EL PASO CORP/DE
Form 10-Q
May 10, 2010

Table of Contents

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 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

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 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.:

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

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

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

Common stock, par value $3 per share. Shares outstanding on May 3, 2010: 703,741,156

EL PASO CORPORATION
TABLE OF CONTENTS

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

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

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

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

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarter Ended March 31,	
	2010	**2009**
Operating revenues	$ 1,401	$ 1,484
Operating expenses		
Cost of products and services	53	61
Operation and maintenance	299	300
Ceiling test charges	2	2,068
Depreciation, depletion and amortization	218	256
Taxes, other than income taxes	69	68
	641	2,753
Operating income (loss)	760	(1,269)
Earnings from unconsolidated affiliates	28	19
Other income, net	60	22
Interest and debt expense	(243)	(255)
Income (loss) before income taxes	605	(1,483)
Income tax (benefit) expense	186	(526)
Net income (loss)	419	(957)
Net income attributable to noncontrolling interests	(31)	(12)
Net income (loss) attributable to El Paso Corporation	388	(969)
Preferred stock dividends of El Paso Corporation	9	9
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 379	$ (978)
Basic earnings (loss) per common share		
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.54	$ (1.41)
Diluted earnings (loss) per common share		
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.51	$ (1.41)
Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.05

See accompanying notes.

Table of Contents

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

	March 31, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents (include $111 in 2010 and $149 in 2009 held by variable interest entities)	$ 715	$ 635
Accounts and notes receivable		
Customer, net of allowance of $6 in 2010 and $8 in 2009	312	346
Affiliates	25	92
Other	208	115
Materials and supplies	169	175
Assets from price risk management activities	337	221
Deferred income taxes	204	298
Other	125	126
Total current assets	2,095	2,008
Property, plant and equipment, at cost		
Pipelines (include $1,512 in 2010 and $1,179 in 2009 held by variable interest entities)	20,208	19,722
Natural gas and oil properties, at full cost	21,032	20,846
Other	323	314
	41,563	40,882
Less accumulated depreciation, depletion and amortization	23,124	22,987
Total property, plant and equipment, net	18,439	17,895
Other assets		
Investments in unconsolidated affiliates	1,725	1,718
Assets from price risk management activities	156	123
Other	776	761
	2,657	2,602
Total assets	$ 23,191	$ 22,505

See accompanying notes.

Table of Contents

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

	March 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 427	$ 459
Affiliates	5	7
Other	410	424
Short-term financing obligations, including current maturities	622	477
Liabilities from price risk management activities	221	269
Asset retirement obligations	155	158
Accrued interest	242	208
Other	617	684
Total current liabilities	2,699	2,686
Long-term financing obligations, less current maturities	13,416	13,391
Other		
Liabilities from price risk management activities	403	462
Deferred income taxes	444	339
Other	1,460	1,491
	2,307	2,292
Commitments and contingencies (Note 9)		
Preferred stock of subsidiary	145	145
Equity		
El Paso Corporation 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 716,159,760 shares in 2010 and 716,041,302 shares in 2009	2,148	2,148
Additional paid-in capital	4,497	4,501
Accumulated deficit	(2,804)	(3,192)
Accumulated other comprehensive loss	(706)	(718)
	(284)	(283)

Treasury stock (at cost); 14,820,145 shares in 2010 and 14,761,654 shares in 2009		
Total El Paso Corporation stockholders equity	3,601	3,206
Noncontrolling interests	1,023	785
Total equity	4,624	3,991
Total liabilities and equity	$ 23,191	$ 22,505

See accompanying notes.

Table of Contents

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

	Quarter Ended March 31, 2010	Quarter Ended March 31, 2009
Cash flows from operating activities		
Net income (loss)	$ 419	$ (957)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	218	256
Ceiling test charges	2	2,068
Deferred income tax expense (benefit)	194	(528)
Earnings from unconsolidated affiliates, adjusted for cash distributions	(13)	(8)
Other non-cash income items	(6)	14
Asset and liability changes	(244)	(36)
Net cash provided by operating activities	570	809
Cash flows from investing activities		
Capital expenditures	(833)	(759)
Cash paid for acquisitions, net of cash acquired	(8)	
Net proceeds from the sale of assets and investments	1	210
Other	1	13
Net cash used in investing activities	(839)	(536)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	775	842
Payments to retire long-term debt and other financing obligations	(617)	(244)
Net proceeds from issuance of noncontrolling interests	231	
Dividends paid	(16)	(44)
Distributions to noncontrolling interest holders	(19)	(10)
Distributions to holders of preferred stock of subsidiary	(5)	
Net cash provided by financing activities	349	544
Change in cash and cash equivalents	80	817
Cash and cash equivalents		
Beginning of period	635	1,024
End of period	$ 715	$ 1,841

See accompanying notes.

Table of Contents

EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(In millions)
(Unaudited)

	Quarter Ended March 31, 2010	Quarter Ended March 31, 2009
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning and end of period	$ 750	$ 750
Common stock:		
Balance at beginning and end of period	2,148	2,138
Additional paid-in capital:		
Balance at beginning of period	4,501	4,612
Dividends	(16)	(44)
Other, including stock-based compensation	12	14
Balance at end of period	4,497	4,582
Accumulated deficit:		
Balance at beginning of period	(3,192)	(2,653)
Net income (loss) attributable to El Paso Corporation	388	(969)
Balance at end of period	(2,804)	(3,622)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(718)	(532)
Other comprehensive income (loss)	12	(73)
Balance at end of period	(706)	(605)
Treasury stock, at cost:		
Balance at beginning of period	(283)	(280)
Stock-based and other compensation	(1)	
Balance at end of period	(284)	(280)
Total El Paso Corporation stockholders equity at end of period	3,601	2,963
Noncontrolling interests:		
Balance at beginning of period	785	561
Distributions paid to noncontrolling interests	(19)	(10)
Issuances of noncontrolling interests	231	
Net income attributable to noncontrolling interests (Note 11)	26	12

Balance at end of period	1,023	563
Total equity at end of period	$ 4,624	$ 3,526

See accompanying notes.

Table of Contents

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

	Quarter Ended March 31, 2010	Quarter Ended March 31, 2009
Net income (loss)	$ 419	$ (957)
Pension and postretirement obligations:		
Reclassification of actuarial gains during period (net of income taxes of $6 in 2010 and $4 in 2009)	13	7
Cash flow hedging activities:		
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $2 in 2010 and $1 in 2009)	(3)	2
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 in 2010 and $46 in 2009)	2	(82)
Other comprehensive income (loss)	12	(73)
Comprehensive income (loss)	431	(1,030)
Comprehensive income attributable to noncontrolling interests	(31)	(12)
Comprehensive income (loss) attributable to El Paso Corporation	$ 400	$ (1,042)

See accompanying notes.

Table of Contents

EL PASO CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles. You should read this report along with our 2009 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2010, and for the quarters ended March 31, 2010 and 2009, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2009, from the audited balance sheet filed in our 2009 Annual Report on Form 10-K. In our opinion, we have made adjustments, all of which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year.

Significant Accounting Policies

The following is an update of our significant accounting policies and accounting pronouncements issued but not yet adopted as discussed in our 2009 Annual Report on Form 10-K.

Transfers of Financial Assets. On January 1, 2010, we adopted accounting standard updates for financial asset transfers. Among other items, these updates require the sale of an entire financial asset or a proportionate interest in a financial asset in order to qualify for sale accounting. These changes were effective for sales of financial assets occurring on or after January 1, 2010. In January 2010, we terminated our prior accounts receivable sales programs under which we previously sold senior interests in certain of our pipeline accounts receivable to a third party financial institution (through wholly-owned special purpose entities). As a result, the adoption of these accounting standard updates did not have a material impact on our financial statements. Upon termination of the prior accounts receivable sales programs, we entered into new accounts receivable sales programs under which we sell certain of our pipeline accounts receivable in their entirety to the third party financial institution (through wholly-owned special purpose entities). The transfer of these receivables qualifies for sale accounting under the provisions of these accounting standard updates. We present the cash flows related to the prior and new accounts receivable sales programs as operating cash flows in our statements of cash flows. For further information, see Note 13.

Variable Interest Entities. On January 1, 2010, we adopted accounting standard updates for variable interest entities that revise how companies determine the primary beneficiary of these entities, among other changes. Companies are now required to use a qualitative approach based on their responsibilities and power over the entities operations, rather than a quantitative approach in determining the primary beneficiary as previously required. Additionally, the primary beneficiary is required to retrospectively present qualifying assets and liabilities of variable interest entities separately on the balance sheet. Other than the required change in presentation on our balance sheet, the adoption of these accounting standard updates did not have a material impact on our financial statements. For a further discussion of our involvement with variable interest entities, see Note 13.

