into U.S. dollars;

- Protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations, including those required for the Pinauna project;

- Protracted delays in payments and collections of accounts receivables from state-owned energy companies;

- Transparency and corruption issues, including compliance issues with the U.S. Foreign Corrupt Practices Act, the new United Kingdom bribery laws and other anti-corruption compliance issues; and

Laws and policies of the United States that adversely affect foreign trade and taxation.

As a general rule, we have elected not to carry political risk insurance against these sorts of risks.

We have certain contingent liabilities that could exceed our estimates.

We have certain contingent liabilities associated with litigation, regulatory, environmental and tax matters. In this regard, although we have greatly reduced our litigation, regulatory and environmental exposures over the last several years, we continue to have contingent liabilities (see Part II, Item 8, Financial Statements and Supplementary Data, Note 12). In addition, the positions taken in our federal and state tax returns require significant judgments, use of estimates and interpretation of complex tax laws. Although we believe that we have established appropriate reserves for our litigation and tax matters, we could be required to accrue additional amounts in the future and these amounts could be material.

We have also sold a significant number of assets and either retained certain liabilities or indemnified certain purchasers against future liabilities related to businesses and assets sold, including liabilities associated with environmental, tax, litigation, benefits 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 retained liabilities, including a reduction in historical knowledge of the assets and businesses that is required to effectively manage these liabilities or defend any associated litigation or regulatory proceedings.

The costs of providing pension and post retirement health care plans is subject to factors outside of our control and such costs could increase and could negatively affect our financial results.

Our earnings and cash flows may be impacted by the amount of income or expense we record for our various benefit plan obligations. Our benefit plans include obligations under our defined benefit pension plan and welfare plans for our current employees and medical and life insurance benefits for certain retired employees. Although we believe we have established appropriate reserves for these plans, we could be required to accrue additional liabilities in the future and these amounts could be material. For example, our pension plan was underfunded at December 31, 2010. While we do not currently expect to make additional cash contributions in 2011, we may be required to make additional pension plan contributions in the future. Additionally, our pension plan is supported by assets held in trust that could be negatively impacted by other events, including changes in (a) the value of our assets largely driven by changes in equity and bond markets, (b) the discount rates used to measure pension liabilities and (c) the demographics (including actuarial gains and losses). Although a portion of our postretirement welfare plans are also supported by assets held in a trust, we fund most of our welfare plans on a current basis, including our welfare plan for our current employees and the postretirement welfare plan for certain Case retirees. Medical costs have been generally increasing and such costs could require us to incur additional liabilities and make additional cash expenditures to fund such programs that could have a negative impact on our financial results. Furthermore, the costs of maintaining such welfare plans could be negatively impacted by changes that might arise out of recent health care legislation, the effects of which have not been fully determined at this point. Any of these events, which are beyond our control, could negatively impact us.

We have significant existing debt which requires us to dedicate a substantial portion of our cash flows to service our debt payment obligations, as well as reduces our flexibility to respond to changed circumstances.

We have significant debt, debt service and debt maturity obligations, many of which are more significant than our competitors. This requires us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions or general corporate purposes. In addition, these debt levels expose us to more liquidity and default risks than many of our peers, especially during times of financial volatility and reduced commodity prices. It similarly reduces our flexibility to compete on future projects.

We have significant capital programs in our businesses that require us to access capital markets frequently and any inability to obtain access to the capital markets in the future at competitive rates could have a negative impact on us.

We have extensive capital programs in each of our businesses, which requires us to frequently access the capital markets. Although the markets have become less volatile than they were several years ago, volatility in the financial markets remain. Since we are rated below investment grade at this time, our ability to access the capital markets and the cost of capital could be negatively impacted in the future. This could require us to forego capital opportunities or make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us with investment grade ratings.

Our current and future debt can be negatively impacted by the ratings assigned to our debt facilities, which could have a negative impact upon us.

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, BB- with a stable outlook by Standard & Poor s and BB+ with a stable outlook by Fitch Ratings. These ratings have increased our cost of capital and our operating costs in comparison to many of our peers. There is a risk that these credit ratings may be adversely affected in the future as the credit rating agencies review their general credit requirements as well as review our leverage, liquidity and credit profile. Any reduction in our credit rating could also impact our cost of capital, as well as potentially require us to post additional collateral under certain of our derivative contracts. Any reduction in our credit rating could also negatively impact the credit rating of our subsidiaries, including EPB and one or more of our pipeline subsidiaries, which could also increase their cost of capital. It could also impact our ability, as well as the ability of our subsidiaries, to access the capital markets. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our debt instruments, as well as the market value of our common stock and the units of EPB.

If we are unable to renew our revolving credit facility that expires in November 2012, then it would negatively impact us.

We have a corporate revolving credit facility that is due to expire November of 2012. Prior to maturity, we plan to renew or extend this credit facility. However, many other companies have similar expiration and renewal requirements and we will be competing for available credit capacity of the financial institutions, many of which are in the process of deleveraging their balance sheets. It remains uncertain what credit capacity we will be able to obtain upon renewal. In addition, it is likely that the cost of such credit facilities (spreads over LIBOR) will increase above current levels. The amount of credit capacity we are able to obtain and the ultimate cost of such credit could have a negative impact on our liquidity, cost of capital and financial results. In addition, to the extent that we decrease the amount of capacity under our corporate revolver when it is renewed, there is a risk that such liquidity levels may not be adequate in the future especially if commodity prices remain at or decline from current levels and our access to capital markets is restricted in the future. In that case, such liquidity levels may not be adequate to manage our business and we could be significantly adversely affected. Finally, the financial covenants set forth in any new facility may be more restrictive than our current facility and reduce our financial and operating flexibility.

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 proved 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 addition, currently our proved reserves serve as collateral for many of the derivative contracts that we enter into to hedge the commodity price for our production. A reduction in our proved reserves could require us to post additional collateral in the future for a portion of those derivative contracts.

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.

Certain of our debt and other financing obligations contain restrictive covenants, including debt to earnings before interest, income taxes, depreciation and amortization (EBITDA) and fixed charges to EBITDA covenants in our revolving credit agreement, and contain cross default provisions. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we might not be able to repay such debt and other financing obligations. Additionally, some of our credit agreements are collateralized by our equity interests in EPNG and TGP as well as certain natural gas and oil reserves. A breach of the covenants under these agreements could permit the lenders to exercise their rights to foreclose on these collateral interests.

We are subject to interest rate risks.

Although a substantial portion of our debt capital structure has fixed interest rates, changes in market conditions, including potential increases in the deficits of foreign, federal and state governments, could have a negative impact on interest rates that could cause our financing costs to increase. Since interest rates are at historically low levels, it is anticipated that they will increase in the future. Rising interest rates could also negatively impact the market value of our investment in EPB, as changes in interest rates may affect the yield requirements of investors in its units.

Our inability to satisfy all conditions precedent under the transaction with Global Infrastructure Partners (GIP) and the lenders associated with the Ruby pipeline project could require us to pay all amounts owed to GIP and the lenders under the associated equity and debt instruments.

GIP has invested approximately $700 million to acquire a 50 percent indirect interest in our Ruby pipeline project. Subject to certain extensions, to the extent that we are unable to complete the construction of the Ruby pipeline by near the end of 2011, then GIP has an option to require us to repurchase its equity interests. These repayment obligations are secured by various interests in Ruby Pipeline Holding Company, L.L.C. (Ruby), Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains) and certain of our common units held in EPB. Adverse economic conditions, as well as restrictions on our ability to access the capital markets could negatively impact our ability to meet such obligations, as well as permit GIP to foreclose on such security interests. In addition, GIP can elect to maintain its equity interest in Cheyenne Plains if we fail to complete the Ruby pipeline by near the end of 2011. We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us.

We depend on distributions from our subsidiaries and joint ventures to meet our needs.

We hold debt at a holding company level, a company with no significant assets other than our ownership interests in our operating subsidiaries. We are dependent on the earnings and cash flows, dividends, loans or other distributions from our subsidiaries and joint ventures to generate the funds necessary to meet these obligations. Applicable law and contractual restrictions (including restrictions in our subsidiaries credit facilities and in our joint venture or partnership agreements) may negatively impact our ability to obtain such distributions from our subsidiaries, including the rights of the creditors of our subsidiaries that would often be superior to our interests. A substantial portion of our investments in our interstate pipeline assets are held through subsidiaries or joint ventures. In this regard, our partnership interest in EPB and our 50% ownership interest in Citrus (the holding company for Florida Gas) generally generate substantial cash flow to us. Therefore, our cash flow is dependent upon the ability of EPB to make distributions to its partners (including the incentive distribution rights to us as the general partner) and the level of distributions by Citrus to us, net of any cash calls. A significant decline in EPB s or Citrus earnings and/or cash distributions would have a corresponding negative impact on us. For information on the risk factors inherent in the business of EPB, see Item 1A. Risk Factors in the EPB Annual Report and subsequent filings thereof.

Our ability to continue to sell interests in our interstate pipelines and LNG facilities to EPB could be negatively impacted by various factors that would restrict its use as a cost effective vehicle for us to raise capital.

An important source of capital to us in the past and potentially in the future is the sale of interests in our interstate pipelines and LNG facilities to our master limited partnership, EPB. As the general partner of EPB, we are entitled to incentive distribution rights (IDRs). We are currently entitled to receive the maximum level of IDRs. Our ability to sell additional interests to EPB on an accretive basis to the limited partner unitholders may be negatively impacted by such IDRs unless we elect to reduce the level of the IDRs as provided for in the partnership agreement. In addition, as the general partner of the partnership, we could also be subject to claims associated with conflicts of interest and breach of fiduciary duties. Although the partnership agreements expressly define and limit our obligations as the general partner, if any conflicts of interest or breach of fiduciary duties are found, then our ability to sell additional interests in our interstate pipeline assets to EPB could be negatively impacted and any liability resulting from such claims could be material. In either event, there is a risk that this source of capital to us may not be available to us or may become more restricted, thereby negatively impacting the deleveraging of our balance sheet and/or our future capital programs. The ability to sell additional interests in our interstate pipelines and LNG facilities to EPB is also subject to the ability of EPB to access the capital markets. If the access to such markets is unavailable or restricted or if the cost of capital increases, then this important source of capital to us could be negatively impacted in the future. Finally, our ability to sell interests in other pipeline subsidiaries may be restricted by covenants under existing debt agreements.

We may not be able to execute our long range plan and growth strategy as planned.

Our ability to execute our long range plan and our growth strategy is dependent on many factors outside of our control. As a result, our projected revenues, earnings, cash flows and the reductions in our debt levels over the plan cycle may be less than our plan has anticipated. The actual results derived from our businesses could deviate materially from planned outcomes. Our long range plan could also be impacted by material acquisitions, divestitures or restructurings of our businesses that we believe would be beneficial to our investors.

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

A description of our material legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 12, and is incorporated herein by reference.

EPA Compliance Order Bluebell Gas Plant. In February 2008, we received a Compliance Order from Region 8 of the EPA alleging violations of Clean Air Act regulations at the Bluebell Gas Plant and other facilities. The allegations concerned the compliance of those facilities with hazardous air pollutant regulations under the Clean Air Act. The Compliance Order did not specify what, if any, penalty may result. After meeting with the EPA in June 2008 and conducting testing requested by the EPA, we determined that only the Bluebell Gas Plant was subject to the regulations. Following that determination, we worked with the EPA and the Utah Department of Environmental Quality so that the Bluebell Gas Plant complied with these regulations. In the first quarter of 2010, the Bluebell Gas Plant was shut down, and we have informed the EPA and the Utah Department of Environmental Quality of this information. We have requested that the EPA close this Compliance Order and are awaiting response from the EPA.

ITEM 4. (REMOVED AND RESERVED)

Table of Contents

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol EP. As of February 22, 2011, we had 26,387 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
2010			
Fourth Quarter	$14.08	$12.00	$0.01
Third Quarter	12.93	10.60	0.01
Second Quarter	13.00	10.17	0.01
First Quarter	11.59	9.55	0.01
2009			
Fourth Quarter	$11.37	$ 8.94	$0.01
Third Quarter	10.85	8.00	0.05
Second Quarter	10.91	6.10	0.05
First Quarter	9.52	5.22	0.05

Stock Performance Graph. This graph reflects the comparative changes in the value of $100 invested since December 31, 2005 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 2010 included the following companies: Anadarko Petroleum Corp., CenterPoint Energy Inc., Dominion Resources, Inc., Enbridge, Inc., Energen Corp., EQT Corp., National Fuel Gas Co., Newfield Exploration Co., NiSource, Inc., Noble Corp., ONEOK, Inc., Pioneer Natural Resources Co., Questar Corp., Sempra Energy, Southern Union Co., Spectra Energy Corp., TransCanada Corp., and Williams Companies, Inc. Our peer group for 2009 included Apache Corp., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources Inc., XTO Energy Inc., and the companies listed above excluding Energen Corp.

COMPARISON OF ANNUAL CUMULATIVE TOTAL RETURNS

	12/05	12/06	12/07	12/08	12/09	12/10
El Paso Corporation	$100	$127.09	$144.81	$66.73	$ 85.49	$120.03
S&P 500 Stock Index	$100	$115.79	$122.16	$76.96	$ 97.33	$112.03
S&P 500 Oil & Gas Storage & Transportation Index	$100	$118.95	$135.88	$67.53	$ 94.37	$120.23
2010 Peer Group	$100	$117.51	$142.83	$86.59	$138.34	$171.03
2009 Peer Group	$100	$107.56	$138.49	$90.74	$140.64	$168.21

Note: 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 8, 2011, we declared a quarterly dividend of $0.01 per share of our common stock, payable on April 1, 2011, to shareholders of record as of March 4, 2011. Future dividends will depend on business conditions, earnings, our cash requirements and other relevant factors.

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

Table of Contents

ITEM 6: SELECTED FINANCIAL DATA

The following selected historical financial data as of December 31, 2008 to 2010 and for the years ended December 31, 2007 to 2010 is derived from the audited consolidated financial statements for El Paso and its subsidiaries. The selected financial data as of December 31, 2007 and 2006 and for the year ended December 31, 2006 is derived from unaudited consolidated financial statements adjusted to reflect the adoption in 2009 of new presentation and disclosure requirements for noncontrolling interests. The selected financial data is not necessarily indicative of results to be expected in future periods and 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,				
	2010	2009	2008	2007	2006
	(In millions, except per common share amounts)				
Operating Results Data:					
Operating revenues	$ 4,616	$ 4,631	$ 5,363	$ 4,648	$ 4,281
Net income (loss)	$ 924	$ (474)	$ (789)	$ 442	$ 532
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 721	$ (576)	$ (860)	$ 1,073	$ 438
Earnings (loss) per common share attributable to El Paso Corporation s common stockholders:					
Basic	$ 1.03	$ (0.83)	$ (1.24)	$ 0.57	$ 0.73
Diluted	$ 1.00	$ (0.83)	$ (1.24)	$ 0.57	$ 0.72
Cash dividends declared per common share	$ 0.04	$ 0.16	$ 0.18	$ 0.16	$ 0.16
Basic average common shares outstanding	698	696	696	696	678
Diluted average common shares outstanding	762	696	696	699	739
Financial Position Data:					
Total assets	$25,270	$22,505	$23,668	$24,579	$27,261
Long-term financing obligations, less current maturities	$13,517	$13,391	$12,818	$12,483	$13,329
Preferred stock of subsidiaries	$ 698	$ 145	$	$	$
Total equity	$ 6,064	$ 3,991	$ 4,596	$ 5,845	$ 4,217

Factors Affecting Trends. During 2010, we issued noncontrolling interests in our master limited partnership of approximately $1.3 billion and increased the preferred stock of our subsidiaries, Ruby and Cheyenne Plains. During 2009 and 2008, we recorded non-cash full cost ceiling test charges of $2.1 billion and $2.7 billion, principally as a result of declines in commodity prices. In 2007, we sold our ANR pipeline system and related assets and also completed the initial public offering of common units in EPB, our master limited partnership.

Table of Contents

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 2010 performance and an outlook for 2011;

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 2011, an overview of cash flow activity during 2010, and additional factors that could impact our liquidity;

Off Balance Sheet Arrangements and Contractual Obligations includes a discussion of our (i) off balance sheet arrangements, including guarantees and letters of credit and (ii) other contractual obligations; 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

We 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, which provide a stable base of earnings and cash flow and have a 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. We also have an emerging midstream business.

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, the costs to explore, develop, and produce natural gas and oil, and the volumes we are able to produce, among other factors. Our long-term profitability in each of our operating segments will be primarily influenced by the following factors:

Pipelines

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

Table of Contents

Exploration and Production

- Growing our natural gas and oil proved reserve base and production volumes through successful low-risk drilling programs;
- 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 be affected by the impacts of volatility in the financial and commodity markets, our debt level and related interest costs, the successful resolution of our historical contingencies and other legacy activities.

Summary of 2010 Performance

During 2010, we generated significant earnings in both our pipeline and exploration and production businesses and continued to focus on delivering on our remaining backlog of pipeline expansion projects, and achieving operational success in our exploration and production business. During 2010, in our pipeline business, we placed approximately $1 billion of pipeline expansion projects into service, all on time and in total approximately $100 million under budget. We also continued to advance our Ruby project, our largest pipeline expansion project, which we currently expect to go into service in July 2011 at an updated total cost of approximately $3.55 billion. In our exploration and production business, we have continued executing on our strategy, with increased production volumes, lower per unit cash operating costs, and an expanded 2011 and 2012 hedging program designed to support our balance sheet and cash flows. We commenced shifting our capital program in 2010 to provide us more exposure to oil opportunities, particularly in the Altamont, Eagle Ford and Wolfcamp areas. We believe the stability of our pipeline earnings coupled with the hedging program in our exploration and production business will continue to protect our earnings base and cash flows from operations.

The following table provides highlights in our core businesses and financing activities:

Area of Operations	Significant Highlights
Pipelines	Completed a $1.5 billion project financing facility on our Ruby pipeline expansion project, received final approval from the FERC, and began construction of the project
	Progressed on our remaining backlog of expansion projects completing five expansion projects on time and on or under budget, including Phase A of both the SLNG Elba Expansion III and the Elba Express Pipeline expansion, the CIG Raton 2010 expansion, the WIC System expansion and Phase I of the SNG South System III project
	Received $2.3 billion in cash in conjunction with contributing ownership interests in SLNG, Elba Express and SNG to our MLP funded through the issuance of MLP debt and unit issuances
	Sold interests in certain Mexican pipeline and compression assets for approximately $0.3 billion
	Filed new rate cases with the FERC for our EPNG and TGP systems
Exploration and Production	Achieved an overall domestic drilling success rate of 98 percent
	Focused our domestic capital program on our core programs including the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont fractured tight sands in Utah. In late 2010, we also acquired 123,000 net acres in the Wolfcamp Shale in the Permian Basin in Texas.

Managed commodity price risk through derivative contracts on 2010, 2011 and 2012 natural gas production

Increased oil and liquids based revenues in 2010 to 23 percent of our total revenues, an 8 percent increase from 2009

Table of Contents

We also entered into a joint venture in our emerging midstream business and sold a 50 percent interest in our Altamont gathering and processing assets for $125 million in cash. Under the venture, we and our partner expect to each invest up to approximately $500 million in future midstream projects. While our current level of earnings from our midstream business is not significant, there are a number of projects we are evaluating, and believe that the movement to more unconventional supply basins will present future opportunities in this business.

Outlook for 2011

In 2011, we expect that our pipeline operations will continue to provide a strong base of earnings and operating cash flow. Approximately 80 percent of our pipeline revenues are collected in the form of demand or reservation charges, which are not dependent upon commodity prices or throughput levels. This, coupled with the diversity of our pipeline systems, helps mitigate against the risk of changes in throughput and ongoing shifts in supply and demand. During 2010, we experienced lower demand and firm transportation commitments on our EPNG system and long haul transportation being replaced by short haul transportation on our TGP system. Additionally as a result of the shift in flow patterns of our TGP system, we experienced lower realized prices and volumes of gas not used in operations. Our pipeline results are also impacted by rate cases. Currently, two of our pipelines have outstanding rate cases pending before the FERC and certain of our other pipelines have projected upcoming rate actions with anticipated effective dates from 2011 through 2014. Our 2011 pipeline capital expenditure program is expected to be approximately $1.7 billion, including $1.3 billion on our remaining backlog of growth projects. We currently plan to place five more projects in service by the end of 2011.

In our exploration and production business, we also expect to generate significant earnings and operating cash flow . Our planned average daily production for 2011 is expected to range between 790 MMcfe/d and 840 MMcfe/d, including approximately 60 MMcfe/d from our ownership interest in the production of Four Star. We expect the trend of low natural gas prices to continue and have expanded our financial derivative contracts in place for 2011 providing $5.95 average floors on approximately 75 percent of our estimated domestic natural gas production and $86.00-$92.00 per barrel collars on approximately 85 percent of our estimated oil production. We have also expanded our 2012 natural gas and oil hedge program. Our oil and natural gas production hedge programs will help protect our cash flows in these years. In addition, we have focused on execution and cost management to ensure favorable economics of our programs in the current low gas price environment.

In our exploration and production business, we expect to spend approximately $1.3 billion in capital expenditures during 2011 with 90-95 percent focused domestically in our Haynesville, Altamont, Eagle Ford, and Wolfcamp areas. This capital focus provides us greater exposure to both oil and natural gas liquids opportunities. We are considering securing a joint venture partner for our Eagle Ford oil acreage to accelerate development of this core area and deliver higher returns on invested capital.

In our emerging midstream business, we will continue to seek out opportunities that focus on synergies with our pipeline and/or exploration and production businesses, funding these projects in a manner that is consistent with our long-term goal of improving our balance sheet, including the evaluation of partnership opportunities on our projects.

As of December 31, 2010, we had approximately $2.4 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby). We expect our available liquidity and operating cash flows in 2011 to be sufficient to fund our estimated $3.2 billion 2011 capital program. In 2011 we also have debt maturities of approximately $500 million which we will pay off as they mature. Additionally, before the end of 2012 we will be required to renew our three primary revolving credit facilities. As a result of our 2010 actions, our current available liquidity, hedging program in place on our natural gas and oil production, and planned future actions (including continuing with our MLP drop down strategy as market conditions permit), we believe we are well positioned in 2011 to meet our obligations as well as continue with our efforts to strengthen our balance sheet. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements as well as address any changes in the financial and commodity markets and our businesses. For a further discussion, see *Liquidity and Capital Resources*.

Table of Contents

Results of Operations

Overview

We have two core operating business segments, Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages legacy trading contracts. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Prior to 2010, we also had a Power segment which has been combined into our corporate and other activities for all periods presented. Our corporate and other activities include our general and administrative functions, and other miscellaneous businesses, including our newly formed midstream business.

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 our operating performance using the same performance measure analyzed internally by our management and so that our investors may evaluate our operating results without regard to our financing methods or capital structure. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense, (ii) income taxes and (iii) net income attributable to noncontrolling interests. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income (loss), income (loss) before income taxes 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:

	2010	2009	2008
		(In millions)	
Pipelines	$ 1,572	$ 1,416	$ 1,273
Exploration and Production	727	(1,349)	(1,448)
Marketing	(50)	20	(104)
Corporate and other	(74)	(17)	125
EBIT	2,175	70	(154)
Interest and debt expense	(1,031)	(1,008)	(914)
Income tax benefit (expense)	(386)	399	245
Net income (loss) attributable to El Paso Corporation	758	(539)	(823)
Net income attributable to noncontrolling interests	166	65	34
Net income (loss)	$ 924	$ (474)	$ (789)

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.

Table of Contents

Pipelines Segment

Overview

Our Pipelines segment operates 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, and LNG terminalling related services consist of two types:

Type	Description	Percent of 2010 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.	81
Usage and Other	Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges and provide fuel in-kind 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.	19

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, changes in gas flows, regulatory actions, competition, weather and declines in the creditworthiness of our customers. We also experience earnings volatility on one of our pipelines when the amount of natural gas used in our 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 the process of renewing expiring contracts to limit the risk of significant impacts on our revenues. Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and the 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. Although we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariffs, we frequently enter into firm transportation contracts at amounts that are less than these maximum rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems. Our existing contracts mature at various times and in varying amounts of throughput capacity. The weighted average remaining contract term for our active contracts is approximately six years as of December 31, 2010.

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, 2010, including those with terms beginning in 2010 or later:

	Contracted Capacity BBtu/d	Percent of Total	Reservation Revenue (In millions)	Percent of Total Reservation Revenue
2011	3,302	12	$ 173	8
2012	4,333	15	271	12
2013	5,733	20	466	21
2014	1,355	5	82	4
2015	3,337	12	268	12
2016 and beyond	10,018	36	922	43
Total	28,078	100	$ 2,182	100

Summary of Operational and Financial Performance

Our EBIT increased approximately 11 percent when comparing both the year ended December 31, 2010 with 2009 and 2009 compared to 2008. In both 2010 and 2009 our EBIT benefited from expansion projects placed into service and an increase in the allowance for funds used during construction related to pipeline expansion projects not yet in service, such as our Ruby project. However, during both periods, net income attributable to noncontrolling interests also increased as a result of contributing assets to EPB coupled with a decline in revenues from the EPNG and TGP systems.

