EL PASO CORP/DE
Form 10-Q
August 09, 2010

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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 June 30, 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 August 2, 2010: 704,007,309

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

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

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.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Operating revenues	$ 1,018	$ 973	$ 2,419	$ 2,457
Operating expenses				
Cost of products and services	53	52	106	113
Operation and maintenance	285	264	584	564
Ceiling test charges		12	2	2,080
Depreciation, depletion and amortization	242	197	460	453
Taxes, other than income taxes	54	57	123	125
	634	582	1,275	3,335
Operating income (loss)	384	391	1,144	(878)
Earnings from unconsolidated affiliates	111	12	139	31
Other income, net	57	16	117	38
Interest and debt expense	(284)	(253)	(527)	(508)
Income (loss) before income taxes	268	166	873	(1,317)
Income tax (benefit) expense	82	66	268	(460)
Net income (loss)	186	100	605	(857)
Net income attributable to noncontrolling interests	(29)	(11)	(60)	(23)
Net income (loss) attributable to El Paso Corporation	157	89	545	(880)
Preferred stock dividends of El Paso Corporation	10	10	19	19
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 147	$ 79	$ 526	$ (899)
Basic earnings (loss) per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.21	$ 0.11	$ 0.75	$ (1.29)
Diluted earnings (loss) per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.21	$ 0.11	$ 0.72	$ (1.29)
Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.05	$ 0.02	$ 0.10

See accompanying notes.

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

	June 30, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents (include $19 in 2010 and $149 in 2009 held by variable interest entities)	$ 707	$ 635
Accounts and notes receivable		
Customer, net of allowance of $6 in 2010 and $8 in 2009	281	346
Affiliates	4	92
Other	166	115
Materials and supplies	169	175
Assets from price risk management activities	268	221
Deferred income taxes	189	298
Other	96	126
Total current assets	1,880	2,008
Property, plant and equipment, at cost		
Pipelines (include $1,781 in 2010 and $1,179 in 2009 held by variable interest entities)	20,598	19,722
Natural gas and oil properties, at full cost	21,274	20,846
Other	408	314
	42,280	40,882
Less accumulated depreciation, depletion and amortization	23,249	22,987
Total property, plant and equipment, net	19,031	17,895
Other assets		
Investments in unconsolidated affiliates	1,529	1,718
Assets from price risk management activities	135	123
Other	800	761
	2,464	2,602
Total assets	$ 23,375	$ 22,505

See accompanying notes.

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

	June 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 381	$ 459
Affiliates	7	7
Other	371	424
Short-term financing obligations, including current maturities	711	477
Liabilities from price risk management activities	204	269
Asset retirement obligations	149	158
Accrued interest	214	208
Other	656	684
Total current liabilities	2,693	2,686
Long-term financing obligations, less current maturities	13,083	13,391
Other		
Liabilities from price risk management activities	451	462
Deferred income taxes	496	339
Other	1,434	1,491
	2,381	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 719,355,123 shares in 2010 and 716,041,302 shares in 2009	2,158	2,148
Additional paid-in capital	4,487	4,501
Accumulated deficit	(2,647)	(3,192)
Accumulated other comprehensive loss	(730)	(718)
Treasury stock (at cost); 15,388,683 shares in 2010 and 14,761,654 shares in 2009	(290)	(283)

Total El Paso Corporation stockholders equity	3,728	3,206
Noncontrolling interests	1,345	785
Total equity	5,073	3,991
Total liabilities and equity	$ 23,375	$ 22,505

See accompanying notes.

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

	Six Months Ended June 30,	
	2010	**2009**
Cash flows from operating activities		
Net income (loss)	$ 605	$ (857)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	460	453
Ceiling test charges	2	2,080
Deferred income tax expense (benefit)	270	(470)
Earnings from unconsolidated affiliates, adjusted for cash distributions	(104)	4
Other non-cash income items	(24)	26
Asset and liability changes	(223)	(63)
Net cash provided by operating activities	986	1,173
Cash flows from investing activities		
Capital expenditures	(1,594)	(1,363)
Cash paid for acquisitions, net of cash acquired	(10)	
Net proceeds from the sale of assets and investments	293	300
Other	21	(3)
Net cash used in investing activities	(1,290)	(1,066)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	965	983
Payments to retire long-term debt and other financing obligations	(1,060)	(1,214)
Net proceeds from issuance of noncontrolling interests	549	184
Dividends paid	(33)	(89)
Distributions to noncontrolling interest holders	(39)	(19)
Distributions to holders of preferred stock of subsidiary	(10)	
Other	4	(6)
Net cash provided by (used in) financing activities	376	(161)
Change in cash and cash equivalents	72	(54)
Cash and cash equivalents		
Beginning of period	635	1,024
End of period	$ 707	$ 970

See accompanying notes.

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning and end of period	$ 750	$ 750
Common stock:		
Balance at beginning of period	2,148	2,138
Other, net	10	9
Balance at end of period	2,158	2,147
Additional paid-in capital:		
Balance at beginning of period	4,501	4,612
Dividends	(33)	(89)
Other, including stock-based compensation	19	14
Balance at end of period	4,487	4,537
Accumulated deficit:		
Balance at beginning of period	(3,192)	(2,653)
Net income (loss) attributable to El Paso Corporation	545	(880)
Balance at end of period	(2,647)	(3,533)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(718)	(532)
Other comprehensive income (loss)	(12)	(118)
Balance at end of period	(730)	(650)
Treasury stock, at cost:		
Balance at beginning of period	(283)	(280)
Stock-based and other compensation	(7)	(1)
Balance at end of period	(290)	(281)
Total El Paso Corporation stockholders equity at end of period	3,728	2,970
Noncontrolling interests:		
Balance at beginning of period	785	561
Distributions paid to noncontrolling interests	(39)	(19)

Issuances of noncontrolling interests	549	184
Net income attributable to noncontrolling interests (Note 11)	50	23
Balance at end of period	1,345	749
Total equity at end of period	$ 5,073	$ 3,719

See accompanying notes.