2. Divestitures

During the first quarter of 2009, we completed the sale of our interests in the Porto Velho power generation facility in Brazil for total consideration of $179 million and the sale of non-core natural gas producing properties located in our Central and Western divisions for approximately $93 million. In April 2010, we completed the sale of our interests in Mexican pipeline and compression assets for approximately $300 million. We currently expect to record a pretax gain of approximately $80 million in the second quarter of 2010.

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 quarters ended March 31, 2010 and 2009, we recorded the following ceiling test charges:

	2010	2009
	(In millions)	
Full cost pool:		
U.S	$	$ 2,031
Brazil		28
Egypt	2	9
Total	$ 2	$ 2,068

During the first quarter of 2009, the calculation of these charges was based on spot commodity prices as of March 31, 2009, as required at that time. As a result of our adoption of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we now use 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 these 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.

4. Income Taxes

Income taxes for the quarters ended March 31 were as follows:

	2010	2009
	(In millions, except rates)	
Income tax (benefit) expense	$ 186	$ (526)
Effective tax rate	31%	35%

Effective Tax Rate. We compute interim period income taxes by applying an anticipated annual effective tax rate to our year-to-date income or loss, except for significant unusual or infrequently occurring items. Significant tax items are recorded in the period that the item occurs and changes in tax laws or rates are recorded in the period of enactment. Our effective tax rate is affected by items such as income attributable to nontaxable noncontrolling interests, dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the effect of state income taxes (net of federal income tax effects), and the effect of foreign income which can be taxed at different rates.

During the first quarter of 2010, our effective tax rate was lower than the statutory rate primarily due to income attributable to nontaxable noncontrolling interests partially offset by $18 million of additional deferred income tax expense from healthcare legislation enacted in March 2010 which reduces the tax deduction for retiree prescription drug expenses to the extent they are reimbursed under the Medicare subsidy program. During the first quarter of 2009, our effective tax rate was relatively consistent with the statutory rate.

5. Earnings Per Share

We calculated basic and diluted earnings (loss) per common share as follows for the quarters ended March 31:

	2010		2009	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ 388	$ 388	$ (969)	$ (969)
Preferred stock dividends of El Paso Corporation	(9)		(9)	(9)
Interest on preferred securities		3		
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 379	$ 391	$ (978)	$ (978)
Weighted average common shares outstanding	696	696	695	695
Effect of dilutive securities:				
Options and restricted stock		6		
Convertible preferred stock		58		
Trust preferred securities		8		
Weighted average common shares outstanding and dilutive securities	696	768	695	695
Basic and diluted earnings (loss) per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.54	$ 0.51	$ (1.41)	$ (1.41)

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 quarter ended March 31, 2010, certain of our employee stock options were antidilutive. For the quarter ended March 31, 2009, we incurred losses attributable to El Paso Corporation and, accordingly, excluded all of our potentially dilutive securities from the determination of diluted earnings per share.

6. Fair Value of Financial Instruments

On January 1, 2009, we adopted accounting standard updates 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, in 2009 as a result of adopting these new accounting updates.

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

Each of these levels is described below:

- Level 1 instruments fair values are based on quoted prices for the instruments in actively traded markets.

- 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).

- Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but their fair value also reflects adjustments for being in less liquid markets or having longer contractual terms.

Table of Contents

During the quarter ended March 31, 2010, there have been no changes to the types of instruments or the levels in which they are classified. For a further description of these levels and our corresponding instruments classified by level, see our 2009 Annual Report on Form 10-K.

Listed below are the fair values of our financial instruments that are recorded at fair value classified in each level at March 31, 2010 and December 31, 2009:

	March 31, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(In millions)				
Assets								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ 358	$	$ 358	$	$ 169	$	$ 169
Other natural gas derivatives		82	21	103		106	21	127
Power-related derivatives			21	21			37	37
Interest rate derivatives		11		11		11		11
Marketable securities invested in non-qualified compensation plans	20			20	20			20
Total assets	20	451	42	513	20	286	58	364
Liabilities								
Commodity-based derivatives								
Production-related natural gas and oil derivatives		(25)		(25)		(42)		(42)
Other natural gas derivatives		(124)	(118)	(242)		(153)	(133)	(286)
Power-related derivatives			(341)	(341)			(386)	(386)
Interest rate derivatives		(16)		(16)		(17)		(17)
Other			(31)	(31)			(31)	(31)
Total liabilities		(165)	(490)	(655)		(212)	(550)	(762)
Total	$ 20	$ 286	$ (448)	$ (142)	$ 20	$ 74	$ (492)	$ (398)

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter ended March 31, 2010:

	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
			(In millions)		
Assets	$ 58	$ (15)	$	$ (1)	$ 42
Liabilities	(550)	33	(4)	31	(490)
Total	$ (492)	$ 18	$ (4)	$ 30	$ (448)

(1) Includes approximately $18 million of net gains that had not been realized through settlements as of March 31, 2010.

(2) Includes approximately $3 million of net losses that had not been realized through settlements as of March 31, 2010.

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

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

	March 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 14,038	$ 14,481	$ 13,868	$ 14,151
Marketable securities invested in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(126)	(126)	(381)	(381)
Interest rate derivatives	(5)	(5)	(6)	(6)
Other derivatives	(31)	(31)	(31)	(31)
Other	17	17	17	17

As of March 31, 2010 and December 31, 2009, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represented fair value because of the short-term nature of these instruments. The carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on 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.

7. Price Risk Management Activities

Our price risk management activities relate primarily to derivatives entered into to hedge or otherwise reduce (i) the commodity price exposure on our natural gas and oil production and (ii) interest rate exposure on our long-term debt. We also hold other derivatives not intended to hedge these exposures. When we enter into derivative contracts, we may designate the derivative as either a cash flow hedge or a fair value hedge. Hedges of cash flow exposure are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to protect the fair value of a recognized asset, liability or firm commitment.

Financial Statement Presentation. For a detailed description on how our derivatives are reflected and accounted for on our balance sheet and statements of income, comprehensive income and cash flow, see our 2009 Annual Report on Form 10-K. The following table presents the fair value of our derivatives on a gross basis by contract type. We have not netted these contracts for counterparties where we have a legal right of offset or for cash collateral associated with these derivatives. At March 31, 2010 and December 31, 2009, cash collateral held was not material.

	Fair Value of Derivative Assets		Fair Value of Derivative Liabilities	
	March 31, 2010	December 31, 2009	March 31, 2010	December 31, 2009
	(In millions)			
Derivatives Designated as Hedges:				
Interest rate derivatives				
Cash flow hedges	$ 1	$ 1	$ (16)	$ (17)
Fair value hedges	10	10		
Total derivatives designated as hedges	11	11	(16)	(17)
Derivatives not Designated as Hedges:				
Commodity-based derivatives				

Production-related	421	239	(88)	(112)
Other natural gas	358	519	(497)	(678)
Power-related	30	57	(350)	(406)
Total commodity-based derivatives	809	815	(935)	(1,196)
Interest rate derivatives	13	10	(13)	(10)
Total derivatives not designated as hedges	822	825	(948)	(1,206)
Impact of master netting arrangements [1]	(340)	(492)	340	492
Total assets (liabilities) from price risk management activities	493	344	(624)	(731)
Other derivatives			(31)	(31)
Total derivatives	$ 493	$ 344	$ (655)	$ (762)

[1] Includes adjustments to net assets or liabilities to reflect master netting arrangements we have with our counterparties.

Commodity-Based Derivatives

Production-Related Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts; however, we are subject to commodity price risks on a portion of our forecasted production. As of March 31, 2010 and December 31, 2009, we have production-related derivatives on 261 TBtu and 313 TBtu of natural gas and 5,556 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 either intend to manage until their expiration or liquidate to the extent it is economical and prudent. None of these derivatives are designated as accounting hedges. As of March 31, 2010 and December 31, 2009, these derivative contracts include (i) natural gas contracts that obligate us to sell natural gas to power plants and have various expiration dates ranging from 2012 to 2019, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 104,750 MMBtu/d and (ii) derivative power contracts that require us to swap locational differences in power prices between three power plants in the Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub on approximately 3,700 GWh from 2010 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 in previous years to economically mitigate our exposure to commodity price changes on substantially all of these volumes, although we continue to have exposure to changes in locational price differences between the PJM regions.

Listed below are the impacts of our commodity-based derivatives to our income statement and statement of comprehensive income for the quarters ended March 31:

	2010		2009	
	Operating Revenues	Other Comprehensive Income	Operating Revenues	Other Comprehensive (Loss)
	(In millions)			
Production-related derivatives[1]	$ 253	$ 3	$ 394	$ (128)
Other natural gas and power derivatives not designated as hedges	17		55	
Total commodity-based derivatives[2]	$ 270	$ 3	$ 449	$ (128)

(1) During the quarters ended March 31, 2010 and 2009 we reclassified $3 million of accumulated other comprehensive loss and $128 million of accumulated other comprehensive income into

operating revenues on derivatives for which we removed the cash-flow hedging designation in 2008. Approximately $12 million of our accumulated other comprehensive loss will be reclassified to operating revenues over the next twelve months.