During 2011, we plan to spend $1.7 billion in capital on our pipeline business, including $1.3 billion on our remaining backlog of expansion projects. Our most significant projects are listed below, grouped by anticipated in-service dates.

Project	Anticipated In-Service Dates	Total Estimated Project Costs (In billions)	Cumulative Project Spend as of December 31, 2010	FERC Approved
2011:				
FGT Phase VIII Expansion (50%)[(1)(2)]	April 2011	$ 1.2	$ 1.0	Yes
Ruby Pipeline[(1)(3)]	July 2011	3.55	2.8	Yes
South System III and Southeast Supply Header Phase II[(1)(4)]	June 2011/June 2012	0.4	0.2	Yes
Gulf LNG Clean Energy (50%)[(2)(5)]	October 2011	0.8	0.7	Yes
TGP 300 Line Project	November 2011	0.7	0.2	Yes
2012 and Beyond:				
TGP Northeast Upgrade Project	November 2013	0.4		No

(1) These projects have substantial contractual commitments with customers but are not fully contracted.

(2) Amounts represent our proportional share of the estimated costs for these unconsolidated affiliates. Our estimated equity contribution is included in our expected 2011 capital plan.

(3) Amount includes 100 percent of our Ruby pipeline project expenditures. As of December 31, 2010, we have received approximately $0.7 billion in funding from our equity partner on this project.

(4) The South System III expansion project consists of three phases. In January 2011, Phase I of the project was placed in service. Phases II and III are expected to be placed in service in June 2011 and June 2012, respectively. Phase II of the Southeast Supply Header project is expected to be placed in service in June 2011.

(5) Amount includes approximately $295 million that we paid to acquire a 50 percent interest in this project.

Table of Contents

Listed below is additional information related to certain of our significant backlog projects:

Ruby Pipeline Project. The Ruby pipeline project consists of approximately 680 miles of 42 pipeline and multiple compressor stations with total horsepower of approximately 157,000. We have 1.1 Bcf/d contractually committed on a firm basis from customers for 10 to 15 years out of a total design capacity of 1.5 Bcf/d. In 2010, we received a BLM right-of-way grant for the project, final approval from the FERC and began construction of the pipeline. Several groups have filed appeals with the U.S. Court of Appeals of certain approvals and actions of the FERC, BLM and the U.S. Fish and Wildlife Service related to the project. Although we are currently able to continue construction of the pipeline pending the federal court of appeals review of the petitions, we are currently unable to predict what action, if any, the court will take in response to these appeals or any subsequent filings that may be made by one or more of these groups.

Construction of the Ruby pipeline project continues to advance, with approximately 85 percent of the pipe welded. In order to avoid interference with the sage grouse during its mating season in certain areas of a 40-mile portion of the route in Nevada, construction will be suspended in this area from March 1 to May 15 of 2011. We have updated our cost estimate and now expect the project to be completed at a cost of approximately $3.55 billion and be placed in service in July 2011. Although we have made substantial progress in constructing the pipeline, our ability to complete the project by this date and within these estimated costs will continue to depend on factors outside of our control, including any delays in obtaining additional regulatory clearances, any adverse court determinations with regard to existing regulatory clearances, adverse weather conditions and our ability to complete construction activities during certain work periods provided for in our regulatory authorizations.

TGP 300 Line Project. All of the firm transportation capacity resulting from this project in the northeast U.S. market area is fully subscribed with one shipper based on an executed precedent agreement. During 2010, the FERC issued a favorable environmental assessment and TGP received certificate authorization from the FERC to construct the pipeline and compression facilities. In June 2010, we commenced construction on our compression facilities related to this project, with construction of the remaining facilities to occur in 2011.

TGP Northeast Upgrade Project. In 2010, TGP entered into precedent agreements with two shippers to provide 636 MMcf/d of additional firm transportation service from receipt points in the Marcellus Shale basin to an interconnect in New Jersey. All of the firm transportation capacity is fully subscribed with these two shippers. In order to accommodate the additional service, we will pursue this project which includes approximately 40 miles of 30 inch pipeline looping and approximately 22,310 horsepower of additional compression.

Successful execution on our committed pipeline backlog will continue to require effective project management. We attempt to mitigate the market risk associated with our expansion projects through subscribing a substantial portion of the capacity under long-term contracts with investment-grade customers and purchasing or committing to purchase steel at fixed prices as well as contracting a significant portion of the construction costs.

Table of Contents

Operating Results

	2010	2009	2008
	(In millions, except volumes)		
Operating revenues	$ 2,820	$ 2,767	$ 2,684
Operating expenses	(1,517)	(1,486)	(1,532)
Operating income	1,303	1,281	1,152
Other income, net	435	200	156
EBIT before noncontrolling interests	1,738	1,481	1,308
Net income attributable to noncontrolling interests	(166)	(65)	(35)
EBIT	$ 1,572	$ 1,416	$ 1,273
Throughput volumes (BBtu/d)[(1)]			
TGP	5,081	4,614	4,864
EPNG and MPC	3,395	3,982	4,422
CIG, WIC and CPG	5,100	5,550	5,376
SNG	2,505	2,322	2,339
Other	16	50	50
Equity investments[(2)]	1,372	1,820	1,763
Total throughput	17,469	18,338	18,814

(1) Volumes exclude intrasegment activities.

(2) Represents our proportional share of unconsolidated affiliates.

Below is a discussion of factors impacting EBIT in 2010 compared with 2009 and 2009 as compared with 2008. We have also provided an outlook on events that could impact EBIT in future periods.

	2010 to 2009 Variance				2009 to 2008 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 163	$ (29)	$ 149	$ 283	$ 103	$ (25)	$ 49	$ 127
Reservation and usage revenues	(26)			(26)	23			23
Gas not used in operations and revaluations	(77)	8		(69)	2	30		32
Bankruptcy proceeds					(48)	(1)		(49)
Operating and general and administrative expense		23		23		4		4
Asset write downs		(33)		(33)		42		42
Sale of Mexican assets			80	80				
Other[1]	(7)		6	(1)	3	(4)	(5)	(6)
Total impact on EBIT before adjustment for noncontrolling interests	53	(31)	235	257	83	46	44	173
Net income attributable to noncontrolling interests			(101)	(101)			(30)	(30)
Total impact on EBIT	$ 53	$ (31)	$ 134	$ 156	$ 83	$ 46	$ 14	$ 143

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

Expansions. During 2010 and 2009, we benefited from increased reservation revenues due to expansion projects placed in service. These projects included the Carthage expansion, the Totem Gas Storage facility, the Concord Lateral expansion, the WIC System expansion, Phase A of both the SLNG Elba Expansion III and Elba Express Pipeline expansion, and the CIG Raton 2010 expansion.

We capitalize a carrying cost (AFUDC) on equity funds related to our construction of long-lived assets. During the years ended December 31, 2010 and 2009, we benefited from an increase in other income of approximately $149 million and $49 million associated with the equity portion of AFUDC on our expansion projects. This increase was primarily due to our Ruby pipeline project in 2010 and our SLNG Elba Expansion III and Elba Express Pipeline expansion projects in 2009. Subsequent to placing expansion projects in service, our level of earnings will depend on the level of contracted customer capacity and our ability to market unsubscribed firm capacity. Currently, approximately 1.1 Bcf/d on our Ruby pipeline project is subscribed and we do not expect additional firm capacity subscriptions in the near term.

Until placed in service, our Ruby project will be consolidated in our financial results. We currently fund and reflect 100 percent of the capital cost of this project, including cost overruns, in our results which reflect higher AFUDC capitalized due to project delays. Shortly after completion of this project, subject to meeting certain conditions, we anticipate reflecting Ruby in our financial statements as an equity investment in which we own 50 percent. Once deconsolidated, we will be required to evaluate our investment in Ruby for impairment. Based on increased costs and delays in project completion which impact the net book value of our investment, depending on the fair value at the time of evaluation, we may be required to write-down a portion of our investment in Ruby. Additionally, we will reflect equity earnings from Ruby in EBIT after the impact of interest expense and taxes and preferred interests. As such, our EBIT contribution from Ruby will decline once the pipeline is placed in service.

61

Reservation and Usage Revenues. Our reservation and usage revenues variance, when comparing the three year period ended December 31, 2010, primarily relates to changes on our EPNG, TGP and SNG pipeline systems as further discussed in the table below (in millions) and discussion that follows.

Pipeline System	2010 to 2009	2009 to 2008
EPNG	$ (76)	$ 11
TGP	(12)	(12)
SNG[(1)]	50	24
Other[(2)]	12	
Total	$ (26)	$ 23

(1) Increases primarily due to higher tariff rates effective September 1, 2009 due to SNG s rate case settlement.

(2) Consists of individually insignificant items on our other pipeline systems.

During 2009, EPNG experienced increased contracted capacity to its primary delivery points in California which resulted in higher reservation revenues of approximately $15 million when compared to 2008. However, EPNG s throughput volumes decreased in 2009 and 2010 due to lower natural gas and electric generation demand resulting from weak macroeconomic conditions in the southwestern U.S., increased competition in its California and Arizona market areas, including increased activity from an LNG facility and reduced basis differentials which unfavorably impacted our EBIT by $4 million and $76 million when compared with prior periods.

On our TGP system, when comparing 2009 to 2008, our overall EBIT was unfavorably impacted by a $20 million decrease in activity under various interruptible services and lower demand from increased competition in the southeast area and milder weather partially offset by executed transportation capacity contracts with shippers primarily from the Marcellus shale basin in the northeast market area which increased our reservation revenues by approximately $8 million when compared with 2008.

Throughput volumes on our TGP system increased during 2010 compared to 2009. However, our reservation and usage revenues were lower by approximately $10 million primarily because long-haul transports on our TGP system have decreased due to a shift in receipts from the Gulf Coast region to the Rockies Express Pipeline interconnect in Ohio and the Marcellus shale basin, which is short-haul transportation and subject to lower rates. We believe our Marcellus expansion projects (TGP 300 Line Project, TGP Northeast Upgrade Project and TGP Northeast Supply Diversification Project) will expand our presence from Marcellus to the New York and New England markets.

Throughput can affect our level of revenues from commodity charges, and items such as changes in gas flows on our TGP and EPNG systems, or be an indication of the risks we may face when seeking to recontract or renew any of our existing firm transportation contracts. Continuing negative economic impacts on demand, as well as adverse shifting of sources of supply, could negatively impact basis differentials and our ability to renew firm transportation contracts that are expiring on our systems or our ability to renew such contracts at current rates. Although this risk exists for all of our pipelines, it is the most significant on our EPNG system where we may be required to further discount certain transportation rates in order to renew certain firm transportation contracts should these conditions continue.

If we determine there is significant change in our revenues, costs or billing determinants on any of our pipeline systems, we have the option to file rates cases with the FERC on certain of our pipelines to provide an opportunity to recover our prudently incurred costs. During 2010, EPNG and TGP filed rate cases with the FERC. Although these rate cases are intended to address significant factors leading to the loss in revenues or increased costs, they will not eliminate all ongoing business risks including competition and shifts in throughput.

Gas Not Used in Operations and Revaluations. For the year ended December 31, 2010 when compared with 2009, our EBIT was unfavorably impacted by $69 million due to lower realized prices and lower volumes of gas not used in operations as a result of the shift in flow patterns primarily on our TGP system, partially offset by $15 million of lower electric compression usage. Higher realized prices on operational sales and lower imbalance revaluations contributed favorably to our EBIT by approximately $16 million in 2009 compared to 2008. In addition, lower electric compression usage increased our EBIT by $13 million for the year ended December 31, 2009 when compared to 2008. Our future earnings may be impacted positively or negatively depending on changes in throughput, as well as fluctuations in natural gas prices. We continue to explore options to minimize the price volatility associated with these operational pipeline activities. As a result of the TGP rate case filed with the FERC which proposes an increase in base tariff rates effective June 1, 2011, the percentage of our revenues derived from reservation charges may increase and therefore may reduce the impacts to our EBIT due to excess fuel recoveries.

Bankruptcy Proceeds. During 2008, our revenue increased by $39 million related to Calpine Corporation s (Calpine s) rejection of its transportation contracts with us primarily associated with distributions received under Calpine s approved plan of reorganization. During 2008, we recorded income of approximately $10 million, net of amounts potentially owed to certain customers, related to amounts recovered from the Enron bankruptcy settlement.

Operating and General and Administrative Expenses. For the year ended December 31, 2010, our operating and general and administrative expenses were lower than in 2009 primarily due to severance costs of approximately $14 million recorded in 2009. Additionally, when comparing the year ended December 31, 2009 to 2008, our operating and general and administrative expenses were favorably impacted by $18 million of decreased field repair and maintenance expense on several of our pipeline systems.

Asset Write Downs. During 2010, we incurred a $21 million non-cash asset write down based on a FERC order related to the sale of the Natural Buttes compressor station and gas processing plant in 2009. During 2009, we recorded a gain of $8 million related to the sale of these assets. We recorded impairments of approximately $10 million and $4 million in 2010 and 2009 primarily related to our decision not to continue with a storage project due to market conditions. 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 were no longer developing due to declining real estate values.

TGP entered into an agreement with an effective date of October 2010 to sell certain of their offshore pipeline assets and related facilities. TGP has filed an abandonment application with the FERC related to the sale. The sale is contingent upon receiving FERC approval of the abandonment application including the ability to recover in future rates the difference between the regulatory net book value and purchase price as well as the designation of certain facilities as non-jurisdictional. If approved, TGP expects to complete the sale of these assets by mid-2012 and may incur a loss on the sale for financial accounting purposes. However, the outcome of the FERC s approval of the application is currently undeterminable. As such, the assets are not considered as held for sale.

Sale of Mexican Assets. During 2010, we recorded a gain of approximately $80 million on the sale of our interests in certain Mexican pipeline and compression assets.

Net Income Attributable to Noncontrolling Interests. Our net income attributable to noncontrolling interests increased during 2010 and 2009 due to the issuance of additional public common units and the contribution of additional assets into the MLP. In 2010, our MLP has issued 46.5 million additional public common units. Also, during 2010, we contributed an additional 35 percent interest in SNG and a 100 percent interest in SLNG and Elba Express to the MLP. As of December 31, 2010, our ownership interest in the MLP is 51 percent, including our two percent general partner interest.

Net income attributable to noncontrolling interests also includes preferred returns on GIP s interests in Cheyenne Plains and Ruby. For the year ended December 31, 2010, we recorded $49 million associated with GIP s preferred interests in Cheyenne Plains and Ruby. For further discussion of preferred stock of subsidiaries, see Item 8, Financial Statements and Supplementary Data, Note 14.

Below is a discussion of items that could impact our EBIT in future periods.

Our pipeline systems periodically file for changes in their rates, which are subject to the approval by 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 from 2011 through 2014 as discussed below.

SNG Rate Case. In January 2010, the FERC approved SNG s settlement in which SNG (i) increased its base tariff rates, effective September 1, 2009, (ii) implemented a volume tracker for gas used in operations, (iii) agreed to file its next general rate case to be effective after August 31, 2012 but no later than September 1, 2013, and (iv) extended the vast majority of SNG s firm transportation contracts until August 31, 2013.

EPNG Rate Case. In April 2010, the FERC approved an uncontested partial offer of settlement which increased EPNG s base tariff rates effective January 1, 2009. As part of the settlement, EPNG made refunds to its customers in 2010. The settlement resolved all but four issues in the proceeding. In January 2011, the Presiding Administrative Law Judge issued a decision that for the most part found against EPNG on the four issues. EPNG will appeal those decisions to the FERC and may also seek review of any of the FERC s decisions to the U.S. Court of Appeals. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates as permitted under the settlement of the previous rate case. These new base tariff rates would increase revenue by approximately $107 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates, including a proposed change in its rate structure which is expected to increase the percentage of reservation revenues on TGP relative to revenues derived from excess fuel recoveries and throughput on this system. These new base tariff rates would increase revenue by approximately $203 million annually over previously effective tariff rates. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

CIG Rate Case. Under the terms of its 2006 rate case settlement, CIG must file a new general rate case to be effective no later than October 1, 2011. In late January 2011, CIG filed with FERC an amendment of the 2006 settlement, which is unopposed by all of CIG s shippers, to request a modification of the settlement to allow the effective date of the required new rate case to be moved to December 1, 2011. The purpose of the delay in filing date is to allow CIG and its shippers the opportunity to reach a settlement of the rate proceeding before it is formally filed with the FERC. At this time, the outcome of the pre-filing settlement negotiations and the outcome of the upcoming general rate case, in the event pre-filing settlement cannot be reached, is uncertain.

Table of Contents

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. 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.

In 2010, approximately 93 percent of our capital was spent on domestic projects where we continued to focus on more unconventional resource plays including the Haynesville Shale in northwest Louisiana and east Texas, the Eagle Ford Shale in south Texas and the Altamont fractured tight sands in Utah. We also entered into the emerging Wolfcamp Shale in the Permian Basin through the lease of acreage in that area. With the current state of commodity prices and forecasts that project natural gas prices to remain low, our near term strategy has been to shift our focus toward the oilier and more liquids rich areas of our assets. In 2011, our capital will be primarily focused domestically, and will target our Haynesville, Altamont, Eagle Ford, and Wolfcamp areas. For more information on our estimated 2011 capital program, see *Outlook for 2011* below.

Internationally, our portfolio consists of producing fields along with several exploration and development projects in offshore Brazil and exploration projects in Egypt. Our 2010 international capital, primarily in Brazil, constituted approximately 7 percent of our total capital program. Success of our international programs in Brazil and Egypt will require effective project management, strong partner relations and obtaining approvals from regulatory agencies. Although there has been no material impact on our operations to date, it is uncertain what effect, if any, the political unrest associated with the changes in the government in Egypt will have on our short term or long term plans in the country.

We evaluate acquisition and growth opportunities that are focused on our core competencies and areas of competitive advantage. Strategic acquisitions, like our leasehold acquisitions in the Wolfcamp Shale in the Permian Basin, the Haynesville Shale and Eagle Ford Shale during 2010, and natural gas and oil properties in Altamont in Utah in 2009, can provide us greater opportunities to achieve our long term goals by leveraging existing expertise in key operating areas, can balance our exposure to regions, basins and commodities, can help us to achieve risk-adjusted returns competitive with those available within our existing inventory, and can increase our reserves by supplementing our current drilling inventory.

Our profitability and performance is impacted by our ability to execute upon our strategy, changes in commodity prices and industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating, and capital costs. Additionally we may be impacted by the effect of hurricanes and other weather events, or the effects of domestic or international regulatory or other actions in response to events outside of our control (e.g. oil spills). To the extent possible, we attempt to mitigate certain of these risks through actions, such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

Table of Contents

Significant Operational Factors Affecting the Year Ended December 31, 2010

Production. Our average daily production for the year was 782 MMcfe/d, including 62 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our 2010 production by division (MMcfe/d):

	2010	**2009**	**2008**
United States			
Central	328	257	238
Western	160	154	154
Gulf Coast	199	268	339
International			
Brazil	33	12	11
Total consolidated	720	691	742
Four Star	62	72	74
Total combined	782	763	816

Central division Our 2010 Central division production volumes continued to increase as a result of our successful Arklatex drilling programs including the Haynesville Shale. In the Haynesville Shale, we drilled 78 wells during the year and had average net production of approximately 143 MMcfe/d. At December 31, 2010, we had 58 operated wells producing at a rate of approximately 210 MMcfe/d.

Western division Our 2010 Western division production volumes increased primarily due to the successful drilling programs in Altamont offset by natural declines in the Rockies.

Gulf Coast division Our 2010 Gulf Coast division production volumes decreased primarily due to natural declines and lower levels of drilling activity. In this division, our 2010 focus was on increasing our Eagle Ford Shale acreage, where as of December 31, 2010, we hold approximately 170,000 net acres with approximately 105,000 net acres located in the liquids-rich area, and have successfully drilled 21 wells. We also acquired an additional 123,000 acres in the Wolfcamp Shale area, bringing our total leasehold amount to approximately 138,000 acres.

Brazil In Brazil, our 2010 production increased due to production from our Camarupim Field, where we began production in the fourth quarter of 2009.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil. Cash operating costs is a non-GAAP measure calculated on a per Mcfe basis and includes total operating expenses less depreciation, depletion and amortization expense, ceiling test and other impairment charges, transportation costs and cost of products. Cash operating costs per unit is a valuable measure of operating performance and efficiency for the exploration and production segment.

During the year ended December 31, 2010, cash operating costs per unit decreased to $1.78/Mcfe as compared to $1.82/Mcfe in 2009. The decrease in 2010 is primarily due to lower lease operating expenses and lower general and administrative expenses.

Table of Contents

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) (2) / Actual production for the corresponding period
Reserve replacement costs/Mcfe	Total oil and gas capital costs(3) / Sum of reserve additions (1) (2)

(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 present 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) The proved reserves used in the calculation of reserve replacement ratio and reserve replacement costs in 2010 and 2009 were determined based on the SEC s final rule on Modernization of Oil and Gas Reporting (Final Rule) effective December 31, 2009. The Final Rule, among other things, revised the definitions of proved reserves and required us to use the first day 12-month average price in determining estimated proved reserves.

(3) 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 developing 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, 2010, proved developed reserves represent approximately 60 percent of our total consolidated 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.

Table of Contents

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		
	2010	2009	2008	2010	2009	2008
		($/Mcfe)			($/Mcfe)	
Reserve Replacement Costs [1]						
Domestic						
Including acquisitions	$1.29	$1.84	$ 6.68	$1.56	$1.57	$2.87
Excluding acquisitions	1.29	1.91	7.01	1.58	1.59	2.87
Worldwide						
Including acquisitions	$1.40	$2.04	$36.00	$1.72	$1.76	$3.25
Excluding acquisitions	1.41	2.13	56.05	1.75	1.81	3.26
Reserve Replacement Ratios						
Domestic						
Including acquisitions	370%	188%	84%	306%	220%	195%
Excluding acquisitions	353%	162%	77%	289%	195%	188%
Worldwide						
Including acquisitions	347%	212%	17%	284%	245%	192%
Excluding acquisitions	331%	187%	11%	268%	220%	186%

(1) Only proved property acquisition costs are excluded from these calculations. Leasehold or unproved acquisitions costs are included in all calculations.

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, 2010.

	Including Price Revisions	Excluding Price Revisions
	Three Years Ending December 31, 2010 ($/Mcfe)	
Reserve Replacement Costs		
Domestic		
Including acquisitions	$ 2.19	$ 1.94
Excluding acquisitions	2.25	1.96
Worldwide		
Including acquisitions	$ 2.73	$ 2.16
Excluding acquisitions	2.84	2.20

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

	2010	2009	2008

		(In millions)	
Total oil and gas capital costs, excluding proved property acquisitions	$ 1,231	$ 1,004	$ 1,648
Proved property acquisitions	51	87	51
Total oil and gas capital costs, including acquisitions[1]	$ 1,282	$ 1,091	$ 1,699

[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 2011

For 2011, we expect the following on a worldwide basis:

Capital expenditures, excluding acquisitions, of approximately $1.3 billion. Of this total, we expect to spend approximately $1.2 billion on our domestic program (approximately half of which is expected to be allocated to oil and liquids programs) and approximately $0.1 billion in Brazil and Egypt. We will retain flexibility in allocating capital in response to market conditions such as changes in the price of natural gas and oil and our results in our core oil programs.

Average daily production volumes for the year of approximately 790 MMcfe/d to 840 MMcfe/d, which includes approximately 60 MMcfe/d from Four Star.

Average cash operating costs between $1.70/Mcfe and $1.90/Mcfe for the year; and

Depreciation, depletion and amortization rate between $1.90/Mcfe and $2.10/Mcfe.

Price Risk Management Activities

We enter into derivative contracts on our natural gas and oil production primarily to stabilize cash flows, and reduce the risk and financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge the entirety of our price risks, this strategy only partially reduces our commodity price exposure. Our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

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, 2010.

	2011		**2012**		**2013**	
	Volumes(1)	**Average Price**(1)	**Volumes**(1)	**Average Price**(1)	**Volumes**(1)	**Average Price**(1)
Natural Gas						
Fixed Price Swaps	160	$ 5.94	105	$ 6.01		$
Ceilings	18	$ 7.29		$		$
Floors	18	$ 6.00		$		$
Basis Swaps (2)						
Texas Gulf Coast	33	$ (0.13)		$		$
Mid-Continent	22	$ (0.25)		$		$
Oil						
Fixed Price Swaps	2,008	$87.54		$		$
Ceilings		$	1,464	$95.00	2,920	$96.88
Three Way Collars Ceiling	3,650	$94.27		$		$
Three Way Collars Floors (3)	3,650	$85.14		$		$

(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.

(3) Our three way collars-floors effectively lock-in a cash settlement of $20.14 above market prices on 3.7 MMBbls.

During the first two months of 2011, we entered into 641 MBbls of fixed price swaps on our anticipated 2012 oil production at an average price of $100.13 per barrel. We also entered into additional three-way collars on 4.3 MMBbls of our anticipated 2012 oil production. For these volumes, the transactions effectively provide an average ceiling price of $108.69 per barrel and an average floor price of $90.00 per barrel unless oil prices drop below $65.00 per barrel. If oil prices drop below $65.00 per barrel, the transactions effectively lock-in a cash settlement of the market price plus $25.00 per barrel.