(2) We also had approximately $4 million and $1 million of losses for the quarters ended March 31, 2010 and 2009 recognized in operating expenses related to other derivative instruments not associated with our price risk management activities.

Interest Rate Derivatives

We have long-term debt with variable interest rates that exposes us to changes in market-based interest rates. As of March 31, 2010 and December 31, 2009, we had interest rate swaps, which are designated as cash flow hedges, that we used to convert the interest rate on approximately $166 million of debt from a LIBOR-based variable rate to a fixed rate of 4.56%.

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 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. As of March 31, 2010 and December 31, 2009, our hedges converted the interest rate on approximately $218 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18% and we also had interest rate swaps not designated as hedges with a notional amount of $222 million for which changes in the fair value of these swaps were substantially eliminated by offsetting swaps contracts.

Our interest rate derivatives did not have a significant impact to our interest expense or other comprehensive income (loss) during the first quarter of 2010 or 2009, and we did not record any ineffectiveness on these derivatives during these periods. We do not anticipate that the accumulated other comprehensive loss associated with these derivatives to be reclassified to interest expense during the next twelve months will be significant to our financial statements.

Table of Contents

Cross-Currency Derivatives

During the second quarter of 2009, our Euro-denominated debt matured and we settled all of our related cross-currency swaps. These cross-currency swaps were designated as fair value hedges of this debt, and for the quarter ended March 31, 2009, these swaps increased our interest expense by approximately $2 million and decreased our other income by approximately $24 million as a result of changing interest and foreign currency rates during the first quarter of 2009.

8. Debt, Other Financing Obligations and Other Credit Facilities

	March 31, 2010	December 31, 2009
	(In millions)	
Short-term financing obligations, including current maturities	$ 622	$ 477
Long-term financing obligations	13,416	13,391
Total	$ 14,038	$ 13,868

Changes in Financing Obligations. During the quarter ended March 31, 2010, we had the following changes in our financing obligations:

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Elba Express Company L.L.C. credit facility	variable	$ 19	$ 19
Ruby Holding Company loan commitment	7.000%	144	143
El Paso Pipeline Partners L.P. notes due 2020	6.500%	425	420
El Paso revolving credit facility	variable	193	193
Increases through March 31, 2010		$ 781	$ 775
Repayments, repurchases, and other			
El Paso Exploration and Production Company revolving credit facility	variable	$ (419)	$ (419)
El Paso revolving credit facility	variable	(193)	(193)
Other	various	1	(5)
Decreases through March 31, 2010		$ (611)	$ (617)

Credit Facilities. We have various credit facilities in place which allow us to borrow funds or issue letters of credit as noted in the table above or further discussed below. As of March 31, 2010, we had total available capacity under these facilities (not including capacity available under the El Paso Pipeline Partners, L.P. (EPB) $750 million revolving credit facility and all project financings) of approximately $1.9 billion.

The availability of borrowings under our credit agreements and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. These restrictions include potential limitations in the credit agreements of certain of our subsidiaries on their ability to declare and pay dividends and loan funds to us. Additionally, the revolving credit facility of our exploration and production subsidiary is collateralized by certain of our natural gas and oil properties and has a borrowing base subject to revaluation on a semi-annual basis. There have been no significant changes to our restrictive covenants from those disclosed in our 2009 Annual Report on Form 10-K, and as of March 31, 2010, we were in compliance with all of our debt covenants.

Letters of Credit. We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of March 31, 2010, we increased the total letter of credit capacity under certain existing letter of credit facilities to $350 million with a weighted average fixed facility fee of 6.50% and maturities ranging from December 2013 to September 2014. As of March 31, 2010, we had total outstanding letters of credit issued under all of our facilities of approximately $1.1 billion. Included in this amount is approximately $0.6 billion of letters of credit securing our recorded obligations related to price risk management activities.

Ruby Pipeline Financing. In May 2010, we closed on a 7-year amortizing $1.5 billion financing facility for our Ruby pipeline project that matures in June 2017. We have various conditions precedent to funding. Our initial interest rate on amounts borrowed will be 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 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. We entered into hedges that hedge at least 75 percent of the floating LIBOR interest rate exposure on this facility beginning in June 2011 and extending through the maturity of the facility. 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.

9. 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 (ERISA) and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. The trial court has dismissed the claims that our plan violated ERISA. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. In 2002, a lawsuit entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation* was filed in a federal court in Detroit, Michigan 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 were obligated to pay the amounts above the cap, but intend to pursue appellate options following the determination by the trial court of any damages incurred by the plaintiffs during the period when premium payments above the cap were paid by the retirees. We believe our accruals established for this matter are adequate.

Price Reporting Litigation. Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. While some of the cases have been agreed to, settled, and paid, several of the cases are in various stages of appellate proceedings as further described in our 2009 Annual report on Form 10-K. In this regard, in April 2010, the Tennessee Supreme Court dismissed the lawsuit entitled *Leggett, et al. v. Duke Energy Corporation, et al.* Our costs and legal exposure related to the remaining lawsuits and claims which have not yet been settled and paid are not currently determinable.

Gas Measurement Class Action. In 1999, a purported class action lawsuit entitled *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* was filed in the District Court of Stevens County, Kansas against a number of our subsidiaries. The complaint alleges that the defendants inaccurately measured the volume and heating content of gas that resulted in the underpayment of royalties to royalty owners on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. The court has denied motions for class certification, and the deadline for an appeal of this order has now passed. Our costs and legal exposure related to this lawsuit and claim 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, 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. One case has been dismissed. We settled 60 cases in 2008 and 2009 which were covered by insurance. We have reached an agreement in principle to settle another 26 cases, which will be substantially funded by insurance. Following dismissal of these settled cases, we will have seven lawsuits that remain. It is likely that our insurers will assert denial of coverage on the four most-recently filed cases. Our costs and legal exposure related to the remaining lawsuits are not currently determinable.

Table of Contents

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 March 31, 2010, we had approximately $48 million accrued, which has not been reduced by $2 million of related insurance receivables, for our outstanding legal and governmental proceedings.

Rates and Regulatory Matters

SNG Rate Case. In January 2010, the Federal Energy Regulatory Commission (FERC) approved Southern Natural Gas Company s (SNG s) settlement in which SNG (i) increased its base tariff rates, (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 June 2008, El Paso Natural Gas Company (EPNG) filed a rate case with the FERC proposing an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates effective January 1, 2009, subject to refund. In March 2010, EPNG filed an uncontested partial offer of settlement which was approved in April 2010. The settlement provides for an increase in EPNG s base tariff rates over rates existing prior to January 1, 2009. Under the terms of the settlement, EPNG agreed to file its next general rate case to be effective as early as April 1, 2011, but not later than April 1, 2012. As part of the settlement, EPNG made an initial refund to its customers in April 2010, with the remaining refunds to be paid during the remainder of 2010. The refunds to be paid are fully reserved. The settlement resolves all but four issues in the proceeding. A hearing on the remaining issues is scheduled for May 2010 and the outcome is not currently determinable.

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 March 31, 2010, we had accrued approximately $182 million for environmental matters, which has not been reduced by $23 million for amounts to be paid directly under government sponsored programs or through contractual arrangements with third parties. Our accrual includes approximately $178 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $4 million for related environmental legal costs. Of the $182 million accrual, $13 million was reserved for facilities we currently operate and $169 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $182 million to approximately $393 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:

	March 31, 2010	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 13	$ 19
Non-operating	153	333

Superfund	16	41
Total	$ 182	$ 393

Below is a reconciliation of our accrued liability from January 1, 2010 to March 31, 2010 (in millions):

Balance as of January 1, 2010	$ 189
Additions/adjustments for remediation activities	2
Payments for remediation activities	(9)
Balance as of March 31, 2010	$ 182

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 30 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 the remainder of 2010, we estimate that our total remediation expenditures will be approximately $39 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 $5 million in the aggregate for the remainder of 2010 through 2014.

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.

Guarantees and Other Contractual Commitments

Guarantees and Indemnifications. We are involved in various joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. We also periodically provide indemnification arrangements related to assets or businesses we have sold for which our potential exposure can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For a further discussion, see our 2009 Annual Report on Form 10-K. 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 8. 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 March 31, 2010, we have recorded obligations of $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.

Commitments, Purchase Obligations and Other Matters. In 2009, the FERC approved an amendment to the 1995 FERC settlement with Tennessee Gas Pipeline Company (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 March 31, 2010, TGP has refunded approximately $30 million to their customers.