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:

	2010	2009	2008
		(In millions)	
Physical sales:			
Natural gas	$ 974	$ 830	$ 1,960
Oil, condensate and NGL	406	267	541
Total physical sales	1,380	1,097	2,501
Realized and unrealized gains on financial derivatives[1]	390	687	196
Other revenues	19	44	65
Total operating revenues	1,789	1,828	2,762
Operating Expenses:			
Cost of products	15	31	38
Transportation costs	73	66	79
Production costs	264	252	363
Depreciation, depletion and amortization	477	440	799
General and administrative expenses	190	195	160
Ceiling test charges	25	2,123	2,669
Impairment of inventory and other assets		25	
Other	14	13	12
Total operating expenses	1,058	3,145	4,120
Operating income (loss)	731	(1,317)	(1,358)
Other income (expense)[2]	(4)	(32)	(90)
EBIT	$ 727	$ (1,349)	$ (1,448)

(1) Includes $12 million, $406 million and $(88) million for the years ended December 31, 2010, 2009 and 2008, reclassified from accumulated other comprehensive income associated with accounting hedges.

(2) Other income includes equity earnings from Four Star, our unconsolidated affiliate, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets. In 2008, other income also includes a $125 million impairment charge related to our equity interest in Four Star.

	2010	2009	2008
Volumes:			
Natural gas			
Consolidated volumes (MMcf)	225,611	218,544	232,703
Unconsolidated affiliate volumes (MMcf)	17,165	19,557	20,576
Oil, condensate and NGL			
Consolidated volumes (MBbls)	6,170	5,648	6,495
Unconsolidated affiliate volumes (MBbls)	937	1,097	1,054
Equivalent volumes			
Consolidated MMcfe	262,631	252,432	271,673
Unconsolidated affiliate MMcfe	22,787	26,139	26,899
Total combined MMcfe	285,418	278,571	298,572
Consolidated MMcfe/d	720	691	742
Unconsolidated affiliate MMcfe/d	62	72	74
Total Combined MMcfe/d	782	763	816
Consolidated prices and costs per unit:			
Natural gas			
Average realized price on physical sales ($/Mcf)	$ 4.32	$ 3.80	$ 8.43
Average realized prices, including financial derivative settlements ($/Mcf)(1)	$ 5.67	$ 7.62	$ 8.18
Average transportation costs ($/Mcf)	$ 0.30	$ 0.28	$ 0.31
Oil, condensate and NGL			
Average realized price on physical sales ($/Bbl)	$ 65.80	$ 47.27	$ 83.21
Average realized price, including financial derivative settlements ($/Bbl)(1)	$ 64.50	$ 78.38	$ 77.78
Average transportation costs ($/Bbl)	$ 0.79	$ 0.77	$ 0.96
Production costs and other cash operating costs ($/Mcfe)			
Average lease operating expenses	$ 0.73	$ 0.78	$ 0.90
Average production taxes(2)	0.27	0.22	0.44
Total production costs	$ 1.00	$ 1.00	$ 1.34
Average general and administrative expenses	$ 0.72	$ 0.77	$ 0.59
Average taxes, other than production and income taxes	$ 0.06	$ 0.05	$ 0.04
Total cash operating costs	$ 1.78	$ 1.82	$ 1.97
Depreciation, depletion and amortization ($/Mcfe)(3)	$ 1.82	$ 1.74	$ 2.94

(1) Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Had we included these premiums in our natural gas average realized prices in 2010, our realized price, including financial derivative settlements, would have decreased by $0.70/Mcf for the year ended December 31, 2010. Premiums related to natural gas derivatives settled during the year ended December 31, 2008 were $21 million. Had we included these premiums in our natural gas average realized prices in 2008, our

realized price, including financial derivative settlements, would have decreased by $0.09/Mcf for the year ended December 31, 2008. We had no premiums related to natural gas derivatives settled during the year ended December 31, 2009, or related to oil derivatives settled during the years ended December 31, 2010, 2009 and 2008.

(2) Production taxes include ad valorem and severance taxes.

(3) Includes $0.06 per Mcfe for both years ended December 31, 2010 and 2009 and $0.05 per Mcfe for the year ended December 31, 2008 related to accretion expense on asset retirement obligations.

Table of Contents

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Our EBIT for 2010 increased $2.1 billion as compared to 2009. The table below shows the significant variances in our financial results in 2010 as compared to 2009:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Higher realized prices in 2010	$ 117	$	$	$ 117
Higher volumes in 2010	27			27
Oil, condensate and NGL				
Higher realized prices in 2010	114			114
Higher volumes in 2010	25			25
Realized and unrealized gains on financial derivatives	(297)			(297)
Other revenues	(25)			(25)
Depreciation, depletion and amortization expense				
Higher depletion rate in 2010		(20)		(20)
Higher production volumes in 2010		(17)		(17)
Production costs				
Lower lease operating expenses in 2010		4		4
Higher production taxes in 2010		(16)		(16)
General and administrative expenses		5		5
Ceiling test charges		2,098		2,098
Impairment of inventory and other assets		25		25
Earnings from unconsolidated affiliate			23	23
Other		8	5	13
Total variances	$ (39)	$ 2,087	$ 28	$ 2,076

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During 2010, revenues increased as compared with 2009 due primarily to higher commodity prices. During the year ended December 31, 2010, we also benefited from an increase in production volumes in our Central and Western divisions and in Brazil.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2010, we recognized net gains of $390 million compared to net gains of $687 million during 2009. Gains or losses each period are based on movements of forward commodity prices relative to the prices in our underlying financial derivative contracts.

Depreciation, depletion and amortization expense. During the year ended December 31, 2010, our depreciation, depletion and amortization expense increased as compared to the same period in 2009 as a result of higher depletion rate and higher production volumes. The year ended December 31, 2009 depletion rate was largely impacted by the ceiling test charges recorded in the first quarter of 2009.

Production costs. Our production costs increased during 2010 as compared to 2009 primarily due to higher production taxes which increased due to higher natural gas and oil revenues.

General and administrative expenses. Our general and administrative expenses decreased during 2010 as compared to the same period in 2009 primarily due to lower payroll and administrative costs to support the business following reorganizations in 2009.

Table of Contents

Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the year ended December 31, 2010, we recorded non-cash ceiling test charges of $25 million to our Egyptian full cost pool as a result of contractual acreage relinquishments in our blocks, and a dry hole drilled in the Tanta block. During the year ended December 31, 2009, we recorded non-cash ceiling test charges of $2.1 billion to our domestic and Brazilian full cost pools as a result of low natural gas and oil prices and to our Egyptian full cost pool as a result of dry hole costs. In the future, we may be required to record additional ceiling test charges related to our Egyptian or Brazilian full cost pools if we continue to add costs to the respective full cost pools, including costs currently excluded from the amortizable base, without a corresponding increase in the value of proved reserves.

Other. Our equity earnings from Four Star in 2010 increased by $23 million as compared to 2009 primarily due to the impact of higher commodity prices partially offset by lower production volumes.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Our EBIT for 2009 increased $99 million as compared to 2008. The table below shows the significant variances in our financial results in 2009 as compared to 2008:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Lower realized prices in 2009	$ (1,011)	$	$	$ (1,011)
Lower volumes in 2009	(119)			(119)
Oil, condensate and NGL				
Lower realized prices in 2009	(203)			(203)
Lower volumes in 2009	(71)			(71)
Realized and unrealized gains on financial derivatives	491			491
Other revenues	(21)			(21)
Depreciation, depletion and amortization expense				
Lower depletion rate in 2009		305		305
Lower production volumes in 2009		54		54
Production costs				
Lower lease operating expenses in 2009		46		46
Lower production taxes in 2009		65		65
General and administrative expenses		(35)		(35)
Ceiling test charges		546		546
Impairment of inventory and other assets		(25)		(25)
Earnings from unconsolidated affiliate			63	63
Other		19	(5)	14
Total variances	$ (934)	$ 975	$ 58	$ 99

Physical sales. During the year ended December 31, 2009, natural gas, oil, condensate and NGL revenues decreased as compared to 2008 due to lower commodity prices and lower production volumes.

Realized and unrealized gains on financial derivatives. During the year ended December 31, 2009, we recognized net gains of $687 million compared to net gains of $196 million during 2008 due to lower natural gas and oil prices in 2009 relative to the commodity prices contained in our derivative contracts.

Depreciation, depletion and amortization expense. During 2009, our depreciation, depletion and amortization expense decreased as a result of a lower depletion rate and lower production volumes. The lower depletion rate is primarily a result of the impact of the ceiling test charges recorded in December 2008 and March 2009.

Production costs. Our production costs decreased during 2009 as compared to the same periods in 2008 primarily due to lower production taxes as a result of lower natural gas and oil revenues and lower lease operating expenses from cost declines in the lower commodity price environment.

General and administrative expenses. Our general and administrative expenses increased during 2009 as compared to the same periods in 2008 primarily due to the reversal of a $20 million accrual in 2008 as a result of a favorable ruling on a legal matter and higher severance costs of approximately $7 million due to reorganizations in 2009.

Ceiling test charges. During the fourth quarter of 2008 and the first quarter of 2009, we recorded total non-cash ceiling test charges of $2.7 billion and $2.1 billion. The calculation of these charges was based on spot commodity prices at the end of each period. In calculating our fourth quarter 2008 ceiling test charges, 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. In the first quarter of 2009, due to low natural gas and oil prices, we experienced a downward price-related reserve revision of approximately 400 Bcfe (primarily in our Arklatex, Raton and Mid-Continent areas) and recorded non-cash ceiling test charges of approximately $2.0 billion in our domestic full cost pool and $28 million in our Brazilian full cost pool.

During the fourth quarter of 2009, primarily due to proved reserve additions, we did not record ceiling test charges in our domestic full cost pool; however, we recorded a $30 million ceiling test charge in our Brazilian full cost pool as a result of lower commodity prices and a downward performance-related reserve revision in our Pescada-Arabaiana Fields.

In accordance with the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we used a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) when performing the ceiling tests. In calculating our ceiling test charges, we are also 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. For more information on the first day 12-month average price used to calculate the ceiling test, see Supplemental Natural Gas and Oil Operations.

During 2009 and 2008, we also recorded non-cash ceiling test charges in our Egyptian full cost pool of $34 million and $9 million. These charges were primarily as a result of dry hole costs on unsuccessful wells drilled during these years.

Impairment of inventory and other assets. In 2009, we recorded a $16 million non-cash charge to reflect the market price we expect to receive upon the sale of certain casing and tubular goods inventory (materials and supplies), which prior to that time, we intended to use in our capital programs. Based on changes to our capital program we decided that we would sell this inventory and use the proceeds to purchase inventory related to our then current capital projects. We also recorded a $9 million non-cash charge as a result of our decision to close our Bluebell processing plant in 2010.

Other. Our equity earnings from Four Star increased by $63 million during the year ended December 31, 2009 as compared to 2008 primarily due to an impairment of the carrying value of our investment of $125 million recorded in 2008, partially offset by the impact of lower commodity prices in 2009.

Table of Contents

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 El Paso s overall price risk. In addition, we continue to manage and liquidate our remaining legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. All of our remaining contracts are subject to counterparty credit and non-performance risks while our remaining mark-to-market contracts are also subject to interest rate exposure.

Natural gas transportation-related contracts. The impact of these accrual-based transportation contracts is based on our ability to use or remarket the contracted pipeline capacity and the amount of production from our Exploration and Production segment. As of December 31, 2010, these contracts require us to pay demand charges of $41 million in 2011 and an average of $40 million between 2012 and 2015. Beginning in 2016, we have an agreement associated with the Ruby Pipeline project that continues through 2021.

Legacy natural gas and power contracts. As of December 31, 2010, these contracts include (i) long-term accrual based supply contracts, including transportation expenses, that obligate us to deliver natural gas to specified power plants and (ii) power contracts in the PJM region through 2016 that we mark-to-market in our results. These contracts are expected to have minimal future impact to us as we have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

Operating Results

Overview. Our overall operating results and analysis for our Marketing segment during each of the three years ended December 31 are as follows:

	2010	2009	2008
		(In millions)	
Income (Loss):			
Production-Related Natural Gas and Oil Derivative Contracts:			
Changes in fair value of options and swaps	$	$	$ (50)
Contracts Related to Legacy Trading Operations:			
Changes in fair value of power contracts	(35)	44	(46)
Natural gas transportation-related contracts:			
Demand charges	(37)	(35)	(35)
Settlements, net of termination payments	33	23	41
Changes in fair value of other natural gas derivative contracts	(10)	(3)	7
Total revenues	(49)	29	(83)
Operating expenses	(2)	(9)	(20)
Operating income (loss)	(51)	20	(103)
Other income, net	1		(1)
EBIT	$ (50)	$ 20	$ (104)

During the years ended December 31, 2010, 2009, and 2008, our results were impacted by changes in the fair value of our legacy power contracts in PJM prior to entering into contracts that eliminated the risks associated with our PJM power contracts. As a result of entering into those contracts, we expect the future earnings impact of the PJM contracts to be solely related to changes in interest rates and credit risk. Also impacting the twelve months ended December 31, 2009, was a $52 million mark-to-market gain related to the adoption of new accounting requirements for our derivative liabilities associated with non-cash collateral (e.g. letters of credit) partially offset by a $27 million loss related to the impact of El Paso s credit standing on our derivative liabilities. During the year ended December 31, 2008, we also recognized (i) mark to market losses on production-related natural gas and crude contracts that we held and managed during that year and (ii) $19 million of revenue related to bankruptcy settlements associated with natural gas derivative contracts.

Table of Contents

Corporate and Other Expenses, Net

Our corporate activities include our general and administrative functions, our emerging midstream business, our remaining power operations, and other miscellaneous businesses. The following is a summary of significant items impacting the EBIT in our corporate and other activities for each of the three years ended December 31:

	2010	2009	2008
		(In millions)	
Change in environmental, legal and other reserves	$ (20)	$ (2)	$ 84
Equity earnings, primarily from power operations	17	5	44
Foreign currency fluctuations	5	19	(19)
Gain (loss) on sale of assets	113	(22)	35
Loss on debt extinguishment	(217)		
Other	28	(17)	(19)
Total EBIT	$ (74)	$ (17)	$ 125

Environmental, Legal and Other Reserves. Our results for all periods presented were impacted by changes in certain legacy litigation and environmental remediation reserves and indemnification liabilities, including adjustments to environmental reserves associated with a non-operating chemical plant in 2010 and 2009. During 2008, we recorded favorable adjustments related to resolving certain legacy litigation matters including $65 million related to our Case Corporation indemnification dispute (see Item 8, Financial Statements and Supplementary Data, Note 12) and $32 million related to the settlement of certain class action matters, partially offset by mark-to-market losses associated with an indemnification related to the sale of a legacy ammonia facility that fluctuates with ammonia prices. During 2010, we eliminated a significant portion of our exposure under this indemnification.

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

Gain (loss) on sale of assets. Additionally in December 2010, we recorded a gain of $110 million in conjunction with the sale of a 50 percent interest in our new midstream joint venture which is comprised of our Altamont gathering and processing midstream assets for $125 million in cash. We own a 50 percent interest in and operate the new joint venture which is accounted for as an equity investment. In 2009, we recorded a loss of $22 million associated with the sale of notes receivable previously received as consideration for the sale of our investment in Porto Velho. In 2008, we recorded gains related to the sale of our share of telecommunication assets and other legacy assets.

Loss on Debt Extinguishment. During 2010, we recorded a total loss of $217 million in conjunction with (i) exchanging approximately $349 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020 and (ii) repurchasing approximately $709 million of our Senior Notes that were due in 2011 through 2016.

Other. During 2010, we recorded $40 million of income due to the receipt of funds previously escrowed and expensed in conjunction with The Coastal Corporation merger. Postretirement benefit costs and general and administrative costs related to legacy acitivities impacted our results during 2010, 2009 and 2008. Losses on our pension plan assets in previous years will be amortized into our net benefit costs in the future, which is anticipated to increase our expense related to this plan in 2011 and beyond. Despite the increased expense, we do not anticipate making any contributions to our primary pension plan in 2011. For further discussion of our postretirement plans and related net benefit cost, see Item 8, Financial Statements and Supplementary Data, Note 13.

Table of Contents

Interest and Debt Expense

Our interest and debt expense for the years ended December 31, 2010, 2009 and 2008 was $1.0 billion, $1.0 billion and $0.9 billion. Our interest and debt expense was flat in 2010 compared to 2009 primarily due to increases in Ruby pipeline project and other financings net of higher AFUDC debt associated with the Ruby project. Additionally, in 2010 we were impacted by changes in our estimates of the allowance for funds used during construction and an increase in the interest rate from 7 percent to 13 percent on the Ruby term loan. During 2009, our interest and debt expense increased as compared to the prior year due primarily to higher interest rates and amortization of discounts related to debt issuances and other financing obligations, net of retirements. See Item 8, Financial Statements and Supplementary Data, Note 11, for a further discussion.

In 2010, we exchanged or repurchased approximately $1.1 billion of debt having rates ranging from 7 percent to 12 percent as further described in Item 8, Financial Statements and Supplementary Data, Note 11. We expect a reduction in annual interest expense of approximately $80 million to $85 million, independent of any other financing actions.

Income Taxes

	Years Ended December 31,		
	2010	2009	2008
		(In millions)	
Income tax expense (benefit)	$386	$(399)	$(245)
Effective tax rate	29%	46%	24%

For a further discussion on our effective tax rate, refer to Item 8, Financial Statements and Supplementary Data, Note 5.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 12.

Liquidity and Capital Resources

Our primary sources of cash include cash flow from operations and funds obtained through long term financings including capital market activities (including executing our financing strategy utilizing our master limited partnership), and bank credit facilities. We also generate cash through project financings (such as Ruby) and asset sales where warranted. We do not typically rely on short-term borrowings to fulfill our liquidity needs. Our primary uses of cash are funding capital expenditure programs, meeting operating needs, paying distributions and dividends and repaying debt when due or repurchasing debt when conditions warrant.

Available Liquidity and Liquidity Outlook for 2011. In 2010 we were successful in funding our capital and liquidity needs. As of December 31, 2010, we had approximately $2.4 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby) partially as a result of 2010 funding actions including (i) the receipt of $2.3 billion in cash in conjunction with contributing ownership interests in SLNG, Elba Express and SNG to our MLP, which funded the acquisitions through the issuance of debt and common units, (ii) the sale of our interests in certain Mexican pipeline and compression assets for approximately $0.3 billion and the receipt of $0.1 billion in cash in conjunction with the sale of a 50 percent interest in our Altamont gathering and processing assets (which are part of our new midstream joint venture) and (iii) finalizing our seven-year amortizing $1.5 billion Ruby financing facility that matures in 2017 under which we borrowed approximately $1.1 billion through December 31, 2010.

Our 2010 full year capital requirements, including our Ruby pipeline project, other pipeline projects and exploration and production expenditures were significant; however, our 2011 requirements decline considerably, and by the end of 2011 we expect a substantial portion of our pipeline backlog will be placed in service. Our 2011 capital programs anticipate planned cash capital expenditures in our operations as follows:

	Total (In billions)
Pipelines	
Maintenance	$ 0.4
Growth[(1)]	1.3
Exploration and Production	1.3
Other[(2)]	0.2
	$ 3.2

(1) Our pipeline growth capital expenditures reflect 100 percent of capital related to our Ruby project. In 2009, we obtained a partner on this project as described below.

(2) Includes planned cash capital expenditures for our Midstream operations of approximately $0.1 billion.

We began construction on our largest pipeline project, our Ruby project, in 2010 and currently expect that the project will be placed in service in July 2011 with an estimated total cost of approximately $3.55 billion. GIP, our 50 percent partner in the Ruby pipeline project, has provided approximately $700 million to support the Ruby project, subject to the satisfaction of various conditions including placing the Ruby pipeline project in service and entering into certain additional firm transportation agreements. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and 50 million common units we own in our MLP. We have also provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, we are required to post letters of credit for any forecasted cost overruns on the project approved by the lender s independent engineer. In this regard, we have posted approximately $0.4 billion in letters of credit to cover the anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender s engineer in subsequent months, then additional letters of credit will be required to be issued pursuant to the Ruby financing agreements. For a further description of this project and our agreement with GIP, see Item 8, Financial Statements and Supplementary Data, Notes 11 and 17.

Table of Contents

We expect our current liquidity sources and operating cash flow to be sufficient to fund our estimated 2011 capital program. In 2011 we also have debt maturities of approximately $500 million which we will pay off as they mature. Additionally, before the end of 2012 we will be required to renew our primary long-term revolving credit facilities (See Item 8, Financial Statements and Supplementary Data, Note 11). The most significant of these facilities are our $1.5 billion EPC revolver and $1.3 billion EPEP revolving credit facilities. As of and for the year ended December 31, 2010, the amount borrowed or utilized for letters of credit under these two facilities aggregated to approximately $0.9 billion. As a result of our 2010 actions, our current available liquidity, hedging program in place on our natural gas and oil production, and planned future actions (including continuing with our MLP drop down strategy as markets permit), we believe we are well positioned to meet our obligations as well as continue with our efforts to strengthen our balance sheet. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements as well as address further changes in the financial and commodity markets. However, there are a number of factors that could impact our plans, including our ability to access the financial markets to fund our long-term capital needs if the financial markets are restricted, or a further decline in commodity prices. If these events occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets, all of which could impact our financial and operating performance.

Overview of 2010 Cash Flow Activities. During 2010, we generated operating cash flow of approximately $1.8 billion, primarily from our pipeline and exploration and production operations. We generated (i) approximately $0.5 billion in total from the sale of certain Mexican pipeline and compression assets, the sale of a 50 percent interest in our Altamont gathering and processing assets (which are part of our new midstream joint venture) and other asset sales, (ii) approximately $1.3 billion as a result of the issuance of MLP common units and (iii) approximately $3.4 billion from debt proceeds including MLP financings as well as Ruby and other consolidated project financings. We utilized these amounts to fund our capital programs, repay amounts outstanding under our various credit facilities and other debt obligations, and pay common and preferred dividends and distributions to our MLP unitholders and holders of our subsidiary preferred stock, among other items. For the year ended December 31, 2010 and 2009, our cash flows from operations are summarized as follows:

	2010	2009
	(In billions)	
Cash Flow from Operations		
Operating activities		
Net income (loss)	$ 0.9	$ (0.5)
Ceiling test charges		2.1
(Gain) loss on long-lived assets	(0.1)	
Other income adjustments	1.3	0.5
Change in other assets and liabilities	(0.3)	
Total cash flow from operations	$ 1.8	$ 2.1
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets and investments	$ 0.5	$ 0.3
Other		0.1
	0.5	0.4
Financing activities		
Net proceeds from the issuance of long-term debt	3.4	1.6
Net proceeds from issuance of noncontrolling interests	1.3	0.2
Net proceeds from issuance of preferred stock of subsidiary	0.1	0.1
	4.8	1.9
Total other cash inflows	$ 5.3	$ 2.3
Cash Outflows		
Investing activities		
Capital expenditures and contributions to equity investments	$ 4.1	$ 2.8
Cash paid for acquisitions		0.1
	4.1	2.9

Financing activities		
Payments to retire long-term debt and other financing obligations	3.1	1.7
Distribution to noncontrolling interest holders	0.1	
Dividends and other	0.1	0.2
	3.3	1.9
Total cash outflows	$ 7.4	$ 4.8
Net change in cash and cash equivalents	$ (0.3)	$ (0.4)

Table of Contents

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 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 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. Those arrangements with a specified dollar amount have a maximum stated value of approximately $0.8 billion, 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 Item 8, Financial Statements and Supplementary Data, Note 11. 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, 2010, we have recorded obligations of $18 million related to our guarantee and 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, 2010, we had outstanding letters of credit of approximately $1.1 billion, including $0.5 billion of letters of credit securing our recorded obligations related to price risk management activities. For additional information on our counterparty credit and nonperformance risk, see Item 8, Financial Statements and Supplementary Data, Note 7. Depending on changes in commodity prices or interest rates, we could be required to post additional margin or may recover margin earlier than anticipated. A 10 percent change in natural gas and power prices would not have had a significant impact on the margin requirements of our derivative contracts as of December 31, 2010.

Interests in Variable Interest Entities

We have interests in several variable interest entities, primarily Ruby. A variable interest entity is a legal entity whose equity owners do not have sufficient equity at risk or characteristics of a controlling financial interest in the entity. We are required to consolidate such entities when we have the ability to control or direct the operating and financial decisions or other activities that are significant to that entity. As of December 31, 2010, there were no significant variable interest entities that we did not consolidate. For additional information regarding our interest in Ruby, see Item 8, Financial Statements and Supplementary Data, Note 17.

Table of Contents

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 summarizes our contractual cash obligations as of December 31, 2010, 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	$ 489	$ 1,561	$ 1,475	$ 10,538	$ 14,063
Interest	986	1,801	1,627	7,591	12,005
Liabilities from price risk management activities	170	218	173	12	573
Other contractual liabilities	144	113	22	26	305
Operating leases	13	23	17	14	67
Other contractual commitments and purchase obligations:					
Transportation and storage	87	174	146	376	783
Other	865	145	77	255	1,342
Total contractual obligations	$ 2,754	$ 4,035	$ 3,537	$ 18,812	$ 29,138

Long-term Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. 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 11.

Liabilities from Price Risk Management Activities. These amounts only include the fair value of our price risk management liabilities. The fair value of our price risk management assets of $326 million as of December 31, 2010 is not reflected in these amounts. We have also excluded margin and other deposits held associated with these contracts from these amounts.

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 fixed as to time and amount. For further information on our expected contributions to our pension and post retirement benefit plans, see Item 8, Financial Statements and Supplementary Data, Note 13. We have also excluded from these amounts liabilities for unrecognized tax benefits of $276 million as of December 31, 2010, since we cannot reasonably estimate the time frame over which these amounts may be resolved.

Operating Leases. For a further discussion of these obligations, see Item 8, Financial Statements and Supplementary Data, Note 12.

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.

Table of Contents

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. Also included are long-term commitments by us related to right of way payments as further discussed in Item 8, Financial Statements and Supplementary Data, Note 12. We have excluded asset retirement obligations and reserves for litigation, environmental remediation and self-insurance claims, other than those disclosed above, as these liabilities are not contractually fixed as to timing and amount.

Table of Contents

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. The process of estimating natural gas and oil reserves, is complex, requiring significant judgment in the evaluation of all available geological, geophysical engineering and economic data. Our proved reserves are estimated at a property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who work closely with the operating groups. These engineers interact with engineering and geoscience personnel in each of our operating areas and accounting and marketing personnel to obtain the necessary data for projecting future production, costs, net revenues and ultimate recoverable reserves. Reserves are reviewed internally with senior management quarterly and presented to our Board of Directors in summary form on an annual basis. Additionally, on an annual basis each property is reviewed in detail by our centralized and operating divisional engineers to ensure forecasts of operating expenses, netback prices, production trends and development timing are reasonable. Our proved reserves are also reviewed by internal committees and the processes and controls used for estimating our proved reserves are reviewed by our 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, conducts an audit of the estimates of a significant portion of our proved reserves. In particular, Ryder Scott Company, L.P. conducted an audit of our estimates of proved reserves as of December 31, 2010.

As of December 31, 2010, of our total consolidated proved reserves, 40 percent were undeveloped (38 percent including Four Star) and 12 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. For more information regarding price sensitivities related to our estimated proved reserves, see Part I, Item 1. Business, Natural Gas and Oil Properties.

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. For a further discussion of these costs by country, see Part II, Item 8, Financial Statements and Supplementary Data, Supplemental Natural Gas and Oil Operations.

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 deferred income taxes, are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted at 10 percent, plus the cost of unproved natural gas and oil properties not being amortized less related income tax effects. On December 31, 2009, we adopted the provisions of the SEC s final rule on Modernization of Oil and Gas Reporting. Among other things, the final rule revised the definition of proved reserves and required us to use a first day 12-month average price in calculating the ceiling test and estimating proved reserves rather than a period end spot price as required in prior periods. If the discounted future net cash flows 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 future net cash flows.

Cost-Based Regulation. We account for our regulated operations in accordance with current Financial Accounting Standard Board (FASB) accounting standards for rate-regulated operations. 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 or if regulatory liabilities are probable of being refunded to our customers 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 accounting standards related to regulated operations, 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 Environmental and Legal Reserves, Guarantees and Indemnifications. We accrue environmental and legal reserves when our assessments indicate that it is probable that a liability has been incurred 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, 2010, we had accrued approximately $45 million for legal matters and approximately $173 million for environmental matters, which has not been reduced by $19 million for amounts to be paid directly under government sponsored programs or through settlement arrangements. Our environmental estimates range from approximately $173 million to approximately $365 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 $0.8 billion. As of December 31, 2010, we have recorded obligations of $18 million related to our guarantee and indemnification

Table of Contents

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, 2010, our pension plans were under funded by $170 million and our other postretirement benefit plans were under funded by $394 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 expected future lives of inactive 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, 2010, we had deferred net losses of approximately $682 million, net of income taxes, in accumulated other comprehensive income related to our pension and other postretirement benefits. 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, 2010 (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	$ (7)	$ 173	$ 1	$ 52
Expected return on plan assets	(20)		(2)	
Rate of compensation increase	2	(7)		
Health care cost trends			3	(49)
One percent decrease in:				
Discount rates	$ 7	$ (202)	$ (3)	$ (56)
Expected return on plan assets[1]	20		2	
Rate of compensation increase	(1)	6		
Health care cost trends			(4)	43

(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 change significantly.

The estimates for our net benefit expense or income are partially based on the expected return on pension plan assets. We use a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred over three years, after which they are considered for inclusion in net benefit expense or income. If we used the fair value of our plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, our net benefit expense would have been $15 million higher for the year ended December 31, 2010.

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 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, 2010:

		Change in Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 237	$ 33	$ (204)	$ 434	$ 197
Other commodity-based derivatives	(423)	(422)	1	(426)	(3)
Total	$ (186)	$ (389)	$ (203)	$ 8	$ 194

Another significant assumption is 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, 2010:

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 237	$ 237	$	$ 237	$
Other commodity-based derivatives	(423)	(414)	9	(432)	(9)
Total	$ (186)	$ (177)	$ 9	$ (195)	$ (9)

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 considering cash collateral we have posted with our counterparties.

The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from potential changes in credit risk at December 31, 2010:

		Change in Credit Risk			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives	$ 237	$ 235	$ (2)	$ 239	$ 2
Other commodity-based derivatives	(423)	(419)	4	(429)	(6)
Total	$ (186)	$ (184)	$ 2	$ (190)	$ (4)

88

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 reflect our assessment of tax positions taken, and the resulting tax basis, and reflect our conclusions about which positions 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 or through a structured sale which would not result in any additional deferred 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. This estimate 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. Our assessment of fair value including, but not limited to estimates 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. During the years ended December 31, 2010, 2009 and 2008 we recorded impairments of $10 million, $30 million and $41 million related to our long-lived assets and other assets. We recorded impairments and losses on our investments in and advances to unconsolidated affiliates of $127 million during the year ended December 31, 2008. Future changes in the economic and business environment can impact our assessments of potential impairments.

Principles of Consolidation. For entities where both we and third parties have equity or other interests, we perform an evaluation to determine which party should consolidate the entity. As part of this evaluation, we are required to determine whether or not the entity is considered a variable interest entity (VIE) and ultimately which party is considered the primary beneficiary and/or who controls the entity's operating and financial decisions. As part of these evaluations, there is a significant amount of judgment involved in evaluating the entities' contractual relationships, the relative nature of the third party's and our interests in the entities, and the ability to control or direct its activities. If different judgment were applied, our accounting treatment and financial statement presentation for these entities could be significantly impacted. For a further discussion of our significant variable interest entities and investments in unconsolidated affiliates as of December 31, 2010, see Item 8. Financial Statements and Supplementary Data, Notes 17 and 18.

Table of Contents

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 amounts at which we sell our natural gas and oil in our Exploration and Production segment, affect the value of 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 also affect amounts at which we sell our natural gas and oil production, the fair values of any related derivative products and 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 result in increases or decreases in the unrealized value of our derivative positions; and
- Changes in interest rates used to discount liabilities result in higher or lower accretion expense over time.

Where practical, we manage these various 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 Item 8, Financial Statements and Supplementary Data, Notes 1 and 7.

Commodity Price Risk

Production-Related Derivatives

In our Exploration and Production segment 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 production.

Other Commodity-Based Derivatives

In our Marketing segment, we have long-term natural gas and power derivative contracts which include forwards, swaps, options and futures that we either intend to manage until their expiration or seek opportunities to liquidate to the extent it is economical and prudent. We utilize a sensitivity analysis to manage the commodity price risk associated with these contracts.

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, 2010	$ 237	$ 33	$ (204)	$ 434	$197
December 31, 2009	$ 127	$ (29)	$ (156)	$ 290	$163
Other commodity-based derivatives net assets (liabilities)					
December 31, 2010	$(423)	$(422)	$ 1	$(426)	$ (3)
December 31, 2009	$(508)	$(517)	$ (9)	$(500)	$ 8

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, 2010								December 31, 2009	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair Value	Carrying Amounts	Fair Value
	2011	2012	2013	2014	2015	Thereafter	Total			
						(In millions)				
Fixed rate long-term debt and other obligations[(1)]	$458	$394	$ 197	$451	$755	$9,631	$11,886	$12,583	$11,705	$12,170
Average interest rate	9.0%	6.8%	14.7%	7.4%	5.5%	7.5%				

Variable rate long-term debt and other obligations[1]	$ 30	$888	$ 76	$ 82	$185	$ 859	$ 2,120	$ 2,103	$ 2,163	$ 1,981
Average interest rate	3.9%	2.1%	3.0%	3.0%	4.3%	2.3%				

(1) Includes current portion.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

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

Table of Contents

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, 2010. 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, 2010. The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

Table of Contents

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 (the Company) as of December 31, 2010 and 2009, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2010. 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 has a 50% interest) as of December 31, 2010 and 2009 and for each of the three years in the period ended December 31, 2010 and Four Star Oil & Gas Company (a corporation in which the Company has approximately a 49% interest) for the year ended December 31, 2008 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 as of the years and for the periods herein referred to, is based solely on the reports of the other auditors. In the consolidated financial statements, the Company s investments in unconsolidated affiliates includes approximately $866 million and $674 million from Citrus Corp. and Subsidiaries as of December 31, 2010 and 2009, respectively, and the Company s earnings from unconsolidated affiliates includes approximately $90 million and $65 million for the years ended December 31, 2010 and 2009, respectively, from Citrus Corp. and Subsidiaries and approximately $147 million for the year ended December 31, 2008, from Citrus Corp. and Subsidiaries and Four Star Oil & Gas Company combined, all of 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 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 December 31, 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2010, 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 28, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 28, 2011

Table of Contents

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, 2010, 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, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2010 consolidated financial statements of El Paso Corporation and our report dated February 28, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 28, 2011

Table of Contents

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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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 25, 2011

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Stockholders of Four Star Oil & Gas Company:

In our opinion, the consolidated balance sheet 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 the results of their operations and their cash flows for the year then ended 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 audit. We conducted our audit 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 audit provides 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

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Operating revenues			
Pipelines	$ 2,820	$ 2,767	$ 2,684
Exploration and Production	1,789	1,828	2,762
Marketing	(49)	29	(83)
Corporate and other	56	7	
	4,616	4,631	5,363
Operating expenses			
Cost of products and services	218	207	245
Operation and maintenance	1,235	1,235	1,186
Ceiling test charges	25	2,123	2,669
(Gain) loss on long-lived assets	(83)	22	4
Depreciation, depletion and amortization	942	867	1,205
Taxes, other than income taxes	236	228	284
	2,573	4,682	5,593
Operating income (loss)	2,043	(51)	(230)
Earnings from unconsolidated affiliates	188	67	48
Loss on debt extinguishment	(217)		
Other income	333	144	94
Other expenses	(6)	(25)	(32)
Interest and debt expense	(1,031)	(1,008)	(914)
Income (loss) before income taxes	1,310	(873)	(1,034)
Income tax expense (benefit)	386	(399)	(245)
Net income (loss)	924	(474)	(789)
Net income attributable to noncontrolling interests	(166)	(65)	(34)
Net income (loss) attributable to El Paso Corporation	758	(539)	(823)
Preferred stock dividends of El Paso Corporation	(37)	(37)	(37)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 721	$ (576)	$ (860)
Basic earnings (loss) per common share			
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 1.03	$ (0.83)	$ (1.24)
Diluted earnings (loss) per common share			

Net income (loss) attributable to El Paso Corporation s common stockholders	$ 1.00	$ (0.83)	$ (1.24)

See accompanying notes.

Table of Contents

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

	December 31, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents (includes $31 in 2010 and $149 in 2009 held by variable interest entities)	$ 347	$ 635
Accounts and notes receivable		
Customer, net of allowance of $4 in 2010 and $8 in 2009	333	346
Affiliates	7	92
Other	160	115
Materials and supplies	169	175
Assets from price risk management activities	265	221
Deferred income taxes	165	298
Other	106	126
Total current assets	1,552	2,008
Property, plant and equipment, at cost		
Pipelines (includes $3,232 in 2010 and $1,179 in 2009 held by variable interest entities)	22,385	19,722
Natural gas and oil properties, at full cost	21,692	20,846
Other	416	314
	44,493	40,882
Less accumulated depreciation, depletion and amortization	23,421	22,987
Total property, plant and equipment, net	21,072	17,895
Other assets		
Investments in unconsolidated affiliates	1,673	1,718
Assets from price risk management activities	61	123
Other	912	761
	2,646	2,602
Total assets	$ 25,270	$ 22,505

See accompanying notes.

Table of Contents

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

	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 610	$ 459
Affiliates	9	7
Other	386	424
Short-term financing obligations, including current maturities	489	477
Liabilities from price risk management activities	176	269
Asset retirement obligations	63	158
Accrued interest	202	208
Other	630	684
Total current liabilities	2,565	2,686
Long-term financing obligations, less current maturities	13,517	13,391
Other long-term liabilities		
Liabilities from price risk management activities	397	462
Deferred income taxes	568	339
Other	1,461	1,491
	2,426	2,292
Commitments and contingencies (Note 12)		
Preferred stock of subsidiaries	698	145
Equity		
El Paso Corporation s 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 719,743,724 shares in 2010 and 716,041,302 shares in 2009	2,159	2,148
Additional paid-in capital	4,484	4,501
Accumulated deficit	(2,434)	(3,192)
Accumulated other comprehensive loss	(751)	(718)
Treasury stock (at cost); 15,492,605 shares in 2010 and 14,761,654 shares in 2009	(291)	(283)
Total El Paso Corporation stockholders equity	3,917	3,206
Noncontrolling interests	2,147	785
Total equity	6,064	3,991

Total liabilities and equity	$ 25,270	$ 22,505

See accompanying notes.

Table of Contents

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

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities			
Net income (loss)	$ 924	$ (474)	$ (789)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion and amortization	942	867	1,205
Ceiling test charges	25	2,123	2,669
Deferred income tax expense (benefit)	374	(427)	(172)
Earnings from unconsolidated affiliates, adjusted for cash distributions	(124)	21	132
(Gain) loss on long-lived assets	(83)	22	4
Loss on debt extinguishment	217		
Other non-cash income items	(129)	35	28
Asset and liability changes			
Accounts and notes receivable	132	142	129
Change in deferred purchase price from accounts receivable sales	(89)		
Change in price risk management activities, net	(181)	(46)	(461)
Accounts payable	22	(140)	(88)
Change in margin and other deposits	(35)	22	24
Other asset changes	(27)	(74)	(32)
Other liability changes	(123)	44	(279)
Net cash provided by operating activities	1,845	2,115	2,370
Cash flows from investing activities			
Capital expenditures and contributions to equity investments	(4,073)	(2,810)	(2,757)
Cash paid for acquisitions, net of cash acquired	(51)	(130)	(362)
Net proceeds from the sale of assets and investments	463	351	682
Net change in restricted cash	6	49	39
Other	2	(41)	50
Net cash used in investing activities	(3,653)	(2,581)	(2,348)
Cash flows from financing activities			
Net proceeds from issuance of debt and other financing obligations	3,360	1,618	4,641
Payments to retire debt and other financing obligations	(3,127)	(1,668)	(3,679)
Net proceeds from issuance of noncontrolling interests	1,340	212	15
Distributions to noncontrolling interest holders	(96)	(48)	(29)
Net proceeds from the issuance of preferred stock of subsidiary	120	145	
Distributions to holders of preferred stock of subsidiary	(21)		
Dividends paid	(65)	(177)	(157)
Repurchase of common shares			(77)
Other	9	(5)	3
Net cash provided by financing activities	1,520	77	717

Change in cash and cash equivalents	(288)	(389)	739
Cash and cash equivalents			
Beginning of period	635	1,024	285
End of period	$ 347	$ 635	$ 1,024
Supplemental cash flow information			
Interest paid, net of amounts capitalized	$ 956	$ 968	$ 914
Income tax payments (refunds)	(17)	(24)	12

See accompanying notes.

Table of Contents

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

	Year Ended December 31,					
	2010		2009		2008	
	Shares	Amount	Shares	Amount	Shares	Amount
El Paso Corporation stockholders equity:						
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	716	2,148	712	2,138	709	2,128
Other, including stock-based compensation	4	11	4	10	3	10
Balance at end of year	720	2,159	716	2,148	712	2,138
Additional paid-in capital:						
Balance at beginning of year		4,501		4,612		4,699
Dividends		(65)		(149)		(163)
Other, including stock-based compensation		48		38		76
Balance at end of year		4,484		4,501		4,612
Accumulated deficit:						
Balance at beginning of year		(3,192)		(2,653)		(1,834)
Net income (loss) attributable to El Paso Corporation		758		(539)		(823)
Other						4
Balance at end of year		(2,434)		(3,192)		(2,653)
Accumulated other comprehensive loss:						
Balance at beginning of year		(718)		(532)		(272)
Other comprehensive loss		(33)		(186)		(263)
Other						3
Balance at end of year		(751)		(718)		(532)
Treasury stock, at cost:						
Balance at beginning of year	(15)	(283)	(14)	(280)	(9)	(191)
Share repurchases					(5)	(77)
Stock-based and other compensation		(8)	(1)	(3)		(12)
Balance at end of year	(15)	(291)	(15)	(283)	(14)	(280)
Total El Paso Corporation stockholders equity at end of year		3,917		3,206		4,035
Noncontrolling interests:						

Balance at beginning of year	785	561	565
Issuance of noncontrolling interests	1,340	212	15
Distributions to noncontrolling interests	(96)	(48)	(29)
Net income attributable to noncontrolling interests (Note 14)	118	60	34
Other			(24)
Balance at end of year	2,147	785	561
Total equity at end of year	$ 6,064	$ 3,991	$ 4,596

See accompanying notes.

Table of Contents

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Net income (loss)	$ 924	$ (474)	$ (789)
Pension and postretirement obligations:			
Unrealized actuarial gains (losses) arising during period (net of income taxes of $24 in 2010, $11 in 2009 and $288 in 2008)	(46)	36	(527)
Reclassifications of actuarial gains during period (net of income taxes of $25 in 2010, $16 in 2009 and $8 in 2008)	46	27	16
Cash flow hedging activities:			
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $24 in 2010, $6 in 2009 and $106 in 2008)	(40)	11	191
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $4 in 2010, $146 in 2009 and $31 in 2008)	7	(260)	57
Other comprehensive (loss)	(33)	(186)	(263)
Comprehensive income (loss)	891	(660)	(1,052)
Comprehensive income attributable to noncontrolling interests	(166)	(65)	(34)
Comprehensive income (loss) attributable to El Paso Corporation	$ 725	$ (725)	$ (1,086)

See accompanying notes.

Table of Contents

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 United States (U.S.) generally accepted accounting principles (GAAP) and include the accounts of all consolidated 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, none of which impacted our reported net income (loss) or stockholders equity.

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control or direct the policies, decisions or activities of an entity. 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) and follow the Financial Accounting Standards Board s (FASB) accounting standards for regulated operations. Under these standards, we record regulatory assets and liabilities that would not be recorded for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges or credits that are expected to 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.

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 collectability and establish or adjust our allowance as necessary using the specific identification method.

Property, Plant and Equipment

Pipelines and Other (Excluding Natural Gas and Oil Properties). Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and, an equity return component in our regulated businesses. We capitalize 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 10.

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 are not recoverable in our rates under current FERC policies.

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, as defined by the FERC. We include gains or losses on dispositions of operating units in operations and maintenance expense in our income statements.

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 as 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 countries where a natural gas or oil reserve base exists, we transfer unproved property costs to the amortizable base when we have completed an evaluation of the unproved properties. 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 deferred income taxes, are limited to a ceiling based on the present value of future net revenues from proved reserves, discounted at 10 percent, plus the cost of unproved natural gas and oil properties not being amortized less related income tax effects. We perform this ceiling test calculation each quarter. Prior to December 31, 2009, we utilized end of period spot prices to determine future net revenues. As a result of our adoption of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, and we now utilize a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) when performing the ceiling test. We are also 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. If total capitalized costs exceed the ceiling, we are required to write-down our capitalized costs to the ceiling. Any required write-down is included as a ceiling test charge on our income statement and as an increase to accumulated depreciation, depletion and amortization on our balance sheet. The present value of future net revenues used for 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 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 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. If 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.

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 to participants and retirees. These contributions are invested until the benefits are paid to plan participants. The net benefit cost of these plans is recorded in our income statement and is a function of many factors including benefits earned during the year by plan participants (which is a function of factors such as 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 benefit plans, see Note 13.

In accounting for our pension and other postretirement benefit plans, we record an asset or liability based on the over funded or under funded status of each plan. 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 all other operations until those gains and losses are recognized in the income statement.

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 based on contractual 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. 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. For contracts with step-up or step-down rate provisions, that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. Gas not used in 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 the FERC allows us to 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 natural gas liquids. 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 Environmental Protection Agency 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 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 exposure on our long-term debt. We also hold other derivatives not intended to hedge these exposures.

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 is 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 on counterparties where we have a legal right of offset.

When we enter into derivative contracts related to our price risk management activities, we may designate the derivative as either a cash flow hedge or a fair value hedge. Cash flow hedges 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. Changes in the fair value of these hedges are deferred in accumulated other comprehensive income or loss to the extent they are effective and then recognized in revenues or expenses when the hedged transactions occur. Ineffectiveness related to our cash flow hedges is recognized in earnings as it occurs. Fair value hedges are entered into to protect the fair value of a recognized asset, liability or firm commitment. Changes in the fair value of these hedges are recognized in earnings as offsets to the changes in fair value of the related hedged assets, liabilities or firm commitments.

Table of Contents

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 generally 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. In our balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 7 for a further discussion of our price risk management activities.

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.

Accounting for 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 initially 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 asset to which that liability relates. An ongoing expense is 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 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 awards 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 15.

2. Acquisitions and Divestitures

Acquisitions. During 2010, 2009 and 2008, we acquired the following assets:

	2010	2009 (In millions)	2008
Domestic natural gas and oil properties (Exploration and Production) [1]	$ 51	$ 92	$ 61
Gulf LNG (Pipelines)			295
Other		38	6
Total	$ 51	$ 130	$ 362

(1) Includes producing properties of approximately $87 million located primarily in Altamont in Utah in 2009 and producing properties of $51 million in 2008.

Gulf LNG. In February 2008, we paid approximately $295 million to complete the acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, a LNG terminal which is currently under construction in Pascagoula, Mississippi. The terminal is expected to be placed in service in late 2011. In addition, we have a commitment to loan Gulf LNG up to $150 million under which we have advanced approximately $83 million and $56 million as of December 31, 2010 and 2009. Our partners in this project have a commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

Divestitures. During 2010, 2009 and 2008, we sold a number of assets and investments the proceeds of which are as follows:

	2010	2009 (In millions)	2008
Pipelines	$ 306	$ 65	$ 2
Exploration and Production	29	93	637
Corporate and Other	128	190	36
Total[1]	$ 463	$ 348	$ 675

(1) During the years ended December 31, 2009 and 2008, our sales proceeds were increased by $3 million and $7 million to exclude any returns of capital on our investments in unconsolidated affiliates and cash transferred with the assets sold. Amounts are also net of costs incurred in preparing assets for disposal.

Our 2010 divestitures primarily related to (i) the sale for approximately $300 million in cash of our interests in certain Mexican pipeline and compression assets and (ii) the sale for $125 million in cash of a 50 percent interest in our Altamont gathering and processing assets (which are part of our new midstream joint venture), included in Corporate and Other above. In conjunction with these sales, we recorded pretax gains in 2010 of approximately $80 million in earnings from unconsolidated affiliates on the Mexico sale and $110 million on the midstream sale. During each of the three years ended December 31, 2010, 2009, and 2008, we also sold natural gas and oil properties, pipeline assets or related facilities, legacy international power investments and other assets.

3. Ceiling Test Charges

We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the years ended December 31, 2010, 2009, and 2008, we recorded the following ceiling test charges:

	2010	2009 (In millions)	2008
Full cost pool:			

U.S.	$	$ 2,031	$ 2,181
Brazil		58	479
Egypt	25	34	9
Total	$ 25	$ 2,123	$ 2,669

4. Other Income and Other Expenses

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

	2010	2009 (In millions)	2008
Other Income			
Allowance for equity funds used during construction (Note 10)	$ 246	$ 95	$ 54
Recovery of escrowed funds	40		
Interest income	21	26	19
Other	26	23	21
Total	$ 333	$ 144	$ 94
Other Expenses			
Foreign currency losses	$	$	$ 28
Loss on sale of Porto Velho notes receivable		22	
Other	6	3	4
Total	$ 6	$ 25	$ 32

5. Income Taxes

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

	2010	2009 (In millions)	2008
Pretax Income (Loss)			
U.S	$ 1,236	$ (771)	$ (569)
Foreign	74	(102)	(465)
	$ 1,310	$ (873)	$ (1,034)
Components of Income Tax Expense (Benefit)			
Current			
Federal	$ (4)	$ (1)	$ (36)
State	5	24	(38)
Foreign	11	5	1
	12	28	(73)
Deferred			
Federal	385	(400)	(238)
State	(5)	(26)	27
Foreign	(6)	(1)	39

	374	(427)	(172)
Total income tax expense (benefit)	$ 386	$ (399)	$ (245)

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

	2010	**2009**	**2008**
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	$ 459	$ (305)	$ (362)
Increase (decrease)			
Income attributable to nontaxable noncontrolling interests	(58)	(23)	(12)
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(34)	(23)	(41)
Healthcare legislation Elimination of Medicare subsidy	18		
Sales and write-offs of foreign investments	(19)	(88)	(50)
Valuation allowances	6	47	202
State income taxes, net of federal income tax effect	2	44	(6)
Foreign income (loss) taxed at different rates	4	(42)	23
Other	8	(9)	1
Income tax expense (benefit)	$ 386	$ (399)	$ (245)
Effective tax rate	29%	46%	24%

Table of Contents

In 2009, our effective tax rate was higher than the statutory rate primarily due to recording $88 million of income tax benefit relating to a U.S. tax loss on the liquidation of certain foreign entities. Following the 2009 sale of the remaining significant international power projects, these entities had no liquidating value. As these entities had tax basis, the liquidation resulted in a tax loss. 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.