Table of Contents

10. Retirement Benefits

Net Benefit Cost. The components of net benefit cost for our pension and postretirement benefit plans for the quarters ended March 31, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(In millions)			
Service cost	$ 5	$ 4	$	$
Interest cost	28	30	8	9
Expected return on plan assets	(39)	(43)	(3)	(3)
Amortization of net actuarial loss (gain)	19	11	(1)	
Net benefit cost	$ 13	$ 2	$ 4	$ 6

11. Equity and Preferred Stock of Subsidiary

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

	Common Stock ($0.01/Share)	Convertible Preferred Stock (4.99%/Year)
Amount paid through March 31, 2010	$ 7	$ 9
Amount paid in April 2010	$ 7	$ 9
Declared in April 2010:		
Date of declaration	April 1, 2010	April 1, 2010
Payable to shareholders on record	June 4, 2010	June 15, 2010
Date payable	July 1, 2010	July 1, 2010

Dividends on our common stock and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For the remainder of 2010, we expect dividends paid on our common and preferred stock 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. Our ability to pay dividends can be impacted by certain restrictions as further described in our 2009 Annual Report on Form 10-K.

Noncontrolling Interests. In March 2010, we contributed a 51 percent interest in both Southern LNG, 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 EPB in exchange for $810 million which included cash and 5.3 million EPB common units. EPB raised the funds for the acquisition through the issuance of 9.9 million common units and the proceeds from a March 2010 debt offering. As of March 31, 2010, our ownership interest in EPB is 64 percent, including our 2 percent general partner interest. EPB makes quarterly distributions of available cash to its unitholders in accordance with its partnership agreement. During the quarters ended March 31, 2010 and 2009, EPB made cash distributions of $19 million and $10 million to its non-affiliated common unitholders. During the quarters ended March 31, 2010 and 2009, we have recorded $26 million and $12 million in net income attributable to noncontrolling interest holders on our income statement which represents the non-affiliated common unitholders share of EPB s income.

Preferred Stock of Subsidiary. 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 Gas Pipeline Company, L.L.C. (Cheyenne Plains). The preferred stock in Cheyenne Plains has been classified between liabilities and equity on our balance sheet since the events that require redemption of the preferred interest are not entirely within our control. The preferred dividend associated with GIP s preferred interest of $5 million was paid during the first quarter of 2010 and is reflected in net income attributable to noncontrolling interests on our income statement. For a further discussion of the Ruby transaction, see Note 13.

12. Business Segment Information

As of March 31, 2010, our business consists of two core segments, Pipelines and Exploration and Production, as well as our 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 March 31, 2010, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in four 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 terminal 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 as well as a number of miscellaneous businesses.

Our management uses earnings before interest expense and income taxes (EBIT) as a measure to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to evaluate more effectively the operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense, (ii) income taxes, and (iii) net income attributable to noncontrolling interests so that our investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income (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 March 31:

	2010	2009
	(In millions)	
Segment EBIT	$ 828	$ (1,237)
Corporate and Other	(11)	(3)
Consolidated EBIT	817	(1,240)
Interest and debt expense	(243)	(255)
Income tax benefit (expense)	(186)	526
Net income (loss) attributable to El Paso Corporation	388	(969)
Net income attributable to noncontrolling interests	31	12
Net income (loss)	$ 419	$ (957)

Table of Contents

The following table reflects our segment results for the quarters ended March 31 (in millions):

	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate and Other[1]	Total
			(In millions)		
2010					
Revenue from external customers	$ 724	$ 427(2)	$ 249	$ 1	$ 1,401
Intersegment revenue	13	220(2)	(230)	(3)	
Operation and maintenance	184	97	2	16	299
Ceiling test charges		2			2
Depreciation, depletion and amortization	106	107		5	218
Earnings from unconsolidated affiliates	22			6	28
EBIT	421	390	17	(11)	817
2009					
Revenue from external customers	$ 721	$ 574(2)	$ 188	$ 1	$ 1,484
Intersegment revenue	12	126(2)	(135)	(3)	
Operation and maintenance	183	109	1	7	300
Ceiling test charges		2,068			2,068
Depreciation, depletion and amortization	104	150		2	256
Earnings (losses) from unconsolidated affiliates	21	(9)		7	19
EBIT	396	(1,685)	52	(3)	(1,240)

(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. During the quarters ended

March 31, 2010 and 2009, we recorded an intersegment revenue elimination of $3 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $253 million and $394 million for the quarters ended March 31, 2010 and 2009 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.

Total assets by segment are presented below:

	March 31, 2010	December 31, 2009
	(In millions)	
Pipelines	$ 17,748	$ 17,324
Exploration and Production	4,232	4,025
Marketing	298	345

Total segment assets	22,278	21,694
Corporate and Other	913	811
Total consolidated assets	$ 23,191	$ 22,505

Table of Contents

13. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby. We consolidate our investment in Ruby Pipeline Holding Company, L.L.C. (Ruby) 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) has entered into a loan commitment to provide $405 million of project funding to Ruby, $360 million of which has been borrowed as of March 31, 2010, (ii) has contributed $145 million in exchange for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in a holding company of Cheyenne Plains, and (iii) will provide an additional $150 million of preferred equity contributions to Ruby after obtaining all FERC approvals as well as securing approximately $1.4 billion of third party financing. In April 2010, we received certification from the FERC authorizing the project. In May 2010, we closed $1.5 billion of third party project financing; however, the drawing on this financing is contingent on certain conditions. Cheyenne Plains is also a variable interest entity we consolidate as its primary beneficiary. GIP will hold their 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 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 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 August 2011 and/or completing financing, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining investment. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in EPB. For a further discussion of our Ruby transaction, refer to our 2009 Annual Report on Form 10-K.

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 Programs. 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 quarter ended March 31, 2009, we received $252 million of cash related to the sale of the senior interests, collected $272 million from the subordinated interests we retained in the receivables, and recognized a loss of less than $1 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 are reflected in accounts receivable in 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 in our statement of cash flows.

In 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). As of March 31, 2010, the third-party financial institution held $217 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. Our ability to recover this additional amount is based solely on the collection of the underlying receivables. During the first quarter of 2010, we received $455 million of cash up front from the sale of the receivables and received an additional $237 million of cash upon the collection of the underlying receivables. As of

March 31, 2010, we had not collected approximately $96 million related to our accounts receivable sales, which is reflected as other accounts receivable in 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 less than $1 million on our accounts receivable sales during the first quarter of 2010. Because the cash received up front and the cash received as the underlying receivables are collected both are related to the sale or ultimate collection of the underlying receivables, and 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 in 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 quarters ended March 31, 2010 and 2009.

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 direct its overall activities (and do not absorb a majority of its expected losses) since our receivables do not comprise a significant portion of its operations.

Table of Contents

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

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

	Investment		Earnings (Losses) from Unconsolidated Affiliates Quarter Ended March 31,	
	March 31, 2010	December 31, 2009	2010	2009
	(In millions)		(In millions)	
Net Investment and Earnings (Losses)				
Four Star [1]	$ 437	$ 450	$	$ (10)
Citrus	644	630	15	14
Gulf LNG[2]	279	285		
Gasoductos de Chihuahua[3]	190	184	6	6
Bolivia-to-Brazil Pipeline	109	105	5	4
Other	66	64	2	5
Total	$ 1,725	$ 1,718	$ 28	$ 19

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $10 million and $12 million for the quarters ended March 31, 2010 and 2009.

(2) As of March 31, 2010 and December 31, 2009, we had outstanding advances and receivables of $63 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. See Note 2.

	Quarter Ended March 31, 2010	2009
	(In millions)	
Summarized Financial Information		
Operating results data:		
Operating revenues	$ 132	$ 123
Operating expenses	73	68
Income from continuing operations and net income	38	35

We received distributions and dividends from our unconsolidated affiliates of $15 million and $12 million for the quarters ended March 31, 2010 and 2009. Included in these amounts are returns of capital of less than $1 million and approximately $1 million for the quarters ended March 31, 2010 and 2009. Our revenues and charges with unconsolidated affiliates were not material during the quarters ended March 31, 2010 and 2009.

Other Investment-Related Matters. We currently have outstanding disputes and other matters related to an investment in a Brazilian power plant facility (Manaus/Rio Negro) formerly owned by us. We have filed a lawsuit to collect amounts due to us (approximately $65 million of Brazilian reais-denominated accounts receivable). The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable. We also have a dispute with respect to whether $68 million of Brazilian reais-denominated ICMS taxes that were assessed are due on payments received from the plant s power purchaser from 1999 to 2001. The power utility is currently indemnifying us with respect to this assessment. The resolution of this lawsuit and tax dispute could require us to record additional losses in the future. Additionally, we have exposure on our Bolivia-to-Brazil pipeline investment related to regional and political events in Bolivia that could adversely impact our investment in this pipeline project. As new information becomes available or future material developments arise, we could be required to record an impairment of our investment. No material change in the status of or our exposure to any of these matters has occurred since the filing of our 2009 Annual Report on Form 10-K where they are discussed further.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2009 Annual Report on Form 10-K, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

Overview and Outlook

During the quarter ended March 31, 2010, both our pipeline and exploration and production operations provided a strong base of earnings and operating cash flow. In our pipeline business, approximately 80 percent of the revenues are collected in the form of demand or reservation charges which are not dependent upon commodity prices or throughput levels. In 2010, we expect our pipelines rates to remain relatively stable, with the majority of our pipelines not having any outstanding rate cases pending before the FERC. In our exploration and production business, total combined production volumes were down approximately 3 percent compared to the same period in 2009, but were up approximately 5 percent compared to the fourth quarter of 2009. In addition, in the first quarter of 2010, we also benefited from our natural gas derivative contracts. We also entered into additional hedges on our anticipated oil and natural gas production and have financial derivative contracts in place primarily related to our 2010-2011 production that provide downside price protection while still allowing for potential upside. As of March 31, 2010, we had 123 TBtu of natural gas hedges with an average floor price of $6.33 per MMBtu, 73 TBtu of natural gas hedges with an average ceiling price of $6.80 per MMBtu and 3,548 MBbls of crude oil swaps with an average floor price of $76.32 per barrel and an average ceiling price of $82.01 per barrel on our remaining anticipated 2010 production, although most of our natural gas hedges are on production that occurs in the first nine months of the year. 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 provide cash flows from operations.