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 or through a structured sale which would not result in any additional deferred tax liabilities. At December 31, 2010, the undistributed earnings of our unconsolidated affiliates for which we expect to receive a dividends received deduction was approximately $451 million.

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

	2010	2009
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$ 2,132	$ 2,193
Investments in affiliates	124	193
Regulatory and other assets	96	77
Total deferred tax liability	2,352	2,463
Deferred tax assets		
Net operating loss and tax credit carryovers		
Federal	1,180	1,399
State	66	77
Foreign	219	202
Benefits and compensation	293	308
Price risk management activities	158	258
Legal and other reserves	164	240
Other	269	324
Valuation allowance	(391)	(384)
Total deferred tax asset	1,958	2,424
Net deferred tax liability	$ 394	$ 39

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, 2010, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately $83 million.

Unrecognized Tax Benefits. 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 2007. For years in which our returns are still subject to review, our unrecognized tax benefits 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. The following table shows the change in our unrecognized tax benefits:

	2010	2009
	(In millions)	
Amount at January 1	$ 260	$ 173
Additions:		
Tax positions taken in prior years	19	(2)
Tax positions taken in current year	7	87
Foreign currency fluctuations	1	3
Reductions:		
Tax positions taken in prior years		(1)
Settlements with taxing authorities	(6)	4
Statute of limitations expiration	(5)	(4)
Amount at December 31	$ 276	$ 260

As of December 31, 2010, and 2009, approximately $275 million and $258 million (net of federal tax benefits) of unrecognized tax benefits and associated interest and penalties 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 classify interest and penalties related to unrecognized tax benefits as income taxes in our financial statements. During 2010, 2009 and 2008, we recognized in our consolidated statements of income $(1) million, $3 million and $4 million in interest and penalties related to unrecognized tax benefits. As of December 31, 2010 and 2009, we had $51 million and $52 million of accrued interest and penalties in our consolidated balance sheets.

Tax Credit and Net Operating Loss Carryovers. As of December 31, 2010, we have U.S. federal alternative minimum tax credits of $290 million that carryover indefinitely. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2010:

	Carryover Period				
	2011	2012-2015	2016-2020	2021-2030	Total
			(In millions)		
U.S. federal net operating loss	$ 9	$ 3	$ 21	$ 2,842	$ 2,875
State net operating loss	52	290	787	828	$ 1,957

We also had $556 million of foreign net operating loss carryovers and $74 million of foreign capital loss carryovers, the majority of which carryover indefinitely. Usage of our U.S. federal carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

Valuation Allowances. Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on the 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.

Table of Contents

As of December 31, 2010, our valuation allowance primarily relates to deferred tax assets recorded on state and foreign net operating losses and temporary differences. The valuation allowance related to our Brazilian and Egyptian net operating losses was established prior to 2010 primarily as a result of changes in the worldwide economic conditions that created uncertainty in our outlook as to future taxable income in those particular tax jurisdictions. In 2010, we increased our valuation allowance by $10 million on deferred tax assets associated with Brazil and Egypt net operating losses and reduced our valuation allowance by $3 million on deferred tax assets associated with expiring federal and state net operating losses. 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

Basic and diluted earnings (loss) per common share was as follows for the three years ended December 31:

	2010		2009		2008	
	Basic	**Diluted**	**Basic**	**Diluted**	**Basic**	**Diluted**
	(In millions, except per share amounts)					
Net income (loss) attributable to El Paso Corporation	$ 758	$ 758	$ (539)	$ (539)	$ (823)	$ (823)
Preferred stock dividends of El Paso Corporation	(37)		(37)	(37)	(37)	(37)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 721	$ 758	$ (576)	$ (576)	$ (860)	$ (860)
Weighted average common shares outstanding	698	698	696	696	696	696
Effect of dilutive securities:						
Options and restricted stock		6				
Convertible preferred stock		58				
Weighted average common shares outstanding and dilutive securities	698	762	696	696	696	696
Basic and diluted earnings per common share:						
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 1.03	$ 1.00	$ (0.83)	$ (0.83)	$ (1.24)	$ (1.24)

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 net income attributable to El Paso Corporation per common share is antidilutive. Potentially dilutive securities consist of employee stock options, restricted stock, convertible preferred stock and trust preferred securities. For the year ended December 31, 2010, our trust preferred securities and certain of our employee stock options were antidilutive. For the years ended December 31, 2009 and 2008, we incurred losses attributable to El Paso Corporation and, accordingly, excluded all potentially dilutive securities from the determination of diluted earnings per share. For a discussion of our capital stock activity, our stock-based compensation arrangements, and other instruments noted above, see Notes 14 and 15.

Table of Contents

7. Financial Instruments

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

	As of December 31,			
	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$14,006	$14,686	$13,868	$14,151
Marketable securities in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(186)	(186)	(381)	(381)
Interest rate derivatives	(61)	(61)	(6)	(6)
Other	(11)	(11)	(14)	(14)

As of December 31, 2010 and 2009, the carrying amounts of cash and cash equivalents, short-term borrowings, accounts receivable and accounts payable represent 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 the nature of their interest rates and our assessment of the 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.

Our derivative financial instruments are further described below:

Production-Related Commodity Based Derivatives. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of natural gas and oil production through the use of natural gas and oil swaps, basis swaps and option contracts. As of December 31, 2010 and 2009, none of these contracts are designated as accounting hedges. In 2008, we had designated certain of these derivatives as cash flow hedges. As of December 31, 2010 and 2009, we have production-related derivatives on 283 TBtu and 313 TBtu of natural gas and 12,240 MBbl and 4,016 MBbl of oil.

Other Commodity-Based Derivatives. In our Marketing segment, we have long-term natural gas and power derivative contracts that include forwards, swaps and options that we will either manage until their expiration or liquidate to the extent it is economical and prudent to do so. None of these derivatives are designated as accounting hedges. As of December 31, 2010 and 2009, these contracts include (i) those that obligate us to sell natural gas to power plants and have expiration dates ranging from 2012 to 2019, with expected obligations ranging from 12,550 MMBtu/d to 95,000 MMBtu/d and (ii) those that require us to swap locational differences in power prices between three power plants in the PJM eastern region with the PJM west hub on approximately 3,700 GWh from 2011 to 2012, 2,400 GWh for 2013 and 1,700 GWh from 2014 to April 2016. These contracts also 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. For these natural gas and power contracts, we have entered into contracts to economically mitigate our exposure to commodity price changes and locational price differences on substantially all of these volumes.

Interest Rate Derivatives. We have long-term debt with variable interest rates that exposes us to changes in market-based interest rates. As of December 31, 2010 and 2009, we had interest rate swaps, which are designated as cash flow hedges that effectively convert the interest rate on approximately $1.3 billion and $169 million of debt from a floating LIBOR interest rate to a fixed interest rate. Approximately $1.1 billion of the debt hedged as of December 31, 2010, relates to debt commitments associated with our Ruby pipeline project that begin accruing interest on July 1, 2011 and have termination dates ranging from June 2013 to June 2017. These termination dates correspond to the estimated principal outstanding on the Ruby debt over the term of these swaps. For a further discussion of our Ruby financing, see Note 11.

We also have long-term debt with fixed interest rates that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps designated as fair value hedges to protect the value of certain of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments. We record changes in the fair value of these derivatives in interest expense which is offset by changes in the fair value of the related hedged items. As of December 31, 2010 and 2009, these interest rate swaps converted the interest rate on approximately $184 million and $218 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%.

Table of Contents

Cross-Currency Derivatives. During 2009, we settled cross-currency swaps that were designated as fair value hedges of Euro-denominated debt. For the year ended December 31, 2009, these swaps increased our interest expense by approximately $3 million and decreased our other income by approximately $26 million as result of changing interest and foreign currency rates during 2009.

Fair Value Measurements. We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument, data available for similar instruments in similar markets or other assumptions related to estimates of future settlements of the instrument.

We separate the fair values of our financial instruments 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 fair value. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument. 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 in non-qualified compensation plans.

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 interest rate swaps, 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. These fair values also consider our creditworthiness or that of our counterparties (adjusted for collateral related to our asset positions).

Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but also reflect adjustments for being in less liquid markets or having longer contractual terms. Primarily included in this level are our power-related derivatives and certain of our remaining natural gas derivatives. To determine the fair value of these instruments, we obtain pricing data from third party pricing sources and develop an estimate of forward prices that we believe market participants would use based on the liquidity of the underlying forward markets over the contractual terms. 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 our asset positions).

Financial Statement Presentation. The following table presents the fair value of our financial instruments at December 31, 2010 and 2009 (in millions). Our marketable securities in non-qualified compensation plans and other are reflected at fair value on our balance sheets as other assets, other current liabilities and other liabilities.We net our derivative assets and liabilities for counterparties where we have a legal right of offset and classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. At December 31, 2010 and 2009, cash collateral held was not material.

	December 31, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ 373	$	$ 373	$	$ 239	$	$ 239
Other natural gas derivatives		139	18	157		495	24	519
Power-related derivatives			31	31			57	57
Total commodity-based derivative assets		512	49	561		734	81	815
Interest rate derivatives designated as hedges								
Cash flow hedges						1		1
Fair value hedges		8		8		10		10
Impact of master netting arrangements		(229)	(14)	(243)		(459)	(23)	(482)
Total price risk management assets	$	$ 291	$ 35	$ 326	$	$ 286	$ 58	$ 344
Marketable securities in non-qualified compensation plans	20			20	20			20
Total net assets	$ 20	$ 291	$ 35	$ 346	$ 20	$ 286	$ 58	$ 364
Liabilities								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ (136)	$	$ (136)	$	$ (112)	$	$ (112)
Other natural gas derivatives		(162)	(90)	(252)		(542)	(136)	(678)
Power-related derivatives			(359)	(359)			(406)	(406)
Total commodity-based derivative liabilities		(298)	(449)	(747)		(654)	(542)	(1,196)
Interest rate derivatives designated as hedges								
Cash flow hedges		(69)		(69)		(17)		(17)
Impact of master netting arrangements		229	14	243		459	23	482
Total price risk management liabilities	$	$ (138)	$ (435)	$ (573)	$	$ (212)	$ (519)	$ (731)
Other			(12)	(12)			(31)	(31)

Total net liabilities	$	$ (138)	$ (447)	$ (585)	$	$ (212)	$ (550)	$ (762)
Total	$ 20	$ 153	$ (412)	$ (239)	$ 20	$ 74	$ (492)	$ (398)

Table of Contents

The following table presents the changes in our financial assets and liabilities included in Level 3 for the years ended December 31, 2010 and 2009 (in millions):

	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues[1]	Change in Fair Value Reflected in Operating Expenses[2]	Settlements, Net	Balance at End of Period
December 31, 2010					
Assets	$ 58	$ (21)	$	$ (2)	$ 35
Liabilities	(550)	(22)	(3)	128	(447)
Total	$ (492)	$ (43)	$ (3)	$ 126	$ (412)
December 31, 2009					
Assets	$ 103	$ (38)	$	$ (7)	$ 58
Liabilities	(751)	75	21	105	(550)
Total	$ (648)	$ 37	$ 21	$ 98	$ (492)

(1) Includes approximately $41 million of net losses and $11 million of net gains that had not been realized through settlements for the year ended December 31, 2010 and 2009.

(2) Includes approximately $2 million of net losses and $18 million of net gains that had not been realized through settlements for the year ended December 31, 2010 and 2009.

Below are the impacts of our commodity-based and interest rate derivatives to our income statement and statement of comprehensive income (loss) for the years ended December 31, 2010 and 2009:

	2010				2009			
	Operating Revenues	Interest Expense	Other Income	Other Comprehensive Income (Loss)	Operating Revenues	Interest Expense	Other Income	Other Comprehensive Income (Loss)
	(In millions)							
Production-related derivatives[1]	$ 390	$	$	$ 11	$ 687	$	$	$ (406)
Other natural gas and power derivatives not designated as hedges	(45)				41			
Total interest rate derivatives[2]		18		(52)		14	(26)	9
Total[3]	$ 345	$ 18	$	$ (41)	$ 728	$ 14	$ (26)	$ (397)

(1) We reclassified $11 million of accumulated other comprehensive loss and $406 million of accumulated other comprehensive income for the years ended December 31, 2010 and 2009 into operating revenues related to derivatives for which we removed the cash-flow hedging designation in 2008. Approximately $11 million of our accumulated other comprehensive loss will be reclassified to operating revenues over the next twelve months.

(2) Included in interest expense is $7 million representing the amount of accumulated other comprehensive income that was reclassified into income related to these interest rate derivatives designated as cash flow hedges for each of the years ended December 31, 2010 and 2009. Also included in interest expense is $11 million and $7 million related to our fair value interest rate derivatives for the years ended December 31, 2010 and 2009. We anticipate that $24 million of our accumulated other comprehensive income will be reclassified to interest expense during the next twelve months. No ineffectiveness was recognized on our interest rate hedges for the year ended December 31, 2010 and 2009.

(3) Excludes approximately $3 million of losses and $21 million of gains for the year ended December 31, 2010 and 2009 recognized in operating expenses related to other derivative instruments not associated with our price risk management activities.

Table of Contents

Credit Risk. We are subject to the risk of loss on our financial instruments that we would incur as a result of non-performance by counterparties or by their failure to post the required collateral pursuant to the terms of their contractual obligations. These exposures are offset where we have a legally enforceable right of setoff. We maintain credit policies with regard to our counterparties to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties financial condition (including credit rating), (ii) obtaining 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. If one of these 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/or quantities cannot be established.

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. Under our margining collateral provisions, we may terminate a contract and liquidate all positions if the counterparty is unable to provide the required collateral, but we are required to return collateral if the amount of posted collateral exceeds the amount of collateral required. Collateral received or returned can vary significantly from day to day based on the changes in the market values and our counterparty s credit ratings. Furthermore, the amount of collateral we hold may be more or less than the fair value of our derivative contracts with that counterparty at any given period.

The following table presents a summary of our exposure from 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, 2010 and 2009:

Counterparty	Investment Grade(1)	Below Investment Grade(1)	Not Rated(1)	Total
		(In millions)		
December 31, 2010				
Financial institutions	$ 331	$	$	$ 331
Natural gas and electric utilities			35	35
Midstream companies		6		6
Net financial instrument assets	331	6	35	372
Collateral held by us(2)			(23)	(23)
Net exposure from derivative assets	$ 331	$ 6	$ 12	$ 349
December 31, 2009				
Energy marketers	$ 21	$ 106	$	$ 127
Natural gas and electric utilities		37	21	58
Financial institutions	156			156
Net financial instrument assets	177	143	21	341
Collateral held by us(2)		(123)	(21)	(144)
Net exposure from derivative assets	$ 177	$ 20	$	$ 197

(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 Investor Service 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.

(2) Consists primarily of non-cash collateral such as letters of credit.

As of December 31, 2010, we have approximately 48 counterparties to our derivative contracts. Based on our assessment of counterparty risk in light of the collateral our counterparties have posted with us, we have determined that our exposure is primarily related to our production-related derivatives and is limited to ten financial institutions, each of which has a current Standard & Poor s credit rating of A or better. Additionally, as of December 31, 2010, three counterparties, Morgan Stanley Capital Group, RRI Energy Services, and Citibank comprise 26 percent, 23 percent and 20 percent, respectively, of our net financial instrument exposure. As of December 31, 2009, three counterparties, Williams Gas Marketing, Citibank, and RRI Energy Services, comprised 31 percent, 13 percent and 11 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.

Table of Contents

As part of our assessment of fair value of our financial liabilities, we also assess our own credit risk after considering collateral posted related to these positions. On January 1, 2009, we adopted an accounting standards update regarding how companies should consider their own credit in determining the fair value of their liabilities that have third-party credit enhancements related to them and recorded a $34 million gain (net of $18 million of taxes), or $0.05 per share, as a result of adopting this new accounting update.

8. 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 (see Note 9). These balances are recoverable or reimbursable over various periods. Below are the details of our regulatory assets and liabilities as of December 31:

	2010	2009
	(In millions)	
Current regulatory assets		
Difference between gas retained and gas consumed in operations	$ 26	$ 14
Other	10	11
Total current regulatory assets	36	25
Non-current regulatory assets		
Taxes on capitalized funds used during construction	254	170
Postretirement benefits	9	13
Unamortized net loss on reacquired debt	63	62
Other	23	25
Total non-current regulatory assets	349	270
Total regulatory assets	$ 385	$ 295
Current regulatory liabilities		
Difference between gas retained and gas consumed in operations	$ 13	$ 22
Environmental liability	78	28
Other	5	12
Total current regulatory liabilities	96	62
Non-current regulatory liabilities		
Environmental liability	44	112
Property and plant depreciation	45	51
Postretirement benefits	71	59
Other	17	14
Total non-current regulatory liabilities	177	236
Total regulatory liabilities	$ 273	$ 298

The significant regulatory assets and liabilities include:

Difference between gas retained and gas consumed in operations: These amounts reflect the value of the volumetric difference between the gas retained and consumed in our operations. These amounts are not included in the rate base but, given our tariffs, are expected to be recovered from our customers or returned to our customers in subsequent fuel filing periods.

Taxes on capitalized funds used during construction: Regulatory asset balance established to offset the deferred tax for the equity component of the allowance for funds used during the construction of long-lived assets. Taxes on capitalized funds used during construction and the offsetting deferred income taxes are included in the rate base and are recovered over the depreciable lives of the long lived asset to which they relate.

Postretirement benefits: Represents unrecognized gains and losses or changes in actuarial assumptions related to our postretirement benefit plans and differences in the postretirement benefit related amounts expensed and the amounts recovered in rates. Postretirement benefit amounts have been included in the rate base computations for certain of our pipelines and are recoverable in such periods as benefits are funded.

Unamortized net loss on reacquired debt: Amount represents the deferred and unamortized portion of losses on reacquired debt which are recovered over the original life of the debt issue through the cost of service.

Environmental liability: Includes amounts collected, substantially in excess of certain polychlorinated biphenyl (PCB) environmental remediation costs to date, through a surcharge to TGP s customers under a settlement approved by the FERC in November of 1995. At this time the environmental liability is not deducted from the rate base on which TGP is allowed to earn current return.

Property and plant depreciation: Amounts represent the deferral of customer-funded amounts for costs of future asset retirements.

Table of Contents

9. Other Assets and Liabilities

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

	2010	2009
	(In millions)	
Other current assets		
Prepaid expenses	$ 54	$ 71
Regulatory assets (Note 8)	36	25
Other	16	30
Total	$ 106	$ 126
Other non-current assets		
Regulatory assets (Note 8)	$ 349	$ 270
Unamortized debt expenses	161	123
Pension and other postretirement benefits (Note 13)	106	88
Notes receivable from affiliates	101	78
Long-term receivables	89	90
Other	106	112
Total	$ 912	$ 761

	2010	2009
	(In millions)	
Other current liabilities		
Accrued taxes, other than income	$ 144	$ 114
Environmental, legal and rate reserves (Note 12)	106	193
Regulatory liabilities (Note 8)	96	62
Pension and other postretirement benefits (Note 13)	44	44
Income taxes	30	19
Deposits	37	32
Dividends payable	16	16
Other	157	204
Total	$ 630	$ 684
Other non-current liabilities		
Pension and other postretirement benefits (Note 13)	$ 626	$ 597
Regulatory liabilities (Note 8)	177	236
Environmental and legal reserves (Note 12)	133	138
Asset retirement obligations (Note 10)	125	133
Insurance reserves	68	75
Other	332	312
Total	$ 1,461	$ 1,491

10. Property, Plant and Equipment

Depreciable lives. The table below presents the depreciation methods 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	15-40
Gathering and processing systems	Straight-line	10-22
Transportation equipment	Straight-line	5-15
Buildings and improvements	Straight-line	7-50
Office and miscellaneous equipment	Straight-line	3-15

(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 file with the FERC for an increase or decrease in our 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.

Excess purchase costs. As of December 31, 2010 and 2009, 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 at December 31, 2010 and 2009. 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, 2010, 2009, and 2008 was approximately $42 million.

Capitalized costs during construction. We capitalize a carrying cost on funds related to the construction of long-lived assets and reflect these amounts as increases in the cost of the asset on our balance sheet. We capitalize an allowance for funds used during construction (AFUDC), that consists of (i) an interest cost on our debt that could be attributed to the assets being constructed, and (ii) for our regulated pipelines, a return on our equity that could be attributed to the assets being constructed. The equity portion is calculated using the most recent FERC approved equity rate of return. Interest costs capitalized are included as a reduction of interest expense in our income statements and were $60 million, $48 million and $45 million during the years ended December 31, 2010, 2009 and 2008. Equity amounts capitalized (exclusive of taxes) in our FERC regulated business are included as other non-operating income on our income statement and were $156 million, $61 million and $37 million during the years ended December 31, 2010, 2009 and 2008. These amounts are recovered over the depreciable lives of the long-lived assets to which they relate and are non-cash investing activities.

Construction work-in progress. At December 31, 2010 and 2009, we had approximately $4.8 billion and $3.6 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. In our exploration and 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 if they are ever demolished or replaced. We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record.

122

Table of Contents

Where we can reasonably estimate the asset retirement obligation, we accrue a liability based on an estimate of the timing and amount of settlement. In estimating 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 5 to 12 percent based on when the liabilities were recorded. We record changes in these estimates based on changes in the expected amount and timing of payments to settle our obligations. Typically, these changes result from obtaining new information about the timing of our obligations to plug and abandon 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). 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 for the substantial majority of our natural gas pipeline and storage system assets because these assets have indeterminate lives.

The net asset retirement obligation 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:

	2010	2009
	(In millions)	
Net asset retirement obligation at January 1	$ 291	$ 254
Liabilities settled	(84)	(72)
Accretion expense	20	21
Liabilities incurred	11	16
Changes in estimate[1]	(51)	72
Net asset retirement obligation at December 31	$ 187	$ 291

(1) Reflects updated information received on our hurricane related asset retirement obligations.

Table of Contents

11. Debt, Other Financing Obligations and Other Credit Facilities

	Year Ended December 31, 2010	2009
	(In millions)	
Short-term financing obligations, including current maturities	$ 489	$ 477
Long-term financing obligations	13,517	13,391
Total	$ 14,006	$ 13,868

The following provides additional detail on our financing obligations:

	Year Ended December 31, 2010	2009
	(In millions)	
CIG		
Notes and debentures, 5.95% through 6.85%, due 2015 through 2037	$ 475	$ 475
El Paso Corporation		
Notes, 6.50% through 12.00%, due 2011 through 2037	5,469	6,362
$1.5 billion revolver, variable due 2012	225	425
EPNG		
Notes, 5.95% through 8.625%, due 2017 through 2032	1,115	1,169
El Paso Exploration & Production Company (EPEP)		
Senior note, 7.75%, due 2013	1	1
Revolving credit facility, variable due 2012	300	834
El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC)		
Revolving credit facility, variable due 2012	270	520
Notes, 4.10% through 8.00%, due 2011 through 2040	1,425	140
Notes, variable due 2012	35	35
SNG		
Notes, 5.90% through 8.00%, due 2017 through 2032	911	911
TGP		
Notes, 6.00% through 8.375%, due 2011 through 2037	1,876	1,876
Other	222	237
	12,324	12,985
Other financing obligations		
Capital Trust I, due 2028	325	325
Ruby Pipeline Holding Company[1]		217
Ruby Pipeline, L.L.C. credit facility	1,094	
Other	320	455
Subtotal	14,063	13,982
Less:		
Other, including unamortized discounts and premiums	57	114
Current maturities	489	477

Total long-term financing obligations, less current maturities	$ 13,517	$ 13,391

(1) This amount was converted to Ruby convertible preferred equity interest in August 2010. For further information, see Note 17.

Table of Contents

Changes in Financing Obligations. During 2010, we had the following changes in our long-term financing obligations (in millions):

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Ruby Holding Company[1]	13.00%	$ 188	$ 187
Ruby Pipeline, L.L.C. credit facility	variable	1,094	1,037
El Paso notes due 2020[2]	6.50%	349	(4)
EPPOC notes due 2015-2040	4.10% - 7.50%	1,283	1,268
EPEP revolving credit facility	variable	500	500
El Paso revolving credit facility	variable	193	193
EPPOC revolving credit facility	variable	160	160
Other	variable	19	19
Increases through December 31, 2010		$ 3,786	$ 3,360
Repayments, repurchases, and other			
EPEP revolving credit facility	variable	$ (1,034)	$ (1,034)
El Paso revolving credit facility	variable	(393)	(393)
EPPOC revolving credit facility	variable	(410)	(410)
El Paso notes due 2010	7.75% - 10.75%	(182)	(182)
El Paso notes due 2013[2]	12.00%	(324)	(77)
El Paso notes due 2011 through 2016[2]	7.00% - 12.00%	(693)	(800)
Elba Express Company L.L.C. credit facility	variable	(157)	(157)
Ruby Holding Company[1]	13.00%	(405)	
Other	various	(50)	(74)
Decreases through December 31, 2010		$ (3,648)	$ (3,127)

(1) Initial interest rate of 7.00% increased to 13.00% effective April 1, 2010. This amount was converted to Ruby convertible preferred equity interest in August 2010.

(2) See *Loss on Debt Extinguishment* below.

Loss on Debt Extinguishment. In 2010, we exchanged approximately $349 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020. In conjunction with the transaction, we paid $77 million of cash premiums, and recorded a loss on debt extinguishment of $105 million.

In December 2010, we repurchased approximately $709 million of our Senior Notes. In conjunction with the transaction, we paid $91 million of cash premiums, and recorded a loss on debt extinguishment of $112 million.

Debt Maturities. Aggregate maturities of the principal amounts of long-term financing obligations as of December 31, 2010 for the next 5 years and in total thereafter are as follows (in millions):

2011	$ 489
2012	1,281
2013	280

2014	534
2015	941
Thereafter	10,538
Total long-term financing obligations, including current maturities	$ 14,063

Credit Facilities/Letters of Credit

We have various credit facilities in place which allow us to borrow funds or issue letters of credit or surety bonds. We enter into letters of credit and issue surety bonds in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of December 31, 2010, we had total debt outstanding of $0.8 billion and approximately $1.1 billion outstanding in letters of credit and surety bonds issued under all of these facilities including approximately $0.5 billion related to our price risk management activities. Listed below is a further description of our credit facilities including remaining capacity under the facilities as of December 31, 2010:

Credit Facility/ Agreement	Maturity Date	Interest Rate	Commitment/ Facility Fees	Remaining Capacity December 31, 2010
$1.5 Billion Revolver	November 2012	LIBOR + 1.25% 1.375% for LCs(1)	0.25% commitment fee on unused capacity(1)	$0.9 billion
$500 Million Unsecured Facility	July 2011	LIBOR or base rate	2.34% fixed facility fee	$0.3 billion
$450 Million Unsecured Facility	December 2013 September 2014	N/A	6.25% (weighted average) facility fee	$0.03 billion
EPEP $1.0 Billion Revolver	September 2012	LIBOR + 1.00% (2)	0.25% unused capacity fee (2)	$0.7 billion
EPEP $300 Million Revolver	December 2011	LIBOR + 2.75%	0.50% facility fee	$0.3 billion
EPPOC $750 Million Unsecured Revolver (3)	November 2012	LIBOR + 0.575% (4)	0.125% commitment fee(4) 0.05% utilization fee(4)	$0.4 billion

(1) Based on our December 31, 2010 credit rating. 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.

(2) Based on December 31, 2010 borrowing levels.

(3) This facility is only available to EPB and its subsidiaries and borrowings are guaranteed by EPB and its subsidiaries. Amounts borrowed are non-recourse to El Paso. Borrowing capacity is expandable to $1.25 billion for certain expansion projects and acquisitions.

(4) Interest rate based on EPB s December 31, 2010 credit rating. The credit facility has two pricing grids, one based on credit ratings and the other based on leverage.

Restrictive Covenants and Collateral Provisions

$1.5 Billion Revolving Credit Agreement. El Paso and certain of its subsidiaries have guaranteed this facility, which is collateralized by our stock ownership in EPNG and TGP who are also eligible borrowers. 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 provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries. Under our credit agreement the most restrictive debt covenants and cross default provisions are:

(a) Our ratio of Debt to Consolidated earnings before interest, income taxes, depreciation and amortization (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 2.0 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 after the expiration of any applicable grace period, with respect to debt in an aggregate principal amount of $200 million or more.

Table of Contents

EPEP $1.0 Billion and $300 Million Revolving Credit Agreements. These facilities are collateralized by certain of our natural gas and oil properties. Our $1.0 billion credit agreement is subject to revaluation on a semi-annual basis. In November 2010, our existing borrowing base was approved by the banks and as of December 31, 2010, the most recent determination was sufficient to fully support this facility. EPEP s borrowings under these facilities are also subject to other 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.

EPPOC $750 Million Revolving Credit Facility. This facility requires that EPB maintain a consolidated leverage ratio, (consolidated indebtedness to consolidated EBITDA (as defined in the credit facility)), of less than 5.0 to 1.0 for any four consecutive quarter periods; and 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified acquisitions. Borrowings under this facility are restricted for use by EPB and its subsidiaries.

Other Restrictions and Provisions. In addition to the above restrictions and provisions, we and/or our subsidiaries are subject to various financial and non-financial covenants and restrictions. These covenants and restrictions 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; limitations on some of our subsidiaries to participate in our cash management program and potential limitations on the ability of some of our subsidiaries to declare and pay dividends. As of December 31, 2010, the restricted net assets of our consolidated subsidiaries were approximately $0.9 billion and are primarily related to restrictions on our ability to receive distributions from Ruby until the project is placed in service. 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 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 provide a full and unconditional guarantee of Trust I s preferred securities.

Trust I s preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75 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 Development L.L.C. (WYCO). In conjunction with the construction of the Totem Gas Storage facility and the High Plains pipeline, our joint venture partner in WYCO, funded 50 percent of the construction costs. We reflected these payments made by our joint venture partner as other non-current liabilities on our balance sheet during construction until project completion when these advances were converted into a financing obligation to WYCO. As of December 31, 2010, the principal amounts of the Totem Gas Storage facility and the High Plains pipeline facility were $75 million and $104 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. Interest payments on these obligations are based on 50 percent of the operating results of the facilities and are currently estimated at a 15.5 percent rate as of December 31, 2010.

Ruby Pipeline Financing. In May 2010, we entered into a seven-year amortizing $1.5 billion credit facility for our Ruby pipeline project that requires principal payments at various dates through June 2017. During 2010, we borrowed approximately $1.1 billion under this credit facility, and in 2011 utilized substantially all of the remaining capacity under this facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance $700 million of the facility by the end of year four. If we do not refinance $700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that begin in July 2011 and convert the floating LIBOR interest rate to fixed interest rates on approximately $1.1 billion of total borrowings under this agreement. For a further discussion of these swaps, see Note 7.

We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, we are required to post letters of credit for any forecasted cost overruns on the project approved by the lender s independent engineer. As of December 31, 2010, we have posted $304 million in letters of credit to cover the anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender s engineer in subsequent months, then additional letters of credit will be required to be issued pursuant to the Ruby financing agreements.

Table of Contents

12. Commitments and Contingencies

Legal Proceedings

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 the Employee Retirement Income Security Act 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. In 2010, a trial court dismissed all of the claims in this matter. The dismissal of the case has been appealed.

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, the trial court ruled that the benefits were vested and not subject to the cap. As a result, we are currently obligated to pay the amounts above the cap. In addition, we are obligated to pay damages incurred by retirees prior to the court s ruling that the benefits were not subject to the cap. In 2008, we recorded $65 million as a reduction to operation and maintenance expense related to the remeasurement of our recorded obligation using actuarial assumptions. We have agreed upon a damage calculation methodology with the plaintiffs and this methodology has been approved by the court. 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. While some of the cases have been settled or dismissed, several of the cases are in various stages of pre-trial or appellate proceedings. We have seven remaining lawsuits, which consist of (i) six cases that are pending in the United States District Court for the District of Nevada, including *J.P. Morgan Trust Company, NA., Liquidating Trustee v. Oneok, Inc., et al.* (filed August 2005), *Breckenridge, et al. v. El Paso Corporation, et al.* (filed May 2006), *Learjet v. El Paso Corporation, et al.* (filed November 2004), *Arandell Corporation, et al. v. El Paso Corporation, et al.* (filed December 2006), *Heartland Regional, et al. v. El Paso Corporation, et al.* (filed April 2007), and *NewPage Wisconsin System, Inc. v. CMS Energy Resource Management Company, et al.* (filed March 2009); and (ii) one case pending state court in Montana, which is *State of Montana v. Williams Energy Marketing, et al.* (filed July 2003, but not served on El Paso). Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, our costs and legal exposure related to the remaining outstanding 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 seeking different remedies against us and many other defendants, 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. Eighty-seven of the cases have been settled or dismissed, with all of the settlements being substantially funded by insurance. We have twelve remaining lawsuits, which consist of (i) ten cases that are pending in the MDL including *City of Fresno v. Chevron USA, et al.* (filed October 2003), *New Jersey Dept. of Environmental Protection v. Atlantic Richfield, et al.* (filed June 2007), *City of Pomona v. Chevron, et al.* (filed December 2008), *Village of Roanoke v. Ashland, et al.* (filed April 2009), *Village of Bethalto v. Ashland, et al.* (filed April 2010), *Town of Kouts v. Ashland, et al.* (filed May 2010), *Coraopolis Water & Sewer Authority v. Ashland, et al.* (filed July 2010), *Bridgewater Water Dept. v. Atlantic Richfield, et al.* (filed September 2010), City of *Kennett v. Ashland, et al.* (filed September 2010), and *City of Pattonsburgh v. Ashland, et al.* (filed October 2010); and (ii) two cases that are pending in state courts, including *State of New Hampshire v. Amerada Hess, et al.* (filed October 2003 in a state court in New

Hampshire) and *Mayor & Council of Berlin, et al. v. Ashland, et al.* (filed April 2010 in a state court in Maryland). Of these remaining lawsuits, it is likely that our insurers will assert denial of coverage on nine of the most-recently filed lawsuits. Although damages in excess of two billion dollars have been alleged in total against all defendants in some of the remaining cases, based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us as well as availability of insurance coverages. Therefore, our costs and legal exposure related to these remaining lawsuits are not currently determinable.

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, 2010, we had approximately $45 million accrued for all of our outstanding legal proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In April 2010, the FERC approved an uncontested partial offer of settlement which increased EPNG s base tariff rates, effective January 1, 2009. As part of the settlement, EPNG made refunds to its customers in 2010. The settlement resolved all but four issues in the proceeding. In January 2011, the Presiding Administrative Law Judge issued a decision that for the most part found against EPNG on the four issues. EPNG will appeal those decisions to the FERC and may also seek review of any of the FERC s decisions to the U.S. Court of Appeals. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate based on the expected final outcome.

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates as permitted under the settlement of the previous rate case. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates, including a proposed change in its rate structure which is expected to increase the percentage of reservation revenues on TGP relative to revenues derived from excess fuel recoveries and throughput on this system. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

CIG Rate Case. Under the terms of its 2006 rate case settlement, CIG must file a new general rate case to be effective no later than October 1, 2011. In late January 2011, CIG filed with FERC an amendment of the 2006 settlement, which is unopposed by all of CIG s shippers, to request a modification of the settlement to allow the effective date of the required new rate case to be moved to December 1, 2011. The purpose of the delay in filing date is to allow CIG and its shippers the opportunity to reach a settlement of the rate proceeding before it is formally filed with the FERC. At this time, the outcome of the pre-filing settlement negotiations and the outcome of the upcoming general rate case, in the event pre-filing settlement cannot be reached, is uncertain.

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 of the disposal or release of specified substances at current and former operating sites. At December 31, 2010, we had accrued approximately $173 million for environmental matters, which has not been reduced by $19 million for amounts to be paid directly under government sponsored programs or through settlement arrangements with third parties. Our accrual includes

approximately $170 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $3 million for related environmental legal costs.

Our estimates of potential liability range from approximately $173 million to approximately $365 million. Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. 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, 2010	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 8	$ 11
Non-operating	151	317
Superfund	14	37
Total	$ 173	$ 365

Superfund Matters. Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as Superfund, or state equivalents for 31 active sites. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

For 2011, we estimate that our total remediation expenditures will be approximately $48 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 $24 million in the aggregate for the years 2011 through 2015, including capital expenditures associated with the impact of the Environmental Protection Agency (EPA) rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

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

Commitments, Purchase Obligations and Other Matters

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space, operating facilities and equipment. The terms of the agreements vary from 2011 until 2053. Future minimum annual rental commitments under our operating leases net of minimum sublease rentals at December 31, 2010, were as follows:

Year Ending December 31,	**Operating Leases (In millions)**

2011	$	13
2012		12
2013		11
2014		11
2015		6
Thereafter		14
Total	$	67

Rental expense was $39 million for each of the years ended December 31, 2010, 2009, and 2008 and is reflected in operation and maintenance expense. Included in rental expense is approximately $21 million in each period associated with right-of-way and other arrangements, principally related to a long-term commitment which extends through 2025.

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, specificity as to duration, and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $0.8 billion, primarily related to indemnification arrangements associated with the sale of ANR Pipeline Company in 2007, 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 11. 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, 2010 and 2009 we recorded obligations of $18 million and $52 million related to our guarantee and indemnification arrangements. Our 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. We have construction contracts and contracts to purchase pipe primarily associated with the Ruby Pipeline project and TGP s 300 Line Project which are anticipated to be placed in service during 2011. Under these agreements we estimate approximately $640 million in obligations for 2011.

Other Commercial Commitments. In 2009, the FERC approved an amendment to the 1995 FERC settlement with TGP that provides for interim refunds over a three year period of approximately $157 million for amounts collected related to certain environmental costs. These refunds are recorded as other current and non-current liabilities on our balance sheet and are expected to be paid over a three year period with interest. As of December 31, 2010, TGP has refunded approximately $58 million to its customers.

We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2010, we had firm commitments under transportation and storage capacity contracts of $783 million due at various times and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of approximately $420 million, the 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. See *Operating Leases* above.

Table of Contents

13. Retirement Benefits

Overview of Retirement Benefit Plans

Pension Plans. 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 their cash balance benefits or their transition benefits under the prior plan formulas. We do not anticipate making any contributions to our cash balance pension plan in 2011.

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 2011.

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 the overall performance of the Company relative to its peers. Amounts expensed under this plan were approximately $39 million, $19 million and $20 million for the years ended December 31, 2010, 2009 and 2008. For 2010, the amount expensed includes an additional discretionary matching contribution.

Other Postretirement Benefit Plans. We provide other postretirement benefits (OPEB), including medical benefits for closed groups of retired employees (such as to certain retirees of Case as further described in Note 12) 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 plans 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. For further information, see Note 8. We expect to contribute $46 million to our other postretirement benefit plans in 2011.

Benefit Obligation, Plan Assets and Funded Status. In accounting for our pension and other postretirement plans, we record an asset or liability based on the over funded or under funded status of each plan. 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 all other operations until those gains and losses are recognized in the income statement.

Other Matters. In various court rulings prior to March 2008, we were required to indemnify Case Corporation (Case) for certain benefits paid to a closed group of Case retirees as further discussed in Note 12. 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 prior to 2008.

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 operation and maintenance expense.

Table of Contents

The table below provides information about our pension and OPEB plans as of and for each of the years ended December 31.

	Pension Benefits		OPEB	
	2010	2009	2010	2009
	(In millions)			
Change in benefit obligation:[1]				
Benefit obligation beginning of period	$ 2,133	$ 1,989	$ 642	$ 673
Service cost	19	19		
Interest cost	115	121	33	38
Participant contributions			6	10
Actuarial (gain) loss	130	159	28	(28)
Benefits paid[2]	(179)	(171)	(50)	(51)
Other		16		
Benefit obligation end of period	$ 2,218	$ 2,133	$ 659	$ 642
Change in plan assets:				
Fair value of plan assets beginning of period	$ 1,979	$ 1,773	$ 243	$ 210
Actual return on plan assets[3]	244	373	22	37
Employer contributions	4	4	49	44
Participant contributions			6	9
Benefits paid	(179)	(171)	(55)	(57)
Fair value of plan assets end of period	$ 2,048	$ 1,979	$ 265	$ 243
Reconciliation of funded status:				
Fair value of plan assets	$ 2,048	$ 1,979	$ 265	$ 243
Less: Benefit obligation	2,218	2,133	659	642
Net liability at December 31	$ (170)	$ (154)	$ (394)	$ (399)

(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 of approximately $5 million and $6 million for each of the years ended December 31, 2010 and 2009 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 it is 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.

Components of Funded Status. The following table details the amounts recognized in our balance sheet at December 31, 2010 and 2009 related to our pension and OPEB plans.

	Pension Benefits		OPEB	
	2010	2009	2010	2009

		(In millions)		
Non-current benefit asset	$	$	$ 106	$ 88
Current benefit liability	(4)	(5)	(40)	(39)
Non-current benefit liability	(166)	(149)	(460)	(448)
Funded status	$ (170)	$ (154)	$ (394)	$ (399)

Components of Accumulated Other Comprehensive Income (Loss). The following table details the amounts recognized in accumulated other comprehensive income (loss), net of income taxes at December 31, 2010 and 2009 related to our pension and OPEB plans.

	Pension Benefits		OPEB	
	2010	2009	2010	2009
	(In millions)			
Unrecognized net gain (loss)	$ (689)	$ (709)	$ 23	$ 43
Unamortized prior service cost	(16)	(16)		
Accumulated other comprehensive income (loss)	$ (705)	$ (725)	$ 23	$ 43

We anticipate that approximately $60 million of our accumulated other comprehensive loss, net of tax, will be recognized as part of our net periodic benefit cost in 2011.

Our accumulated benefit obligation for our defined benefit pension plans was $2.2 billion and $2.1 billion at December 31, 2010 and 2009. Our accumulated benefit obligation for our defined benefit pension plans, whose accumulated benefit obligations exceeded the fair value of plan assets, was $2.2 billion and $2.1 billion as of December 31, 2010 and 2009. The fair value of these plans assets was approximately $2.0 billion at December 31, 2010 and 2009.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $558 million and $542 million as of December 31, 2010 and 2009. The fair value of these plans assets was $58 million and $55 million at December 31, 2010 and 2009.

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 generally the result of economic and capital market conditions. The plans investments include a wide diversification of asset types, fund strategies and fund managers. Although actual allocations vary from time to time from our targeted allocations, the target allocations for our pension plans assets are 50 percent equity securities, 40 percent fixed income securities and 10 percent of other types of investments. The target allocations for our postretirement plans assets are 65 percent equity and 35 percent fixed income securities. Equity securities for our pension plans assets may include investments in large-cap, mid-cap and small-cap companies in the United States, as well as investments in foreign companies. Fixed income securities may include corporate bonds of companies from diversified industries, as well as international fixed income securities, United States Treasuries, and stable income products such as investment contracts. Other types of investments may include hedge funds and real estate investments that follow several different strategies. For our OPEB plans, we may invest plan assets in a manner that replicates, to the extent feasible, the Russell 3000 Index and the Barclays Capital Aggregate Bond Index to achieve equity and fixed income diversification, respectively.

Below are the details of our pension and OPEB plans assets classified by level and a description of their fair values.

Level 1 assets fair values are based on quoted prices in actively traded markets. Included in this level are equity securities, fixed income securities, an exchange traded mutual fund and other securities.

Level 2 assets fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are common collective trust funds, mutual funds and certain fixed income securities. The common collective trust funds and mutual funds fair values are primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date. For common collective trust funds and mutual funds, certain restrictions on redemption exist as of December 31, 2010 where the issuer reserves the right to temporarily delay withdrawal in certain situations such as market conditions or at the issuer s discretion. The fixed income securities fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market.

Table of Contents

Level 3 assets   fair values are similar to Level 2 assets and are also subject to additional restrictions associated with the timing of redemption which extend beyond 90 days as of December 31, 2010. Included in this level is a mutual fund whose fair value is primarily based on the net asset value as reported by the issuer, which is determined based on the fair value of the underlying securities as of the valuation date.

Listed below are the fair values of our pension and OPEB plans   assets that are recorded at fair value classified in each level at December 31, 2010 and 2009 (in millions):

	Pension Assets						
	2010				2009		
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Total
Interest bearing cash	$ 1	$	$	$ 1	$	$	$
Equity securities:							
Domestic companies	582			582	480		480
Foreign companies	107			107	83		83
Fixed income securities:							
U.S. treasuries	66			66	76		76
Corporate bonds	49			49	46		46
Federal mortgage-backed and other	27	4		31	19		19
Common collective trust funds (1)		1,051		1,051		1,223	1,223
Mutual funds(2)		122	39	161		51	51
Other investments					1		1
Total assets at fair value	$ 832	$ 1,177	$ 39	$ 2,048	$ 705	$ 1,274	$ 1,979

(1) For 2010, this category includes common collective trust funds which are invested in approximately 51 percent fixed income, 46 percent equity and other and 3 percent short term securities. For 2009, this category includes common collective trust funds which are invested in approximately 54 percent fixed income, 43 percent equity, and 3 percent short term securities.

(2) For 2010, this category includes mutual funds which are invested in approximately 59 percent hedge funds and approximately 41 percent fixed income. For 2009, this category includes a mutual fund that is substantially invested in fixed income.

	OPEB Assets					
	2010			2009		
	Level 1	Level 2	Total	Level 1	Level 2	Total
Exchange traded mutual fund	$ 12	$	$ 12	$ 12	$	$ 12
Common collective trust funds (1)		253	253		231	231
Total assets at fair value	$ 12	$ 253	$ 265	$ 12	$ 231	$ 243

(1) This category includes common collective trust funds which are invested in approximately 65 percent equity and 35 percent fixed income securities.

The following table presents the changes in our pension plan asset included in Level 3 for the year ended December 31, 2010 (in millions):

	Balance at Beginning of Period	Unrealized gains	Purchases	Balance at End of Period
Mutual fund	$	$ 1	$ 38	$ 39

Expected Payment of Future Benefits. As of December 31, 2010, we expect the following benefit payments under our plans:

Year Ending December 31,	Pension Benefits	OPEB[(1)]
	(In millions)	
2011	$184	$ 56
2012	184	56
2013	185	55
2014	184	55
2015	183	54
2016-2020	890	248

(1) Includes a reduction of approximately $7 million in each of the years 2011-2015 and approximately $33 million in aggregate for 2016-2020 for 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 our benefit obligation as of December 31, 2010, 2009 and 2008 and net benefit costs of our pension and OPEB plans for 2010, 2009 and 2008:

	Pension Benefits			OPEB		
	2010	2009	2008	2010	2009	2008
		(Percent)			(Percent)	
Assumptions related to benefit obligations:						
Discount rate	5.01	5.61	6.33	4.83	5.42	5.98
Rate of compensation increase	4.09	4.20	4.18			
Assumptions related to benefit costs:						
Discount rate	5.61	6.33	6.25	5.42	5.98	6.05
Expected return on plan assets(1)	8.00	8.00	8.00	7.75	8.00	8.00
Rate of compensation increase	4.20	4.18	4.27			

(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.

Actuarial estimates for our OPEB plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 7.4 percent, gradually decreasing to 5.0 percent by the year 2016. Assumed health care cost trends have a significant effect on the amounts reported for OPEB plans. A one-percentage point change in assumed health care cost trends would have the following effects as of December 31, 2010 and 2009:

	2010	2009
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$ 3	$ 3
Accumulated postretirement benefit obligation	49	47
One percentage point decrease:		
Aggregate of service cost and interest cost	$ (2)	$ (3)
Accumulated postretirement benefit obligation	(43)	(42)

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			OPEB		
	2010	2009	2008	2010	2009	2008
			(In millions)			
Service cost	$ 19	$ 19	$ 15	$	$	$
Interest cost	115	121	120	33	38	38
Expected return on plan assets	(157)	(172)	(187)	(13)	(12)	(17)
Amortization of net actuarial loss (gain)	73	45	24	(3)		(5)
Amortization of prior service cost (credit)	1	(1)	(2)		(1)	(1)
Net benefit cost (income)	$ 51	$ 12	$ (30)	$ 17	$ 25	$ 15

Components of Other Comprehensive Income (Loss). The following table details the amounts recognized in our other comprehensive loss, net of income taxes, for the years ended December 31, 2010, 2009, and 2008 related to our pension and OPEB plans.

	Pension Benefits			OPEB		
	2010	2009	2008	2010	2009	2008
			(In millions)			
Prior service cost	$	$ (10)	$ (11)	$	$	$
Net gain (loss)	(28)	27	(509)	(18)	19	(7)
Amortization of net actuarial loss (gain)	47	29	20	(2)		(1)
Amortization of prior service cost (credit)	1	(1)	(2)		(1)	(1)
Other comprehensive income (loss)	$ 20	$ 45	$ (502)	$ (20)	$ 18	$ (9)

14. Equity and Preferred Stock of Subsidiaries

Convertible Perpetual Preferred Stock. We have $750 million of convertible perpetual preferred stock outstanding. Dividends on the preferred stock are declared and approved quarterly and accumulate if not paid. Each share of the preferred stock is convertible at the holder s option, at any time, subject to adjustment, into 77.2295 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of $12.95 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.