We have made significant progress on our 2010 objectives, substantially completing our 2010 financing plan. During 2010, we received certification from the FERC authorizing the Ruby pipeline project and closed on $1.5 billion in Ruby project financing described further below. We currently expect to receive the remaining approvals to commence construction of our Ruby pipeline project in the second quarter of 2010; however, delays in receiving such authorizations could negatively impact our construction schedule and costs. During 2010, we also received $0.7 billion in cash in conjunction with contributing ownership interests in SLNG and Elba Express to our master limited partnership (MLP) and sold our interests in Mexican pipeline and compression assets for approximately $0.3 billion.

Our 2010 capital program consists of $2.9 billion related to our pipeline business (the largest portion relating to 100% of the anticipated construction cost of our Ruby pipeline project) and approximately $1.1 billion related to our exploration and production business. In our pipeline business, we continue to make progress on other backlog growth projects in addition to our Ruby pipeline project, having placed additional pipeline projects in service on time and on budget during the first quarter of 2010. In our exploration and production business, we will remain focused on targeting our capital towards more unconventional resource plays, with approximately one-half of our domestic capital program targeted for the Haynesville, Altamont and Eagle Ford areas in 2010. While our overall 2010 capital requirements are significant, our 2011 requirements decline significantly and by the end of 2011 most of our pipeline backlog will be placed in service. Additionally, for the remainder of 2010 we have $255 million of debt that will mature (excluding Ruby debt of approximately $360 million which we anticipate will convert to Ruby preferred equity).

As of March 31, 2010, we had approximately $2.4 billion of available liquidity (exclusive of approximately $0.4 billion of combined cash/credit facility capacity of EPB and Ruby) and believe we are well positioned to meet our obligations based on the anticipated performance of our core businesses, our financing actions taken to date and our available liquidity. We will, however, continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements.

Table of Contents

Segment Results

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 our legacy trading activities. 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 as well as a number of miscellaneous businesses.

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. 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 so that our investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income (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 the quarters ended March 31:

	2010	2009
	(In millions)	
Segment		
Pipelines	$ 421	$ 396
Exploration and Production	390	(1,685)
Marketing	17	52
Segment EBIT	828	(1,237)
Corporate and Other	(11)	(3)
Consolidated EBIT	817	(1,240)
Interest and debt expense	(243)	(255)
Income tax benefit (expense)	(186)	526
Net income (loss) attributable to El Paso Corporation	388	(969)
Net income attributable to noncontrolling interests	31	12
Net income (loss)	$ 419	$ (957)

Table of Contents

Pipelines Segment

Overview and Operating Results. During the first quarter of 2010, we continued to deliver strong operational and financial performance across all pipelines. Our first quarter 2010 EBIT increased 6 percent from the first quarter 2009 benefiting primarily from several expansion projects placed in service in 2010 and 2009. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the quarters ended March 31, 2010 and 2009, or that could potentially impact EBIT in future periods.

	2010	2009
	(In millions, except for volumes)	
Operating revenues	$ 737	$ 733
Operating expenses	(356)	(366)
Operating income	381	367
Other income, net	71	41
EBIT before adjustment for noncontrolling interests	452	408
Net income attributable to noncontrolling interests	(31)	(12)
EBIT	$ 421	$ 396
Throughput volumes (BBtu/d)[1]	18,811	19,704

(1) Throughput volumes include our proportionate share of unconsolidated affiliates and exclude intrasegment activities.

	Variance			
	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)			
Expansions	$ 28	$ (5)	$ 35	$ 58
Reservation and usage revenues	2			2
Gas not used in operations and revaluations	(29)	14		(15)
Operating and general and administrative expenses		4		4
Loss on long-lived assets		(10)		(10)
Hurricanes		4		4
Other[1]	3	3	(5)	1
	4	10	30	44

Total impact on EBIT before adjustment for noncontrolling interests				
Net income attributable to noncontrolling interests			(19)	(19)
Total impact on EBIT	$ 4	$ 10	$ 11	$ 25

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

Expansions. During the first quarter of 2010, we made progress on our backlog of expansion projects and benefited from increased reservation revenues due to projects placed in service in 2009 and 2010. These projects included the Carthage expansion project, the Totem Gas Storage facility, the Concord Lateral expansion and the Wyoming Interstate (WIC) Piceance Lateral expansion. We currently expect to place the Elba Expansion III storage facility in service during the summer of 2010 and the Colorado Interstate Gas (CIG) Raton 2010 project in service by the end of 2010. During the first quarter of 2010, we also benefited from an increase in allowance for funds used during construction on our expansion projects.

Table of Contents

Listed below are significant updates to our backlog of projects discussed in our 2009 Annual Report on Form 10-K.

Ruby Pipeline Project. In April 2010, we received certification from the FERC authorizing the project and anticipate receiving approval to proceed with the project in the second quarter of 2010.

CIG Raton 2010 Expansion. In April 2010, CIG received certificate authorization from the FERC to construct the expansion.

Elba Expansion III/ Elba Express. In March 2010, Phase A of both the Elba Expansion III vaporization facilities and the Elba Express pipeline project were placed in service.

TGP Northeast Upgrade Project. In February 2010, TGP entered into precedent agreements with two shippers to provide 636,000 MMBtu/d of additional firm transportation service from receipt points in the Marcellus Shale basin to an interconnect in New Jersey. Total estimated cost of this project is approximately $416 million.

TGP 300 Line Expansion. In July 2009, TGP filed an application with the FERC for certificate authorization to construct the 300 Line expansion project and anticipate receiving the approval in the second quarter of 2010. In February 2010, the FERC issued a favorable environmental assessment.

Reservation and Usage Revenues. During the quarter ended March 31, 2010, our reservation and usage revenues increased as compared to the same period in 2009 due to higher tariff rates effective September 1, 2009 pursuant to SNG s rate case settlement. Offsetting this was a decrease of approximately $12 million primarily due to lower prices realized on the sale of transportation capacity on our EPNG system and lower throughout volumes.

During the quarter ended March 31, 2010, throughput volumes on the EPNG system decreased compared to the same period in 2009. This was due, in part, to a decrease in natural gas and electric generation demand due to weak macroeconomic conditions in the southwestern U.S., increased competition in EPNG s California and Arizona market areas and reduced basis differentials. Although fluctuations in throughput on our pipeline systems have a limited effect on our short-term results since a material portion of our revenues are derived from firm reservations charges, it can 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 system 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 our transportation rates in order to renew certain firm transportation contracts should these conditions continue. If we determine there is a significant change in our costs or billing determinants on any of our pipeline systems, we will have the option to file rate cases with the FERC on certain of our pipelines to recover our prudently incurred costs.

Gas Not Used in Operations and Revaluations. During the quarter ended March 31, 2010, lower retained fuel volumes in excess of fuel used in operations, lower realized prices on operational sales, lower electric compression utilization, and lower fuel imbalance revaluations, settlement and other gas balance related items resulted in lower EBIT as compared with the same period in 2009. Our future earnings may be impacted positively or negatively depending on fluctuations in natural gas prices related to the revaluation of under or over recoveries, imbalances and system encroachments. We continue to explore options to minimize the price volatility associated with these operational pipeline activities.

Operating and General and Administrative Expenses. During the quarter ended March 31, 2010, our operating and general and administrative expenses were lower compared to the same period in 2009 primarily due to the impact of cost savings initiatives in 2010.

Loss on Long-Lived Assets. During the first quarter of 2010, we recorded an impairment of approximately $10 million primarily related to our decision not to continue with a storage project due to current market conditions.

Hurricanes. For the quarter ended March 31, 2009, our EBIT was unfavorably impacted by repair costs that were not recoverable from insurance due to losses not exceeding self-retention levels.