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

	Common Stock ($0.01/Share)	**Convertible Preferred Stock (4.99%/Year)**
Amount paid in 2010	$ 28	$ 37
Amount paid in January 2011	$ 7	$ 9
Declared in 2011:		
Date of declaration	February 8, 2011	February 8, 2011
Payable to shareholders on record	March 4, 2011	March 15, 2011
Date payable	April 1, 2011	April 1, 2011

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 2010 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock 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. 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 (Loss). The following table provides the components of our accumulated other comprehensive income (loss) as of December 31 (in millions):

	2010	**2009**
Cash flow hedges	$ (69)	$ (36)
Pension and other postretirement benefits (see Note 13)	(682)	(682)
Total accumulated other comprehensive loss, net of income taxes	$ (751)	$ (718)

Noncontrolling Interests. We are the general partner of EPB, a master limited partnership (MLP), formed in 2007. As of December 31, 2010, we hold a 2 percent general partner interest and a 49 percent limited partner interest (comprised of both common and subordinated units) in the partnership. During the years ended December 31, 2010, 2009, and 2008 we issued noncontrolling interests, net of issuance costs, of $1.3 billion, $212 million, and $15 million in conjunction with the contribution to EPB of additional ownership interests in CIG and SNG and 100 percent ownership interests in Southern LNG Company, L.L.C. (SLNG), which owns the Elba Island LNG receiving terminal, and El Paso Elba Express Company, L.L.C. (Elba Express), which owns the Elba Express Pipeline. To the extent that the consideration paid for by EPB to us for the sales of pipeline assets to EPB is not in the form of additional equity in EPB, then our interest in our pipeline assets will become diluted over time.

In accordance with its partnership agreement, EPB is obligated to make quarterly distributions of available cash to its unitholders. We receive our share of these cash distributions through our limited partner ownership interest, general partner interest, and incentive distribution rights (IDR s) we are entitled to as the general partner. Prior to February 15, 2011, we held subordinated units in EPB. Upon payment of the quarterly cash distribution for the fourth quarter of 2010, the financial tests required for the conversion of subordinated units into common units were satisfied. As a result, our subordinated units were converted on February 15, 2011 into common units on a one-for-one basis effective January 3, 2011.

Our incentive distribution rights pay an increasing percentage interest in quarterly distributions of cash based on the level of distribution to all unitholders. As the holder of these rights we can elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments would be set. We are currently entitled to receive the maximum level of IDRs.

For additional information regarding our master limited partnership, see *net income attributable to noncontrolling interests* in the table below and Note 11.

Preferred Stock of Subsidiaries. During 2009, Global Infrastructure Partners (GIP), our partner on our Ruby pipeline project, contributed $145 million to our subsidiary, Ruby Pipeline Holding Company, L.L.C. (Ruby) and received a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains Investment Company, L.L.C. (Cheyenne Plains). GIP earns a 15 percent dividend on its preferred interests in Cheyenne Plains. In addition, GIP provided a $405 million loan for Ruby project funding. During 2010, GIP s loan of $405 million was converted to a convertible preferred equity interest in Ruby. In addition, GIP provided an additional $120 million contribution for a convertible preferred equity interest in Ruby. GIP will earn a 13 percent return on its convertible preferred interests in Ruby beginning on the earlier of the date the pipeline project is placed in service or August 2011. For a further discussion of the Ruby transaction, see Note 17.

The convertible preferred equity interests in Cheyenne Plains and Ruby have been classified between liabilities and equity on our balance sheet since the events that require redemption of the preferred interests are not entirely within our control and are not certain to occur. We paid preferred dividends of $21 million on GIP s preferred interest in Cheyenne Plains for the year ended December 31, 2010. Also, for the year ended December 31, 2010, we recognized a return of $27 million on GIP s preferred interest in Ruby. Both the preferred dividends and the return on GIP s preferred interests are reflected in net income attributable to noncontrolling interests on our income statement.

The components of net income attributable to noncontrolling interests on our statements of income for the year ended December 31, are as follows (in millions):

	2010	2009	2008
EPB	$ 118	$ 60	$ 34
Preferred Stock of Cheyenne Plains	21	5	
Preferred Stock of Ruby	27		
Net income attributable to noncontrolling interests	$ 166	$ 65	$ 34

15. 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 62 million shares of our common stock under our current plans, which includes 54.5 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, 2010, approximately 23.5 million shares remain available for grant under our current plans, which includes approximately 19.8 million shares under our Omnibus plan, 1.6 million shares under our non-employee director plan and 2.1 million shares under our employee stock purchase plan. We also have approximately 10 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.

Non-Qualified Stock Options. We grant non-qualified stock options to our employees at 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 have vested 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, 2010 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, 2009	29,004,240	$21.87		
Granted	6,625,718	$11.09		
Exercised	(1,069,337)	$ 7.86		
Forfeited or canceled	(995,351)	$ 9.68		
Expired	(1,336,869)	$43.92		
Outstanding at December 31, 2010	32,228,401	$19.58	5.78	$ 89
Vested at December 31, 2010 or expected to vest in the future	31,616,912	$19.77	5.72	$ 87
Exercisable at December 31, 2010	19,998,624	$25.46	4.01	$ 39

During 2010, 2009 and 2008, we recognized approximately $24 million, $23 million and $21 million of pre-tax compensation expense on stock options, capitalized approximately $4 million, $5 million, and $4 million of this expense as part of fixed assets and recorded $8 million, $8 million and $7 million of income tax benefits, respectively. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2010 was approximately $19 million, which is expected to be recognized over a weighted average period of 10 months. Options exercised during the years ended December 31, 2010, 2009 and 2008 had a total intrinsic value of $5 million, less than $1 million and $10 million, generated $8 million, $1 million and $11 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, 2010, 2009 and 2008 the weighted average grant date fair value per share of options granted was $4.55, $2.96 and $5.73.

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

	2010	2009	2008
Expected Term in Years	6.0	6.0	6.0
Expected Volatility	40%	54%	35%
Expected Dividends	0.5%	1.5%	1.0%
Risk-Free Interest Rate	2.9%	2.0%	2.8%

We estimate expected volatility based on an analysis of implied volatilities from traded options on our common stock and from our historical stock price volatility over the expected term, adjusted for certain time periods that we believe are not representative of future stock performance. We estimate the expected term of our option awards based on the vesting period and average remaining contractual term, referred to as the simplified method . We use this method to provide a reasonable basis for estimating our expected term based on insufficient historical data prior to 2006 primarily due to significant changes in the composition of our employees receiving stock-based compensation awards.

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 have vested 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, 2009	4,943,319	$ 10.08
Granted	2,836,570	$ 11.09
Vested	(2,381,583)	$ 11.51
Forfeited	(379,374)	$ 9.56
Nonvested at December 31, 2010	5,018,932	$ 10.01

The weighted average grant date fair value per share for restricted stock granted during 2010, 2009 and 2008 was $11.09, $6.53 and $15.46. The total fair value of shares vested during 2010, 2009 and 2008 was $27 million, $13 million and $29 million.

During 2010, 2009 and 2008, we recognized approximately $25 million, $26 million and $29 million of pre-tax compensation expense on our restricted share awards, capitalized approximately $4 million, $7 million and $7 million of this expense as part of fixed assets and recorded $9 million, $9 million and $10 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at December 31, 2010 was approximately $19 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 current stock compensation accounting standards. Shares issued under this plan were insignificant during 2010, 2009 and 2008.

16. Business Segment Information

As of December 31, 2010, our business consists of two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. 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. Prior to 2010, we also had a Power segment which has been combined into our corporate and other activities for all periods presented. A further discussion of each segment and our corporate and other activities follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. As of December 31, 2010, we conducted our activities primarily through eight wholly or majority owned interstate pipeline systems and equity interests in two transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in three underground natural gas storage facilities and two LNG terminalling facilities, one of which is under construction.

Exploration and Production. 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.

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

Corporate and Other. Our corporate and other activities include our general and administrative functions, our emerging midstream business, our remaining power operations, and other miscellaneous businesses.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2010, 2009 and 2008.

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 and so that our investors may evaluate our operating results without regard to our financing methods or capital structure. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense, (ii) income taxes, and (iii) net income attributable to noncontrolling interests. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income (loss), income (loss) before income taxes and other performance measures such as operating income or operating cash flows. Below is a reconciliation of our EBIT to our net income (loss) for the periods ended December 31:

	2010	2009	2008
		(In millions)	
EBIT	$ 2,175	$ 70	$ (154)
Interest and debt expense	(1,031)	(1,008)	(914)
Income tax benefit (expense)	(386)	399	245
Net income (loss) attributable to El Paso Corporation	758	(539)	(823)
Net income attributable to non-controlling interests	166	65	34
Net income (loss)	$ 924	$ (474)	$ (789)

Table of Contents

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, 2010				
		Segment			
	Pipelines	Exploration and Production	Marketing	Corporate and Other[(1)]	Total
			(In millions)		
Revenue from external customers					
Domestic	$ 2,768	$ 957(2)	$ 597	$ 62	$ 4,384
Foreign	3	86	143		232
Intersegment revenue	49	746(2)	(789)	(6)	
Operation and maintenance	785	384	2	64	1,235
Ceiling test charges		25			25
(Gain) loss on long-lived assets[(3)]	30			(113)	(83)
Depreciation, depletion and amortization	440	477		25	942
Loss on debt extinguishment				(217)	(217)
Earnings (losses) from unconsolidated affiliates	178(4)	(7)		17	188
EBIT	1,572	727	(50)	(74)	2,175
Assets					
Domestic	19,642	4,243	200	532	24,617
Foreign[(5)]	9	414	22	208	653
Investments in unconsolidated affiliates	1,127	399		147	1,673
Capital expenditures and investments in and advances to unconsolidated affiliates, net[(6)]	2,547	1,380		79	4,006

(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 $24 million and an operation and maintenance expense elimination of $1 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $390 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Includes a $110 million gain in Corporate and Other related to our sale of midstream assets into our newly formed joint venture and $21 million non-cash asset write down in Pipelines based on a FERC order related to the sale of a compressor station and gas processing plant in 2009.

(4) Includes a gain of approximately $80 million related to the sale of our interests in certain Mexican pipeline and compression assets.

(5) Of total foreign assets, approximately $0.4 billion relates to property, plant and equipment, and approximately $0.1 billion relates to investments in and advances to unconsolidated affiliates.

(6) Amounts are net of third party reimbursements of our capital expenditures, returns of capital and sales of investments and advances.

	As of or for the Year Ended December 31, 2009				
	Segment				
	Pipelines	Exploration and Production	Marketing	Corporate and Other[1]	Total
			(In millions)		
Revenue from external customers					
Domestic	$ 2,711	$ 1,257(2)	$ 497	$ 17	$ 4,482
Foreign	10	26	114		150
Intersegment revenue	46	545(2)	(582)	(10)	(1)
Operation and maintenance	807	392	8	28	1,235
Ceiling test charges		2,123			2,123
(Gain) loss on long-lived assets	(2)	25		(1)	22
Depreciation, depletion and amortization	414	440		13	867
Earnings (losses) from unconsolidated affiliates	92	(30)		5	67
EBIT	1,416	(1,349)	20	(17)	70
Assets					
Domestic	17,090	3,574	321	580	21,565
Foreign[3]	234	451	24	231	940
Investments in unconsolidated affiliates	1,133	456		129	1,718
Capital expenditures and investments in and advances to unconsolidated affiliates, net[4]	1,710	1,154		(110)	2,754

(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 $10 million.

(2) Revenues from external customers include gains of $687 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Of total foreign assets, approximately $0.4 billion relates to property, plant and equipment and approximately $0.3 billion relates to investments in and advances to unconsolidated affiliates.

(4) Amounts are net of third party reimbursements of our capital expenditures, returns of capital and sales of investments and advances.

	As of or for the Year Ended December 31, 2008				
	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate[1] and Other	Total
			(In millions)		
Revenue from external customers					
Domestic	$ 2,621	$ 1,317(2)	$ 1,137	$ 9	$ 5,084
Foreign	11	22	237	9	279
Intersegment revenue	52	1,423(2)	(1,457)	(18)	
Operation and maintenance	824	404	19	(61)	1,186
Ceiling test charges		2,669			2,669
(Gain) loss on long-lived assets	39			(35)	4
Depreciation, depletion and amortization	395	799		11	1,205
Earnings (losses) from unconsolidated affiliates	97	(93)		44	48
EBIT	1,273	(1,448)	(104)	125	(154)
Assets					
Domestic	14,917	5,821	444	1,494	22,676
Foreign[3]	204	321	21	446	992
Investments in unconsolidated affiliates	1,054	531		118	1,703
Capital expenditures, and investments in and advances to unconsolidated affiliates, net[4]	1,457	1,622		27	3,106

(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 of $196 million related to our financial derivative contracts associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing 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, returns of capital and sales of investments and advances.

Table of Contents

17. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby. We consolidate our investment in Ruby, a variable interest entity that owns our Ruby pipeline project, as its primary beneficiary. In July 2009, we entered into an agreement with GIP whereby they agreed to invest up to $700 million and acquire a 50 percent equity interest in Ruby subject to certain conditions. As part of this agreement, GIP (i) contributed $145 million in exchange for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains (a variable interest entity that we also consolidate as its primary beneficiary) and (ii) provided a $405 million loan for Ruby project funding.

In 2010, we entered into a $1.5 billion third party project financing facility, received a BLM right-of-way grant, received final approval from the FERC, and began construction of the Ruby pipeline. Several groups have filed appeals of certain approvals and actions of the BLM and the U.S. Fish and Wildlife Service related to the project. We are currently unable to predict what action, if any, the courts will take in response to these appeals or any subsequent filings that may be made by one or more of these groups.

During 2010, GIP s loan of $405 million was converted to a convertible preferred equity interest in Ruby, GIP provided an additional $120 million contribution for a convertible preferred equity interest in Ruby, and we borrowed approximately $1.1 billion under the $1.5 billion facility.

GIP will hold its interest in Cheyenne Plains until certain conditions are satisfied, including placing the Ruby pipeline project in service. GIP has the right to convert its preferred equity in Ruby to common equity in Ruby at any time; however, the preferred equity is subject to mandatory conversion to Ruby common equity upon the satisfaction of certain conditions, including Ruby entering into certain additional firm transportation agreements.

If all conditions to closing are satisfied or waived, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, if certain conditions are not satisfied including placing the Ruby pipeline project in service by November 2011, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining investments in Cheyenne Plains and Ruby including a 15 percent return on its investments in Cheyenne Plains and Ruby. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and 50 million common units we own in EPB.

For additional information on our Ruby project financing, see Note 11.

Other. We also hold interests in other variable interest entities that we account for as investments in unconsolidated affiliates. These entities do not have significant operations and accordingly do not have a material impact to our financial statements.

Accounts Receivable Sales Program. During 2009, several of our pipeline subsidiaries had agreements to sell senior interests in certain of their accounts receivable (which are short-term assets that generally settle within 60 days) to a third party financial institution (through wholly-owned special purpose entities), and we retained subordinated interests in those receivables. The sale of these senior interests qualified for sale accounting and was conducted to accelerate cash from these receivables, the proceeds from which were used to increase liquidity and lower our overall cost of capital. During the years ended December 31, 2009 and 2008, we received $987 million and $862 million of cash related to the sale of the senior interests, collected $869 million and $977 million from the subordinated interests we retained in the receivables, and recognized a loss of approximately $2 million and $3 million on these transactions. At December 31, 2009, the third party financial institution held $90 million of senior interests and we held $79 million of subordinated interests. Our subordinated interests were reflected in accounts receivable on our balance sheet. In January 2010, we terminated these accounts receivable sales programs and paid $90 million to acquire the senior interests. We reflected the cash flows related to the accounts receivable sold under this program, changes in our retained subordinated interests, and cash paid to terminate the programs, as operating cash flows on our statement of cash flows.

In the first quarter of 2010, we entered into new accounts receivable sales programs to continue to sell accounts receivable to the third party financial institution that qualify for sale accounting under the updated accounting standards related to financial asset transfers, and to include an additional pipeline subsidiary s accounts receivable in the program. Under these programs, several of our pipeline subsidiaries sell receivables in their entirety to the third-party financial institution (through wholly-owned special purpose entities). At December 31, 2010, the third-party financial institution held $210 million of the accounts receivable we sold under the program. In connection with our accounts receivable sales, we receive a portion of the sales proceeds up front and receive an additional amount upon the collection of the underlying receivables (which we refer to as a deferred purchase price). Our ability to recover the deferred purchase price is based solely on the collection of the underlying receivables. During the year ended December 31, 2010, we sold approximately $2.5 billion of accounts receivable to the third-party financial institution, for which we received approximately $1.5 billion of cash up front and had a deferred purchase price of approximately $1.0 billion. We received approximately $967 million of cash related to the deferred purchase price when the underlying receivables were collected during 2010. As of December 31, 2010, we had not collected approximately $89 million of deferred purchase price related to our accounts receivable sales, which is reflected as other accounts receivable on our balance sheet (and was initially recorded at an amount which approximates its fair value as a Level 2 measurement). We recognized a loss of approximately $2 million on our accounts receivable sales during the year ended December 31, 2010. Because the cash received up front and the deferred purchase price relate to the sale or ultimate collection of the underlying receivables, and are not subject to significant other risks given their short term nature, we reflect all cash flows under the new accounts receivable sales programs as operating cash flows on our statement of cash flows.

Under both the prior and current accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the periods ended December 31, 2010, 2009 and 2008.

The third party financial institution involved in both of these accounts receivable sales programs acquires interests in various financial assets and issues commercial paper to fund those acquisitions. We do not consolidate the third party financial institution because we do not have the power to control, direct, or exert significant influence over its overall activities since our receivables do not comprise a significant portion of its operations.

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, gains and losses on divestitures and other adjustments recorded by us. As of December 31, 2010 and 2009, our investment balance exceeded the net equity in the underlying net assets of these investments by $98 million and $269 million due primarily to purchase price adjustments, net of impairment charges, recorded by us. The majority of our purchase price adjustments is related to our investment in Four Star. We amortize and generally 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**		
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2008**
	(Percent)		**(In millions)**		**(In millions)**		
Four Star[1]	49	49	$ 393	$ 450	$ (7)	$ (30)	$ (93)
Citrus	50	50	822	630	92	66	64
Gulf LNG[2]	50	50	266	285	(5)	(2)	
Bolivia to Brazil Pipeline	8	8	104	105	12	(2)	25
Gasoductos de Chihuahua[3]		50		184	88	25	29
Other	various	various	88	64	8	10	23
Total			$ 1,673	$ 1,718	$ 188	$ 67	$ 48

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $38 million for the year ended December 31, 2010, $48 million for the year ended December 31, 2009, and $53 million for the year ended December 31, 2008. In 2008, we recorded a $125 million impairment of the carrying value of our investment based on a decrease in its fair value that resulted from declining commodity prices.

(2) As of December 31, 2010 and 2009, we had outstanding advances and receivables of $83 million and $56 million, not included above, related to our investment in Gulf LNG.

(3) In April 2010, we completed the sale of our interest in this investment and recorded a pretax gain of approximately $80 million. See Note 2.

As of December 31, 2010, approximately $0.6 billion of the equity in undistributed earnings of 50 percent or less owned entities accounted for by the equity method was included in our consolidated accumulated deficit. We received distributions and dividends from our unconsolidated affiliates of $64 million, $90 million and $182 million for the years ended December 31, 2010, 2009 and 2008. Included in these amounts are returns of capital of less than $1 million in 2010 and $2 million in 2009 and 2008. During 2010, we made a capital contribution of $100 million to Citrus, one of our unconsolidated affiliates.

Table of Contents

Below is summarized financial information of our proportionate share of the operating results and financial position of our unconsolidated affiliates.

	Year Ended December 31,		
	2010	2009	2008
		(In millions)	
Operating results data:			
Operating revenues	$ 503	$ 526	$ 708
Operating expenses	269	268	331
Net income	149	130	220
Financial position data:			
Current assets	$ 160	$ 358	$ 320
Non-current assets	3,842	3,060	2,667
Short-term debt	14	232	141
Other current liabilities	192	186	100
Long-term debt	1,655	1,028	858
Other non-current liabilities	566	523	666
Equity in net assets	1,575	1,449	1,222

Our transactions with unconsolidated affiliates were not material in 2010, 2009 and 2008.

Other Investment-Related Matters. We currently have outstanding disputes and other matters related to an investment in two Brazilian power plant facilities (Manaus/Rio Negro) formerly owned by us. We have filed lawsuits to collect amounts due to us (approximately $70 million of Brazilian reais-denominated accounts receivable) by the plant s power purchaser, which are also guaranteed by the purchaser s parent, Eletrobras, Brazil s state-owned utility. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable.

Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately $78 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser must indemnify our project companies for these ICMS taxes, along with related interest and penalties, and has therefore been defending the projects against this lawsuit. In order to prevent further collection efforts by the tax authorities for this matter, security must be provided for the potential tax liability to the court s satisfaction. The tax authorities and court have rejected the assets pledged by the power purchaser to date, and during 2010 the tax courts blocked certain of El Paso s bank accounts associated with the Rio Negro power plant in order to obtain this security. The power purchaser has appealed the court s decision. If the power purchaser is unable to resolve this tax matter, our ability to collect amounts due to us from the power purchaser could be impacted. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser s parent.

The ultimate resolution of the matters discussed above is unknown at this time, and adverse developments related to either our ability to collect amounts due to us or related to these disputes and claims could require us to record additional losses in the future.

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)				
2010					
Operating revenues	$ 1,401	$ 1,018	$ 1,213	$ 984	$ 4,616
Operating income (loss)	760	384	518	381	2,043
Earnings from unconsolidated affiliates	28	111	28	21	188
Net income (loss)	419	186	183	136	924
Net income (loss) attributable to El Paso Corporation	388	157	142	71	758
Net income (loss) attributable to El Paso Corporation s common stockholders	379	147	133	62	721
Basic earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.54	0.21	0.19	0.09	1.03
Diluted earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	0.51	0.21	0.19	0.09	1.00
2009					
Operating revenues	$ 1,484	$ 973	$ 981	$ 1,193	$ 4,631
Operating income (loss)	(1,269)	391	329	498	(51)
Earnings from unconsolidated affiliates	19	12	11	25	67
Net income (loss)	(957)	100	82	301	(474)
Net income (loss) attributable to El Paso Corporation	(969)	89	67	274	(539)
Net income (loss) attributable to El Paso Corporation s common stockholders	(978)	79	58	265	(576)
Basic earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	(1.41)	0.11	0.08	0.38	(0.83)
Diluted earnings per common share					
Net income (loss) attributable to El Paso Corporation s common stockholders	(1.41)	0.11	0.08	0.36	(0.83)

Below are items affecting comparability of amounts reported in the respective quarters of 2010 and 2009:

December 31, 2010. We recorded (i) a $113 million loss on a debt extinguishment, (ii) a $110 million gain on sale of midstream assets into a joint venture and (iii) $78 million of losses related to changes in fair value of our exploration and production financial derivatives.

September 30, 2010. We recorded (i) $184 million of gains related to changes in fair value of our exploration and production financial derivatives and (ii) a $104 million loss on a debt extinguishment.

June 30, 2010. We recorded (i) an $80 million gain on sale of our interests in certain Mexican pipeline and compression assets and (ii) $31 million of gains related to changes in fair value of our exploration and production financial derivatives.

March 31, 2010. We recorded $253 million of gains related to changes in fair value of our exploration and production financial derivatives.

December 31, 2009. We recorded (i) $151 million of gains related to changes in fair value of our exploration and production financial derivatives, (ii) an $88 million tax benefit related to the liquidation of foreign entities, (iii) a $22 million charge related to restructuring costs and (iv) $38 million in international ceiling test charges.

September 30, 2009. We recorded $87 million of gains related to changes in fair value of our exploration and production financial derivatives.

June 30, 2009. We recorded (i) $55 million of gains related to changes in fair value of our exploration and production financial derivatives, (ii) a $25 million mark-to-market gain associated with an indemnification in conjunction with the sale of a legacy ammonia facility, (iii) a $22 million loss on the sale of our Porto Velho notes receivables and (iv) $21 million in mark-to-market gains on power contracts.

March 31, 2009. We recorded (i) a total of $2.1 billion in domestic and international ceiling test charges, (ii) $394 million in mark-to-market gains related to changes in fair value of our exploration and production financial derivatives and (iii) $52 million gain related to the application of accounting standard updates on certain of our derivative liabilities.

Table of Contents

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 (U.S.), 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):

	U.S.	Brazil and Egypt[1]	Worldwide
2010 Consolidated:			
Natural gas and oil properties:			
Costs subject to amortization	$ 19,676	$ 1,091	$ 20,767
Costs not subject to amortization	537	248	785
	20,213	1,339	21,552
Less accumulated depreciation, depletion and amortization	16,993	902	17,895
Net capitalized costs	$ 3,220	$ 437	$ 3,657
2010 Unconsolidated Affiliate Four Star[2]:			
Natural gas and oil properties	$ 614	$	$ 614
Less accumulated depreciation, depletion and amortization	466		466
Net capitalized costs	$ 148	$	$ 148
2009 Consolidated:			
Natural gas and oil properties:			
Costs subject to amortization	$ 19,161	$ 1,055	$ 20,216
Costs not subject to amortization	256	214	470
	19,417	1,269	20,686
Less accumulated depreciation, depletion and amortization	16,921	867	17,788
Net capitalized costs	$ 2,496	$ 402	$ 2,898
2009 Unconsolidated Affiliate Four Star[2]:			
Natural gas and oil properties	$ 594	$	$ 594
Less accumulated depreciation, depletion and amortization	436		436
Net capitalized costs	$ 158	$	$ 158

(1) Capitalized costs for Egypt were $66 million and $70 million as of December 31, 2010 and 2009.

(2) Amounts represent our approximate 49 percent equity interest in the underlying oil and gas assets of Four Star. Four Star applies the successful efforts method of accounting for its oil and gas properties.

Table of Contents

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):

	U.S.	Brazil and Egypt[1]	Worldwide
2010 Consolidated:			
Property acquisition costs			
Proved properties	$ 51	$	$ 51
Unproved properties	269		269
Exploration costs	600	58	658
Development costs	276	28	304
Costs expended	1,196	86	1,282
Asset retirement obligation costs	7		7
Total costs incurred	$ 1,203	$ 86	$ 1,289
2010 Unconsolidated Affiliate Four Star[2]:			
Development costs expended	$ 20	$	$ 20
2009 Consolidated:			
Property acquisition costs			
Proved properties	$ 87	$	$ 87
Unproved properties	89	51	140
Exploration costs	355	67	422
Development costs	324	118	442
Costs expended	855	236	1,091
Asset retirement obligation costs	36	6	42
Total costs incurred	$ 891	$ 242	$ 1,133
2009 Unconsolidated Affiliate Four Star[2]:			
Development costs expended	$ 10	$	$ 10
2008 Consolidated:			
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

(1) Costs incurred for Egypt were $20 million, $81 million and $26 million for the years ended December 31, 2010, 2009 and 2008.

(2) Amounts represent our approximate 49 percent equity interest in the underlying costs incurred by Four Star.

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 $81 million, $80 million and $85 million for the years ended December 31, 2010, 2009 and 2008. We also capitalized interest of $9 million, $7 million and $29 million for the years ended December 31, 2010, 2009 and 2008.

In our December 31, 2010 reserve report, the amounts estimated to be spent in 2011, 2012 and 2013 to develop our consolidated worldwide proved undeveloped reserves are $597 million, $616 million and $512 million.

Unevaluated Capitalized Costs. We exclude capitalized costs of natural gas and oil properties from amortization that are in various stages of evaluation or are part of a major development project. We expect these costs to be included in the amortization calculation in the next three to five 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, 2010 pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2010	Costs Excluded for Years Ended December 31[1] 2010	2009	2008	Cumulative Balance January 1, 2008
U.S.					
Acquisition	$ 407	$ 257	$ 72	$ 43	$ 35
Exploration	130	109	15	5	1
Total U.S.	537	366	87	48	36
Brazil & Egypt					
Acquisition	45	5	35	1	4
Exploration	203	52	22	31	98
Total Brazil & Egypt[2]	248	57	57	32	102
Worldwide	$ 785	$ 423	$ 144	$ 80	$ 138

(1) Includes capitalized interest of $8 million, $5 million and $4 million for the years ended December 31, 2010, 2009 and 2008.

(2) Includes $66 million related to Egypt at December 31, 2010.

Our unevaluated costs in Brazil include approximately $94 million related to our major development project in the Pinauna field. These costs relate to exploratory drilling in 2007 which led to a discovery of hydrocarbons that will be used as fuel in the development of the Pinauna project. We are currently working to obtain environmental permits to develop the project and have experienced delays in obtaining these permits due to a number of factors, including changes in government and additional regulatory inquiries resulting indirectly from the Gulf of Mexico spill in 2010. We currently anticipate we will receive a decision on our preliminary license request during late 2011 allowing us to proceed with development activities. Additionally, we expect to begin including unevaluated Pinauna project costs in the amortizable base in 2014 as the project is evaluated. However, we could experience additional delays of our development activities. Prior to the completion of our evaluation, we expect that our unevaluated Pinauna project costs will continue to be held outside of the amortizable base of the Brazilian full cost pool. All of our unevaluated costs, including those related to the Pinauna project, are assessed periodically for impairment.

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, 2010 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 2009 consolidated proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2010 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), conducted an audit of the estimates of the proved reserves prepared by us as of December 31, 2010. In connection with its audit, Ryder Scott reviewed 86 percent of the properties associated with our proved reserves on a natural gas equivalent basis, representing 88 percent of the total discounted future net cash flows of these proved reserves. Ryder Scott also conducted an audit of the estimates we prepared of the proved reserves of Four Star as of December 31, 2010. In connection with the audit of these proved reserves, Ryder Scott reviewed 86 percent of the properties associated with Four Star s total proved reserves on a natural gas equivalent basis, representing 86 percent of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10 percent of Ryder Scott s estimates. Ryder Scott s report is included as an exhibit to this Annual Report on Form 10-K.

Table of Contents

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	
Consolidated:								
January 1, 2008	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(1)	475		475	16,468		16,468	456	577
Purchases of reserves in place(1)	10		10	1,295		1,295	68	18
Sales of reserves in place(1)	(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
Revisions due to prices	(138)	(2)	(140)	13,336	(380)	12,956	(3,552)	(84)
Revisions other than price	(36)	(6)	(42)	3,477	(640)	2,837	1,511	(16)
Extensions and discoveries(2)	380	70	450	18,089	2,136	20,225	16	572
Purchases of reserves in place(2)	19		19	7,343		7,343		63
Sales of reserves in place(2)	(49)		(49)	(1,328)		(1,328)	(260)	(59)
Production	(215)	(4)	(219)	(3,978)	(100)	(4,078)	(1,570)	(252)
December 31, 2009	2,052	105	2,157	60,849	4,196	65,045	304	2,549
Revisions due to prices	108	3	111	8,719	88	8,807	105	164
Revisions other than price	(58)	(13)	(71)	7,873	(1,246)	6,627	6,977	11
Extensions and discoveries(3)	506		506	28,141		28,141	3,088	693
Purchases of reserves in place(3)	25		25	3,045		3,045		43
Sales of reserves in place(3)	(21)		(21)	(1,024)		(1,024)		(27)
Production	(216)	(10)	(226)	(4,363)	(384)	(4,747)	(1,423)	(263)

December 31, 2010	2,396	85	2,481	103,240	2,654	105,894	9,051	3,170

Table of Contents

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	
Unconsolidated Affiliate Four Star[2]*:*								
January 1, 2009	176		176	2,199		2,199	5,518	222
Revisions due to prices	(9)		(9)	23		23	(40)	(9)
Revisions other than price	10		10	100		100	456	13
Extensions and discoveries	1		1	4		4	8	1
Production	(20)		(20)	(419)		(419)	(678)	(26)
December 31, 2009	158		158	1,907		1,907	5,264	201
Revisions due to prices	8		8	44		44	87	9
Revisions other than price	6		6	36		36	(325)	4
Extensions and discoveries							5	
Production	(17)		(17)	(364)		(364)	(573)	(22)
December 31, 2010	155		155	1,623		1,623	4,458	192
Total Combined:								
December 31, 2009	2,210	105	2,315	62,756	4,196	66,952	5,568	2,750
December 31, 2010	2,551	85	2,636	104,863	2,654	107,517	13,509	3,362
Consolidated:								
Proved developed reserves:								
Beginning of year	1,441	91	1,532	26,588	3,212	29,800	304	1,713
End of year	1,559	75	1,634	38,278	2,403	40,681	6,096	1,914
Proved undeveloped reserves:								
Beginning of year	610	14	624	34,261	984	35,245		836
End of year	837	10	847	64,962	251	65,213	2,955	1,256

155

Table of Contents

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	
Unconsolidated Affiliate Four Star:								
Proved developed reserves:								
Beginning of year	135		135	1,860		1,860	4,295	172
End of year	129		129	1,574		1,574	3,483	159
Proved undeveloped reserves:								
Beginning of year	23		23	47		47	969	29
End of year	26		26	49		49	975	32
Total Combined:								
Proved developed reserves:								
Beginning of year	1,577	91	1,668	28,448	3,212	31,660	4,599	1,885
End of year	1,688	75	1,763	39,852	2,403	42,255	9,579	2,074
Proved undeveloped reserves:								
Beginning of year	633	14	647	34,308	984	35,292	969	865
End of year	863	10	873	65,011	251	65,262	3,930	1,288

(1) 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 2008, we acquired interests in domestic natural gas and oil producing properties located in the Western and Central divisions. We also sold domestic natural gas and oil properties located primarily in the Gulf of Mexico.

(2) In 2009, of the 572 Bcfe of extensions and discoveries, 301 Bcfe related to the Central division, of which, 208 Bcfe related to the Haynesville Shale and 70 Bcfe related to the Holly/Kingston fields. We also had 147 Bcfe of extensions and discoveries related to Altamont in the Western division and 83 Bcfe related to the Camarupim Field in Brazil. In addition, 41 Bcfe of extensions and discoveries related to the Gulf Coast division, of which, 14 Bcfe related to Eugene Island 364/365 in the Gulf of Mexico and 12 Bcfe related to the Wilcox area in South Texas. In 2009, we acquired interests in domestic natural gas and oil producing properties located in the Western division. We also sold domestic natural gas producing properties located in the Central and Western divisions.

(3) In 2010, of the 693 Bcfe of extensions and discoveries, 452 Bcfe related to the Central division, of which, 425 Bcfe related to the Haynesville Shale area. There were 238 Bcfe of extensions and discoveries in the Gulf Coast division with 187 Bcfe of that coming from the Eagle Ford Shale. The Western division accounted for 3 Bcfe of

extensions and discoveries and there were no extensions and discoveries in the International division.

In January 2010, the Financial Accounting Standards Board updated accounting standards on extractive activities for oil and gas to align the oil and gas reserve estimation and disclosures with the requirements in the SEC s final rule on Modernization of Oil and Gas Reserve Reporting, which was effective December 31, 2009. Among other things, the new standard revised the definition of proved reserves and required us to use a 12-month average price to estimate proved reserves rather than a period end spot price as required in prior periods. The 12-month average price is calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The first day 12-month average U.S. price used to estimate our proved reserves at December 31, 2010 was $4.38 per MMBtu for natural gas and $79.43 per barrel of oil.

All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of reasonable certainty be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices, economic conditions and government restrictions. In addition, as a result of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate.

Table of Contents

Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. 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 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 effects of governmental regulation. In addition, due to the 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.

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, 2010, there have been no major discoveries or other events, favorable or otherwise, that may be considered to have caused a significant change in our estimated proved reserves.

Table of Contents

Results of Operations. Results of operations for natural gas and oil producing activities by fiscal year were as follows at December 31 (in millions):

	U.S.	Brazil and Egypt	Worldwide
2010 Consolidated:			
Net Revenues[(1)]			
Sales to external customers	$ 551	$ 86	$ 637
Affiliated sales	743		743
Total	1,294	86	1,380
Cost of products and services[(2)]	(81)	(5)	(86)
Production costs[(3)]	(218)	(46)	(264)
Ceiling test charges[(4)]		(25)	(25)
Depreciation, depletion and amortization	(432)	(28)	(460)
	563	(18)	545
Income tax expense	(204)		(204)
Results of operations from producing activities	$ 359	$ (18)	$ 341
Depreciation, depletion and amortization ($/Mcfe)[(5)]	$ 1.72	$ 2.33	$ 1.75
2010 Unconsolidated Affiliate Four Star[(6)]:			
Net Revenues Sales to external customers[(1)]	$ 119	$	$ 119
Cost of products and services	(4)		(4)
Production costs[(3)]	(36)		(36)
Depreciation, depletion and amortization	(28)		(28)
Asset impairment	(4)		(4)
	47		47
Income tax expense	(17)		(17)
Results of operations from producing activities	$ 30	$	$ 30
Depreciation, depletion and amortization ($/Mcfe)[(7)]	$ 1.24	$	$ 1.24
2009 Consolidated:			
Net Revenues[(1)]			
Sales to external customers	$ 534	$ 25	$ 559
Affiliated sales	538		538
Total	1,072	25	1,097
Cost of products and services[(2)]	(72)	(5)	(77)
Production costs[(3)]	(226)	(26)	(252)

Ceiling test charges[4]	(2,031)	(92)	(2,123)
Depreciation, depletion and amortization	(415)	(9)	(424)
	(1,672)	(107)	(1,779)
Income tax benefit	605		605
Results of operations from producing activities	$ (1,067)	$ (107)	$ (1,174)
Depreciation, depletion and amortization ($/Mcfe)[5]	$ 1.67	$ 2.13	$ 1.68
2009 Unconsolidated Affiliate Four Star[7]*:*			
Net Revenues Sales to external customers[1]	$ 100	$	$ 100
Cost of products and services[2]	(6)		(6)
Production costs[3]	(37)		(37)
Depreciation, depletion and amortization	(29)		(29)
	28		28
Income tax expense	(10)		(10)
Results of operations from producing activities	$ 18	$	$ 18
Depreciation, depletion and amortization ($/Mcfe)[7]	$ 1.09	$	$ 1.09

158

	U.S.	Brazil and Egypt	Worldwide
2008 Consolidated:			
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 expense (benefit) [8]	364		364
Results of operations from producing activities	$ (646)	$ (491)	$ (1,137)
Depreciation, depletion and amortization ($/Mcfe)[5]	$ 2.87	$ 3.62	$ 2.88

(1) Excludes the effects of natural gas and oil derivative contracts.

(2) Cost of products and services consists of transportation costs and divisional general and administrative expenses of $13 million and $11 million in 2010 and 2009 and only transportation costs in 2008.

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

(4) Includes $25 million, $34 million and $9 million related to Egypt for the years ended December 31, 2010, 2009 and 2008.

(5) These amounts represent depreciation, depletion and amortization for unit of production only and include accretion expense on asset retirement obligations of $0.06/Mcfe in 2010 and 2009, respectively, and $0.05/Mcfe in 2008.

(6) Results do not include amortization of $38 million related to cost in excess of our equity interest in the underlying net assets of Four Star.

(7) Includes accretion expense on asset retirement obligations of $0.14/Mcfe in 2010 and $0.13/Mcfe in 2009.

(8) 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.

Table of Contents

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):

	U.S.	Brazil	Worldwide
2010 Consolidated:			
Future cash inflows[1]	$ 17,145	$ 659	$ 17,804
Future production costs	(4,768)	(325)	(5,093)
Future development costs	(3,249)	(67)	(3,316)
Future income tax expenses	(2,403)	(9)	(2,412)
Future net cash flows	6,725	258	6,983
10% annual discount for estimated timing of cash flows	(2,905)	(77)	(2,982)
Standardized measure of discounted future net cash flows	$ 3,820	$ 181	$ 4,001
2010 Unconsolidated Affiliate Four Star[2]:			
Future cash inflows[1]	$ 943	$	$ 943
Future production costs	(404)		(404)
Future development costs	(34)		(34)
Future income tax expenses	(192)		(192)
Future net cash flows	313		313
10% annual discount for estimated timing of cash flows	(131)		(131)
Standardized measure of discounted future net cash flows	$ 182	$	$ 182
2009 Consolidated:			
Future cash inflows[1]	$ 10,058	$ 714	$ 10,772
Future production costs	(3,531)	(339)	(3,870)
Future development costs	(1,698)	(108)	(1,806)
Future income tax expenses	(511)	(17)	(528)
Future net cash flows	4,318	250	4,568
10% annual discount for estimated timing of cash flows	(1,744)	(82)	(1,826)
Standardized measure of discounted future net cash flows	$ 2,574	$ 168	$ 2,742
2009 Unconsolidated Affiliate Four Star[2]:			
Future cash inflows[1]	$ 855	$	$ 855
Future production costs	(394)		(394)
Future development costs	(32)		(32)
Future income tax expenses	(157)		(157)
Future net cash flows	272		272
10% annual discount for estimated timing of cash flows	(110)		(110)

Standardized measure of discounted future net cash flows	$ 162	$	$ 162
2008 Consolidated:			
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
2008 Unconsolidated Affiliate Four Star[2]	$ 396	$	$ 396

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2010, 2009 and 2008. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

(2) Amounts represent our approximate 49 percent equity interest in Four Star.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves as of December 31, 2010 were computed using a first day 12-month average U.S. price of $4.38 per MMBtu for natural gas and $79.43 per barrel of oil. The 12-month average price is calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period.

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]		
	2010	2009	2008
		(In millions)	
Consolidated:			
Sales and transfers of natural gas and oil produced net of production costs	$ (1,042)	$ (779)	$ (2,059)
Net changes in prices and production costs	1,734	(1,455)	(3,380)
Extensions, discoveries and improved recovery, less related costs	986	646	1,136
Changes in estimated future development costs	(226)	45	342
Previously estimated development costs incurred during the period	199	186	141
Revision of previous quantity estimates	315	(94)	(887)
Accretion of discount	220	310	622
Net change in income taxes	(934)	246	1,458
Purchases of reserves in place	73	121	36
Sales of reserves in place	(47)	(79)	(603)
Change in production rates, timing and other	(19)	199	(244)
Net change	$ 1,259	$ (654)	$ (3,438)
Unconsolidated Affiliate Four Star:			
Sales and transfers of natural gas and oil produced net of production costs	$ (83)	$ (137)	
Net changes in prices and production costs	70	(351)	
Extensions, discoveries and improved recovery, less related costs	1	1	
Changes in estimated future development costs	(1)	22	
Revision of previous quantity estimates	16	5	
Accretion of discount	18	57	
Net change in income taxes	(16)	137	
Change in production rates, timing and other	15	32	
Net change	$ 20	$ (234)	

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

Table of Contents

Schedule

SCHEDULE II
EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2010, 2009 and 2008
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2010					
Allowance for doubtful accounts	$ 8	$	$	$ (4)	$ 4
Valuation allowance on deferred tax assets	384	7(2)			391
Legal reserves[1]	66	14	(34)	(1)	45
Environmental reserves	189	26	(42)		173
Regulatory reserves[3]	74	21	(76)		19
2009					
Allowance for doubtful accounts	$ 9	$	$	$ (1)	$ 8
Valuation allowance on deferred tax assets	337	47(6)			384
Legal reserves[1]	73	20	(27)		66
Environmental reserves	204	25	(40)		189
Regulatory reserves[3]		74			74
2008					
Allowance for doubtful accounts	$ 17	$ (2)	$	$ (6)	$ 9
Valuation allowance on deferred tax assets	137	202(4)		(2)	337
Legal reserves[1]	460	(91)	(16)	(280) (5)	73
Environmental reserves	260	(11)	(44)	(1)	204
Regulatory reserves[3]	10		(10)		

(1) Amounts are net of related insurance receivables.

(2) Amounts reflect valuation allowances primarily associated with Brazil and Egypt net operating losses and the reversal of valuation allowances for federal and state net operating losses and state deferred tax assets.

(3) Reflects rate refund and settlement activity.

(4) Amounts reflect valuation allowances associated with Brazil net operating losses and ceiling test charges.

(5) Amount reclassified as postretirement liability.

(6) Amounts reflect valuation allowances primarily associated with Brazil net operating losses and ceiling test charges and the reversal of valuation allowances for state net operating losses and deferred tax assets.

Table of Contents

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, 2010, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (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 reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our 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 concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2010. 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 2010 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

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 2011 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.

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the captions Information about the Board of Directors and Committees Compensation Committee Interlocks and Insider Participation , Compensation Discussion and Analysis , Compensation Committee Report , Executive Compensation and Director Compensation in our Proxy Statement for the 2011 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 a Certain Beneficial Owner and Management and Equity Compensation Plan Information Table in our Proxy Statement for the 2011 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 2011 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 the Appointment of Ernst & Young LLP as our Independent Registered Public Accounting Firm 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 2011 Annual Meeting of Stockholders is incorporated herein by reference.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

1. Financial statements.

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

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

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;

- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;

- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and

- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

Undertaking

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 28th day of February 2011.

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 Chairman of the Board (Principal Executive Officer)	February 28, 2011
/s/ John R. Sult John R. Sult	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2011
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	February 28, 2011
/s/ Juan Carlos Braniff Juan Carlos Braniff	Director	February 28, 2011
/s/ David W. Crane David W. Crane	Director	February 28, 2011
/s/ Robert W. Goldman Robert W. Goldman	Director	February 28, 2011
/s/ Anthony W. Hall, Jr. Anthony W. Hall, Jr.	Director	February 28, 2011
/s/ Thomas R. Hix Thomas R. Hix	Director	February 28, 2011

/s/ Ferrell P. McClean	Director	February 28, 2011
Ferrell P. McClean		
/s/ Timothy J. Probert	Director	February 28, 2011
Timothy J. Probert		
/s/ Steven J. Shapiro	Director	February 28, 2011
Steven J. Shapiro		
/s/ J. Michael Talbert	Director	February 28, 2011
J. Michael Talbert		
/s/ Robert F. Vagt	Director	February 28, 2011
Robert F. Vagt		
/s/ John L. Whitmire	Director	February 28, 2011
John L. Whitmire		

Table of Contents

EL PASO CORPORATION
EXHIBIT INDEX
December 31, 2010

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.
3.B	By-laws effective as of May 6, 2009 (Exhibit 3.B to our Current Report on Form 8-K filed with the SEC on May 6, 2009).
*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.
*4.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock.
4.C	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.D	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.E	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.F	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.G	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 (Exhibit 4.H to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
4.H	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 (Exhibit 4.I to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
4.I	

	Sixteenth Supplemental Indenture, dated as of September 24, 2010, 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 September 24, 2010).
+10.A	1995 Compensation Plan for Non-Employee Directors Amended and Restated effective as of December 4, 2003 (Exhibit 10.A to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); 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); 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(Exhibit 10.A.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).

Exhibit Number	Description
*+10.B	Stock Option Plan for Non-Employee Directors Amended and Restated effective as of January 20, 1999.
*+10.B.1	Amendment No. 1 effective as of July 16, 1999 to the Stock Option Plan for Non-Employee Directors.
+10.B.2	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).
+10.B.3	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(Exhibit 10.C to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); 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); 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); 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	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); 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); 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); 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); Amendment No. 4 effective as of May 1, 2003 to the 2001 Omnibus Incentive Compensation Plan. (Exhibit 10.F.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); Amendment No. 5 effective as of March 8, 2004 to the 2001 Omnibus Incentive Compensation Plan (Exhibit 10.F.5 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009);. 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.E	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).
+10.F	

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.F.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); Amendment No. 3 effective December 15, 2004 to the Supplemental Benefits Plan(Exhibit 10.F.3 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); 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).

Exhibit Number	Description
*+10.G	Senior Executive Survivor Benefit Plan Amended and Restated effective as of August 1, 1998.
+10.G.1	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).
+10.G.2	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.H	Key Executive Severance Protection Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).; 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); 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); 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); Amendment No. 4 effective as of September 2, 2003 to the Key Executive Severance Protection Plan(Exhibit 10.I.4 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009); 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.I	2004 Key Executive Severance Protection Plan effective as of March 9, 2004 (Exhibit 10.I to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); 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.J	Director Charitable Award Plan Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010); 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.J.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
+10.K	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 (Exhibit 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.L	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

Exhibit Number	Description
	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.M	Form of Indemnification Agreement of each member of the Board of Directors effective November 7, 2002 or the effective date such director was elected to the Board of Directors, whichever is later(Exhibit 10.T to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
+10.N	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.O	Indemnification Agreement executed by El Paso for the benefit of Douglas L. Foshee, effective December 15, 2004 (Exhibit 10.R to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
*+10.P	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors effective as of May 26, 2005.
+10.P.1	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).
+10.P.2	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.P.3	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 (Exhibit 10.Y.1 to our Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on March 2, 2009).
+10.Q	El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated effective May 19, 2010 (incorporated by reference to Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 20, 2010).
*10.R	Form of stock option and restricted stock award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan.
*10.R.1	

	Form of performance share award letter under the El Paso Corporation 2005 Omnibus Incentive Compensation Plan.
*+10.S	2005 Supplemental Benefits Plan effective as of January 1, 2005.
+10.S.1	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.S.2	Amendment No. 2 effective as of January 1, 2008 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, 2008, filed with the SEC on March 2, 2009).
10.T	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.,

Table of Contents

Exhibit Number	Description
	as administrative agent and as collateral agent (Exhibit 10.V to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
10.U	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.T.1 to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 1, 2010).
10.V	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.W	Credit Agreement dated as of May 3, 2010 among Ruby Pipeline, L.L.C, as the Borrower, Société Générale, as the Administrative Agent, Deutsche Bank Trust Company Americas, as the Common Security Trustee, Construction/Term Loan Lenders, DSRA Issuing Banks, and Revolving Loan Lender/Issuing Bank (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.X	Non-Completion Loan Guaranty by El Paso Corporation, as the Guarantor, in favor of Société Générale as the Administrative Agent, dated as of May 3, 2010 (incorporated by reference to Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.Y	Registration Rights Agreement dated September 24, 2010 (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).
*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 Oil & Gas Company and Citrus Corp. and Subsidiaries)
*23.C	Consent of Ryder Scott Company, L.P.
*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 Company, L.P. reserve report for El Paso Exploration & Production Company and Four Star Oil & Gas Company as of December 31, 2010.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Schema Document.
*101.CAL	XBRL Calculation Linkbase Document.
*101.DEF	XBRL Definition Linkbase Document.
*101.LAB	XBRL Labels Linkbase Document.
*101.PRE	XBRL Presentation Linkbase Document.