Net Income Attributable to Noncontrolling Interests. During the quarter ended March 31, 2010, our net income attributable to noncontrolling interests increased as compared to the same period in 2009 due primarily to (i) additional public common units issued by our majority-owned MLP in July 2009 and January 2010 and (ii) our contribution of an additional 18 percent interest in CIG to our MLP in July 2009. In late March 2010, we also contributed a 51 percent interest in SLNG and Elba Express to our MLP. As of March 31, 2010, we owned 64 percent of the MLP, including our 2 percent general partner interest.

Other Regulatory Matters. Our pipeline systems periodically file for changes in their rates, which are subject to 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 2013.

In January 2010, the FERC approved SNG s settlement in which SNG (i) increased its base tariff rates, (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.

In June 2008, EPNG filed a rate case with the FERC proposing an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates effective January 1, 2009, subject to refund. In March 2010, EPNG filed an uncontested partial offer of settlement which was approved in April 2010. The settlement provides for an increase in EPNG s base tariff rates over rates existing prior to January 1, 2009. Under the terms of the settlement, EPNG agreed to file its next general rate case to be effective as early as April 1, 2011, but not later than April 1, 2012. As part of the settlement, EPNG made an initial refund to its customers in April 2010, with the remaining refunds to be paid during the remainder of 2010. The refunds to be paid are fully reserved. The settlement resolves all but four issues in the proceeding. A hearing on the remaining issues is scheduled for May 2010 and the outcome is not currently determinable.

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. For a further discussion of our business strategy in our exploration and production business, see our 2009 Annual Report on Form 10-K.

Our profitability and performance is impacted by (i) changes in commodity prices, (ii) industry-wide changes in the cost of drilling and oilfield services, and (iii) the effect of hurricanes and other weather impacts on our daily production, operating, and capital costs. To the extent possible, we attempt to mitigate these factors. As part of our risk management activities, we maintain derivative contracts to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Quarter Ended March 31, 2010

Production. Our average daily production for the three months ended March 31, 2010 was 781 MMcfe/d, including 64 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the quarters ended March 31:

	2010	**2009**
	MMcfe/d	
United States		
Central	320	245
Western	151	164
Gulf Coast	225	313
International		
Brazil	21	9
Total Consolidated	717	731
Four Star	64	72
Total Combined	781	803

In the first quarter of 2010, production volumes increased in our Central division as a result of our successful Arklatex drilling programs, including the Haynesville Shale. As of March 31, 2010 and December 31, 2009, we had 29 operated producing wells and 20 operated producing wells in the Haynesville Shale. In our Western division, production volumes decreased primarily due to natural declines in the Altamont-Bluebell-Cedar Rim Field and the Rockies, partially offset by additional production volumes from an acquisition in late 2009. Production volumes in our Gulf Coast division decreased primarily due to natural declines and lower levels of drilling activities. In Brazil, our production volumes increased due to new production from our Camarupim Field.

Table of Contents

2010 Drilling Results

Our drilling results for the quarter ended March 31, 2010 are as follows:

Domestic. We achieved a 98 percent success rate on 60 gross wells drilled. By division, these results were as follows:

	Success Rate	Gross Wells Drilled
Central	100%	51
Western	100%	4
Gulf Coast	80%	5

International

Brazil. In Brazil, our drilling operations are primarily in the Camamu and Espirito Santo Basins. During the first quarter of 2010, we continued the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development in the Pinauna Field in the Camamu Basin. The timing will be dependent on the receipt of all required regulatory approvals. In the Espirito Santo Basin, the Camarupim Field began production from the second and third wells of a four well development program. We continue to work with Petrobras to connect the fourth well and anticipate bringing the well on production by the end of 2010. We also continue to engage in exploratory efforts with Petrobras in the ES-5 block. As of March 31, 2010, we have total capitalized costs in Brazil of approximately $330 million, of which $146 million are unevaluated capitalized costs.

Egypt. During the first quarter of 2010, we participated in drilling a fourth exploratory well in the South Alamein block. The well encountered oil shows but was temporarily plugged as we continue to evaluate the results. We also participated in spudding a fifth exploratory well in the South Alamein block in March 2010. In our South Mariut block, we relinquished approximately 30 percent of our acreage resulting in a $2 million non-cash charge. Additionally, we relinquished the South Feiran concession in March 2010. As of March 31, 2010, we have total capitalized costs in Egypt of approximately $73 million, all of which are unevaluated.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil production volumes. 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 quarter ended March 31, 2010, cash operating costs per unit decreased to $1.88/Mcfe as compared to $2.00/Mcfe during the same period in 2009, primarily due to lower lease operating expenses.

Capital Expenditures. Our total natural gas and oil capital expenditures were $235 million for the quarter ended March 31, 2010, of which $220 million were domestic capital expenditures.

Table of Contents

Outlook for 2010

For the full year 2010, we expect the following on a worldwide basis.

Capital expenditures, excluding acquisitions, of approximately $1.1 billion. Of this total, we expect to spend approximately $0.9 billion on our domestic program and approximately $0.2 billion in Brazil and Egypt.

Average daily production volumes for the year of approximately 740 MMcfe/d to 780 MMcfe/d, which includes approximately 60 MMcfe/d to 65 MMcfe/d from Four Star. Production volumes from our Brazil operations are expected to increase to between 35 MMcfe/d and 45 MMcfe/d in 2010.

Average cash operating costs between $1.80/Mcfe and $2.10/Mcfe for the year; and

Depreciation, depletion and amortization rate between $1.65/Mcfe and $1.85/Mcfe.

Price Risk Management Activities

We enter into derivative contracts on our natural gas and oil production to stabilize cash flows, reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge our entire price risk, 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.

For 2010, the majority of our natural gas derivative contracts are for the first nine months. As a result, we have greater price exposure during the fourth quarter of 2010. The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of March 31, 2010.

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)							
							Texas Gulf Coast		Raton		Western Rockies		Central Mid-Continent	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
Natural Gas														
2010	39	$ 6.19	84	$ 6.40	34	$ 7.50	36	$(0.40)	15	$(0.78)	7	$(1.93)	7	$(0.74)
2011	16	$ 5.99	120	$ 6.00	120	$ 9.00	33	$(0.13)	22	$(0.25)				
2012	2	$ 3.93												
Oil														
2010	2,310	$77.02	1,238	$75.00	1,238	$91.33								
2011			2,008	$80.00	2,008	$95.56								

(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.

Internationally, production from the Camarupim Field in Brazil is sold at a price that is adjusted quarterly based on a basket of fuel oil prices. In addition to the amounts included in the table above, as of March 31, 2010, we have fuel oil swaps that effectively lock in a price of approximately $4.00 per MMBtu on approximately 8 TBtu of projected Brazilian natural gas production in 2010.

In April 2010, we entered into collars on 11 TBtu of our anticipated 2011 natural gas production with a floor price of $6.00 per MMBtu and an average ceiling price of $6.15 per MMBtu for which we paid approximately $7 million in premiums. In addition, we entered into fixed price swaps on approximately 1.7 MMBbls of our anticipated 2011 oil production at an average price of $89.00 per barrel.

Table of Contents

Operating Results and Variance Analysis

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

	Quarter Ended March 31, 2010	Quarter Ended March 31, 2009
	(In millions)	
Physical sales		
Natural gas	$ 288	$ 252
Oil, condensate and NGL	93	46
Total physical sales	381	298
Realized and unrealized gains on financial derivatives(1)	253	394
Other revenues	13	8
Total operating revenues	647	700
Operating expenses		
Cost of products	10	5
Transportation costs	18	20
Production costs	69	78
Depreciation, depletion and amortization	107	150
General and administrative expenses	49	50
Ceiling test charges	2	2,068
Other	4	4
Total operating expenses	259	2,375
Operating income (loss)	388	(1,675)
Other income (expense)(2)	2	(10)
EBIT	$ 390	$ (1,685)

(1) Includes $(3) million and $128 million of amounts reclassified from accumulated other comprehensive income (loss) associated with accounting hedges.

(2) 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.

Table of Contents

The table below provides additional detail of our volumes, prices, and costs per unit. We present (i) average realized prices based on physical sales of natural gas and oil, condensate and NGL as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements. Our average realized prices, including financial derivative settlements reflect cash received and/or paid during the period on settled financial derivatives based on the period the contracted settlements were originally scheduled to occur; however, these prices do not reflect the impact of any associated premiums paid to enter into certain of our derivative contracts.

	Quarter Ended March 31,		
	2010	**2009**	**Percent Variance**
Volumes			
Natural gas (MMcf)			
Consolidated volumes	56,147	56,862	(1)%
Unconsolidated affiliate volumes	4,214	4,860	(13)%
Oil, condensate and NGL (MBbls)			
Consolidated volumes	1,402	1,477	(5)%
Unconsolidated affiliate volumes	246	276	(11)%
Equivalent volumes			
Consolidated MMcfe	64,557	65,700	(2)%
Unconsolidated affiliate MMcfe	5,690	6,516	(13)%
Total combined MMcfe	70,247	72,216	(3)%
Consolidated MMcfe/d	717	731	(2)%
Unconsolidated affiliate MMcfe/d	64	72	(11)%
Total combined MMcfe/d	781	803	(3)%
Consolidated prices and costs per unit			
Natural gas ($/Mcf)			
Average realized price on physical sales	$ 5.13	$ 4.43	16%
Average realized price, including financial derivative settlements [1]	$ 6.04	$ 8.52	(29)%
Average transportation costs	$ 0.29	$ 0.34	(15)%
Oil, condensate and NGL ($/Bbl)			
Average realized price on physical sales	$ 66.28	$ 31.29	112%
Average realized price, including financial derivative settlements[1][2]	$ 65.04	$ 70.14	(7)%
Average transportation costs	$ 0.84	$ 0.93	(10)%
Production costs and other cash operating costs ($/Mcfe)			
Average lease operating expenses	$ 0.75	$ 0.89	(16)%
Average production taxes[3]	0.31	0.29	7%
Total production costs	$ 1.06	$ 1.18	(10)%
Average general and administrative expenses	0.76	0.76	%
Average taxes, other than production and income taxes	0.06	0.06	%
Total cash operating costs	$ 1.88	$ 2.00	(6)%

Depreciation, depletion and amortization ($/Mcfe)[4]	$	1.67	$	2.28	(27)%

[1] Premiums related to natural gas derivatives settled during the quarter ended March 31, 2010 were $52 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 $0.93/Mcf for the quarter ended March 31, 2010. We had no premiums related to natural gas derivatives settled during the quarter ended March 31, 2009, or related to oil derivatives settled during the quarters ended March 31, 2010 and 2009.

[2] Does not include approximately

$149 million received in the first quarter of 2009 related to the early settlement of oil derivative contracts originally scheduled to settle April through December of 2009.

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

(4) Includes $0.07 per Mcfe and $0.06 per Mcfe for the quarters ended March 31, 2010 and 2009 related to accretion expense on asset retirement obligations.

Table of Contents

Quarter Ended March 31, 2010 Compared to Quarter Ended March 31, 2009

Our EBIT for the quarter ended March 31, 2010 increased $2.1 billion as compared to the same period in 2009. The table below shows the significant variances of our financial results for the quarter ended March 31, 2010 as compared to the same period in 2009:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Higher realized prices in 2010	$ 40	$	$	$ 40
Lower volumes in 2010	(4)			(4)
Oil, condensate and NGL				
Higher realized prices in 2010	49			49
Lower volumes in 2010	(2)			(2)
Realized and unrealized gains on financial derivatives	(141)			(141)
Other revenues	5			5
Depreciation, depletion and amortization expense				
Lower depletion rate in 2010		40		40
Lower production volumes in 2010		3		3
Production costs				
Lower lease operating expenses in 2010		10		10
Higher production taxes in 2010		(1)		(1)
Ceiling test charges		2,066		2,066
Earnings from investment in Four Star			10	10
Other		(2)	2	
Total Variances	$ (53)	$ 2,116	$ 12	$ 2,075

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the first quarter of 2010, natural gas, oil, condensate and NGL revenues increased as compared to the same period in 2009 due to higher commodity prices partially offset by lower production volumes.

Realized and unrealized gains on financial derivatives. During the first quarter of 2010, we recognized net gains of $253 million compared to net gains of $394 million during the same period in 2009 due to higher natural gas and oil prices in 2010.

Depreciation, depletion and amortization expense. During the first quarter of 2010, 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 March 2009.

Production costs. Our production costs decreased during the first quarter of 2010 as compared to the same period in 2009 primarily due to lower lease operating expenses.

Ceiling test charges. In the first quarter of 2010, we recorded a non-cash ceiling test charge in our Egyptian full cost pool of $2 million as a result of the relinquishment of approximately 30 percent of our acreage in the South Mariut block. During the first quarter of 2009, we recorded total non-cash ceiling test charges of approximately $2.0 billion in our domestic full cost pool, $28 million in our Brazilian full cost pool and $9 million as a result of a dry hole drilled in the South Mariut block.

Other. Our equity earnings from Four Star increased by $10 million during the first quarter of 2010 as compared to the same period in 2009 primarily due to the impact of higher commodity prices.

32

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 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. Our contracts are described below and in further detail in our 2009 Annual Report on Form 10-K.

Power contracts. The primary unhedged exposure remaining in the Marketing segment relates to mark-to-market power contracts that extend through April 2016. The exposure relates to volatility in locational power prices within the PJM region.

Transportation-related contracts. The impact of these accrual-based contracts is based on our ability to use or remarket the contracted pipeline capacity. As of March 31, 2010, these contracts require us to pay demand charges of $38 million in 2010 and an average of $41 million per year between 2011 and 2014.

Natural gas contracts. As of March 31, 2010, we have long term gas supply contracts that obligate us to deliver natural gas to specified power plants. The accounting for these contracts is a combination of mark-to-market and accrual-based. These contracts are expected to have minimal future impact on this segment as we have substantially offset all of the fixed price exposure.

Operating Results

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

	2010	2009
	(In millions)	
Contracts Related to Legacy Trading Operations:		
Changes in fair value of power contracts	$ 18	$ 34
Natural gas transportation-related contracts:		
Demand charges	(9)	(9)
Settlements, net of termination payments	11	7
Changes in fair value of other natural gas derivative contracts	(1)	21
Total revenues	19	53
Operating expenses	(2)	(1)
Operating income and EBIT	$ 17	$ 52

Our first quarter 2010 results were impacted by an $18 million mark-to-market gain on our legacy power contracts due to changes in the locational power prices used to value the contracts. Our first quarter 2009 results were primarily driven by 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).

Table of Contents

Corporate and Other Expenses, Net

Our corporate and other activities include our general and administrative functions as well as a number of miscellaneous businesses. The following is a summary of significant items impacting the EBIT in our corporate and other activities for the quarters ended March 31:

	2010	2009
	(In millions)	
Income (Loss)		
Change in litigation, environmental and other reserves	$ (8)	$ (3)
Equity earnings	6	7
Other	(9)	(7)
Total EBIT	$ (11)	$ (3)

Litigation, Environmental, and Other Reserves. During the quarter ended March 31, 2010, we recorded mark-to-market losses of $4 million associated with an indemnification in conjunction with the sale of a legacy ammonia facility based on fluctuations in ammonia prices. These losses were based on increases in ammonia prices during the first quarter of 2010 compared to relatively flat prices in the first quarter of 2009. Changes in ammonia prices will continue to impact this contract, which could affect our results in the future.

We have a number of pending litigation 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.

Equity Earnings. During the quarters ended March 31, 2010 and 2009, our equity earnings were primarily from legacy power investments which are further described in our 2009 Annual Report on Form 10-K.

Other. Other includes non-cash pension costs and other benefit costs related to legacy activities. As previously disclosed, we anticipate an increase in our non-cash pension costs during 2010 primarily as a result of our pension plan asset performance during 2008. Overall losses on our pension assets will continue to be amortized into our future net benefit cost through 2011. Despite the increased expense, we do not anticipate making any contributions to our primary pension plan in 2010. For further discussion of our primary pension plan and related net benefit cost, see our 2009 Annual Report on Form 10-K.

Income Taxes

	Quarter Ended March 31,	
	2010	2009
	(In millions, except for rates)	
Income taxes.	$ 186	$ (526)
Effective tax rate	31%	35%

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 4.

Table of Contents

Commitments and Contingencies

Below is a summary of certain climate change and energy policies recently enacted or proposed that, if enacted, will likely impact our business. For a further discussion of our commitments and contingencies, see Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

Climate Change Legislation and Regulation. Legislative and regulatory efforts to address climate change and greenhouse gas (GHG) emissions are in various phases of discussions or implementation at international, federal, regional and state levels. We believe that legislation that either limits or sets a price on carbon emissions will increase demand for natural gas depending on the legislative provisions ultimately adopted. However, we also believe it is reasonably likely that the federal legislation being contemplated, as well as recently adopted and proposed federal regulations, would increase our cost of environmental compliance by requiring us to purchase emission allowances or offset credits, install additional equipment or change work practices, and could materially increase the cost of goods and services we purchase from suppliers due to their increased compliance costs. Although we believe that many of these costs should be recoverable in the rates charged by our pipelines and in the market price for natural gas that we sell, recovery through these mechanisms is still uncertain at this time.

The Environmental Protection Agency (EPA) has adopted regulations that require us to monitor and report certain GHG emissions from our operations on an annual basis. The EPA has proposed to further expand the monitoring and reporting requirements to additional natural gas transmission sources and to include onshore domestic exploration and production segments previously proposed to be exempt, which could materially increase the costs of our operations. The EPA has also proposed regulations pursuant to which GHG emissions would be regulated under the Clean Air Act in 2011. These proposed rules, if adopted, would likely have a material impact on our cost of operations, could require us to install new equipment to control emissions from our facilities, and could result in delays and negative impacts on our ability to obtain permits and other regulatory approvals with regard to existing and new facilities

It is uncertain what federal or state legislation or regulations will ultimately be adopted and whether they will withstand likely legal challenges. Therefore, the potential impact on our operations and construction projects remains uncertain.

Energy Legislation. In conjunction with these climate change proposals, there have been various federal and state legislative and regulatory proposals that would create additional incentives to move to a less carbon intensive footprint . Although it is reasonably likely that many of these proposals will be enacted over the next few years, we cannot predict the form of any laws and regulations that might be enacted, the timing of their implementation, or the precise impact on our operations or demand for natural gas. However, such proposals if enacted could negatively impact natural gas demand over the longer term.

Air Quality Regulations. In March 2009, the EPA proposed a rule that is expected to be finalized later in 2010 impacting emissions of hazardous air pollutants from reciprocating internal combustion engines and requiring us to install emission controls on our pipeline systems. As proposed, engines subject to the regulations would have to be in compliance by August 2013. Based upon that timeframe, we expect that we would begin incurring expenditures in late 2010, incur the majority of the expenditures in 2011 and 2012, and expend any remaining amounts in early 2013. Based on our expectation that the final rule will be similar to a recently adopted rule applicable to diesel engines, our current estimated impact is approximately $32 million in capital expenditures over the period from 2010 to 2013.

Liquidity and Capital Resources

Our focus has been to expand our core pipeline and exploration and production businesses and to build liquidity to fund that growth. Our primary sources of cash are cash flows generated from our operations and amounts available to us under our revolving credit facilities. As conditions warrant, we also generate funds through additional bank financings, project financings, capital market activities and asset sales. Our primary uses of cash are funding our capital expenditure programs, meeting operating needs and repaying debt when due or repurchasing debt when conditions warrant.

Available Liquidity and Liquidity Outlook for 2010. We have made significant progress on our 2010 objectives. During 2010, we received FERC approval authorizing our Ruby pipeline project and closed on $1.5 billion in third party Ruby project financing described below. We also received $0.7 billion in cash in conjunction with contributing ownership interests in SLNG and Elba Express to our MLP and sold our interests in Mexican pipeline and compression assets for approximately $0.3 billion. As a result of these actions and the committed funding from GIP, our partner in the Ruby pipeline project, we have substantially met our planned funding requirements for 2010. At March 31, 2010, our available liquidity was approximately $2.4 billion (approximately $0.5 billion cash and $1.9 billion of available credit facility), exclusive of approximately $0.4 billion of combined cash /credit facility capacity of EPB and Ruby.

As further discussed in our 2009 Annual Report on Form 10-K, in July 2009, we entered into an agreement with GIP, subject to various conditions prior to project completion, where they would invest up to $700 million for a 50 percent equity interest in Ruby. GIP s investment is comprised of (i) a series of 7 percent loans totaling $405 million ($360 million of which has been borrowed as of March 31, 2010), (ii) a $145 million contribution made in 2009 for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains, and (iii) up to an additional $150 million for convertible preferred equity in Ruby upon completion of various conditions. These conditions include the advancement of funds under the Ruby project financing, which we expect to occur in the second quarter of 2010 and final notice from the FERC to proceed. Delays in receiving such authorizations could negatively impact our construction schedule and costs. Additionally, if these conditions are not satisfied, GIP has the right to convert its Cheyenne Plains preferred interest into a common stock interest and/or be repaid in cash for its remaining investment in Cheyenne Plains or Ruby. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in our MLP. For additional information on our Ruby project, see below and Item 1, Financial Statements, Note 13.

In May 2010, we closed on a 7-year amortizing $1.5 billion financing facility for our Ruby pipeline project that matures in June 2017. We have various customary conditions precedent to funding. Our initial interest rate on amounts borrowed will be 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 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 instead of the rate previously mentioned. We entered into hedges that hedge at least 75 percent of the floating LIBOR interest rate exposure on this facility beginning in June 2011 and extending through the maturity of the facility. 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.

Our 2010 capital requirements are significant; however, our 2011 requirements decline significantly, and by the end of 2011 most of our pipeline backlog will be placed in service. In addition to our capital needs, for the remainder of 2010 we have $255 million of debt that will mature (excluding Ruby debt of approximately $360 million which we anticipate will convert into Ruby preferred equity).

Table of Contents

Our cash capital expenditures for the quarter ended March 31, 2010, and the amount of cash we expect to spend for the remainder of 2010 to grow and maintain our businesses are as follows:

	Quarter Ended March 31, 2010	2010 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.1	$ 0.3	$ 0.4
Growth[(1)]	0.4	2.1	2.5
Exploration and Production.	0.3	0.8	1.1
Other		0.1	0.1
	$ 0.8	$ 3.3	$ 4.1

(1) Our pipeline growth capital expenditures reflect 100 percent of the capital related to the Ruby pipeline project.

We believe the operating cash flows from our core businesses, our financing actions taken to date and our available liquidity will allow us to meet our operating, financing and capital needs for the remainder of 2010; however, we will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements, including considering additional opportunities with our MLP as the markets permit. 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, a further decline in commodity prices, or if any of our announced actions are not sufficient. If these events occur, additional adjustments to our plan and outlook may be required which could impact our financial and operating performance 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.

Overview of Cash Flow Activities. During the first quarter of 2010, we generated operating cash flow of approximately $0.6 billion primarily from our pipeline and exploration and production operations. We also generated approximately $0.4 billion in the first quarter as a result of the issuance of MLP common units and debt (in conjunction with our sale of additional pipeline assets to the MLP), and other consolidated project financings, net of revolver repayments. We used cash flow generated from these operating and financing activities to fund our pipeline and exploration and production capital programs and pay common and preferred dividends. For the quarter ended March 31, 2010, our cash flows from continuing operations are summarized as follows:

	2010
	(In billions)
Cash Flow from Operations	
Operating activities	

Net income	$	0.4
Other income adjustments		0.4
Change in assets and liabilities		(0.2)
Total cash flow from operations	$	0.6
Other Cash Inflows		
Financing activities		
Net proceeds from the issuance of long-term debt		0.8
Net proceeds from the issuance of noncontrolling interests		0.2
Total other cash inflows	$	1.0
Cash Outflows		
Investing activities		
Capital expenditures	$	0.8
Financing activities		
Payments to retire long-term debt and other financing obligations		0.6
Dividends and other		0.1
		0.7
Total cash outflows	$	1.5
Net change in cash	$	0.1

Table of Contents

Contractual Obligations

The following information provides updates to our contractual obligations, and should be read in conjunction with the information disclosed in our 2009 Annual Report on Form 10-K.

Commodity-Based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. Our commodity-based derivative contracts are not currently designated as accounting hedges and include options, swaps and other natural gas, oil and power purchase and supply contracts that are not traded on active exchanges. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of March 31, 2010:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Total Fair Value
			(In millions)		
Assets	$ 336	$ 132	$ 5	$ 9	$ 482
Liabilities	(215)	(235)	(104)	(54)	(608)
Total commodity-based derivatives	$ 121	$ (103)	$ (99)	$ (45)	$ (126)

The following is a reconciliation of our commodity-based derivatives for the quarter ended March 31, 2010:

	Commodity-Based Derivatives (In millions)
Fair value of contracts outstanding at January 1, 2010	$ (381)
Fair value of contract settlements during the period	(19)
Changes in fair value of contracts during the period	274
Net changes in contracts outstanding during the period	255
Fair value of contracts outstanding at March 31, 2010	$ (126)

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with the information disclosed in our 2009 Annual Report on Form 10-K, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2009 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

Production-Related Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risks of our forecasted sales of natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted 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 impacts on the 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)					
March 31, 2010	$ 333	$ 200	$ (133)	$ 471	$ 138
December 31, 2009	$ 127	$ (29)	$ (156)	$ 290	$ 163
Other commodity-based derivatives net assets (liabilities)					
March 31, 2010	$ (459)	$ (465)	$ (6)	$ (453)	$ 6
December 31, 2009	$ (508)	$ (517)	$ (9)	$ (500)	$ 8

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 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 Securities Exchange Act of 1934, as amended (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 March 31, 2010.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the first quarter of 2010 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2009 Annual Report on Form 10-K filed with the SEC.

Item 1A. Risk Factors

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

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words believe, expect, estimate, anticipate and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic and operating performance;
- operating income;
- management s plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in our forward-looking statements are described in our 2009 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. There have been no material changes in our risk factors since that report.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Table of Contents

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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 agreement 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.

Table of Contents

SIGNATURES

Pursuant to the requirements 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.

	EL PASO CORPORATION
Date: May 7, 2010	By: /s/ John R. Sult John R. Sult Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: May 7, 2010	By: /s/ Francis C. Olmsted, III Francis C. Olmsted, III Vice President and Controller (Principal Accounting Officer)

Table of Contents

EL PASO CORPORATION
EXHIBIT INDEX

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.

Exhibit Number	Description
*12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
*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.
*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.