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

	Quarters Ended June 30, 2010	Quarters Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income (loss)	$ 186	$ 100	$ 605	$ (857)
Pension and postretirement obligations:				
Reclassification of net actuarial losses during period (net of income taxes of $6 and $12 in 2010 and $4 and $8 in 2009)	11	7	24	14
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $23 and $25 in 2010 and $7 and $8 in 2009)	(37)	8	(40)	10
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 and $2 in 2010 and $34 and $80 in 2009)	2	(60)	4	(142)
Other comprehensive income (loss)	(24)	(45)	(12)	(118)
Comprehensive income (loss)	162	55	593	(975)
Comprehensive income attributable to noncontrolling interests	(29)	(11)	(60)	(23)
Comprehensive income (loss) attributable to El Paso Corporation	$ 133	$ 44	$ 533	$ (998)

See accompanying notes.

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 (GAAP). 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 June 30, 2010, and for the quarters and six months ended June 30, 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 an accounting standards update for financial asset transfers. Among other items, this update requires 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 this accounting standards update 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 an accounting standards update 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 this accounting standards update did not have a material impact on our financial statements. For a further discussion of our involvement with variable interest entities, see Note 13.

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2. Divestitures

During the second quarter of 2010, we completed the sale of certain of our interests in Mexican pipeline and compression assets for approximately $300 million and recorded a pretax gain of approximately $80 million. During 2009, we (i) sold our investment in the Argentina-to-Chile pipeline to our partners in the project for approximately $32 million, (ii) sold non-core natural gas producing properties located in our Central and Western regions for approximately $95 million, and (iii) sold our interest in the Porto Velho power generation facility in Brazil to our partner in the project for total consideration of $179 million, including $78 million in notes receivable. In the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of approximately $22 million.

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 and six months ended June 30, 2010 and 2009, we recorded the following ceiling test charges:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Full cost pool:				
U.S.	$	$	$	$ 2,031
Brazil				28
Egypt		12	2	21
Total	$	$ 12	$ 2	$ 2,080

During 2009, the calculation of these charges was based on spot commodity prices at the end of each quarter, 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 began using 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 and six months ended June 30 were as follows:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, except rates)			
Income tax (benefit) expense	$ 82	$ 66	$ 268	$ (460)
Effective tax rate	31%	40%	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, which are recorded in the period that the item occurs. 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.

For the quarter and six months ended June 30, 2010, our effective tax rate was impacted by the sale of certain of our interests in Mexican pipeline and compression assets and income attributable to nontaxable noncontrolling interests. Partially offsetting these items was $18 million of additional deferred income tax expense recorded in the first quarter 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. For the six months ended June 30, 2009, our effective tax rate was relatively consistent with the statutory rate and the customary relationship between our pretax accounting income and income tax expense. However, during the second quarter of 2009, our effective tax rate was primarily impacted by the sale and writedown of certain foreign investments for which there was no U.S. tax impact.

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5. Earnings Per Share

Quarters Ended June 30,

We calculated basic and diluted earnings (loss) per common share as follows for the quarters and six months ended June 30:

	2010		2009	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 157	$ 157	$ 89	$ 89
Preferred stock dividends of El Paso Corporation	(10)		(10)	(10)
Net income attributable to El Paso Corporation s common stockholders	$ 147	$ 157	$ 79	$ 79
Weighted average common shares outstanding	698	698	696	696
Effect of dilutive securities:				
Options and restricted stock		5		3
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	698	761	696	699
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.21	$ 0.21	$ 0.11	$ 0.11

Six Months Ended June 30,

	2010		2009	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ 545	$ 545	$ (880)	$ (880)
Preferred stock dividends of El Paso Corporation	(19)		(19)	(19)
Interest on trust preferred securities		5		
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 526	$ 550	$ (899)	$ (899)
Weighted average common shares outstanding	697	697	695	695
Effect of dilutive securities:				
Options and restricted stock		5		
Convertible preferred stock		58		
Trust preferred securities		8		
Weighted average common shares outstanding and dilutive securities	697	768	695	695

Basic and diluted earnings (loss) per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.75	$ 0.72	$ (1.29)	$ (1.29)

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 and six months ended June 30, 2010, and the quarter ended June 30, 2009, certain of our employee stock options were antidilutive. Additionally, our trust preferred securities were antidilutive for the quarters ended June 30, 2010 and 2009 and our convertible preferred stock was antidilutive for the quarter ended June 30, 2009. For the six months ended June 30, 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.

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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.

During the quarter and six months ended June 30, 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 June 30, 2010 and December 31, 2009:

	June 30, 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	$	$ 292	$	$ 292	$	$ 169	$	$ 169
Other natural gas derivatives		57	18	75		106	21	127
Power-related derivatives			25	25			37	37
Interest rate derivatives		11		11		11		11
Marketable securities invested in non-qualified compensation plans	21			21	20			20

Total assets	21	360	43	424	20	286	58	364
Liabilities								
Commodity-based derivatives								
Production-related natural gas and oil derivatives		(19)		(19)		(42)		(42)
Other natural gas derivatives		(92)	(109)	(201)		(153)	(133)	(286)
Power-related derivatives			(373)	(373)			(386)	(386)
Interest rate derivatives		(62)		(62)		(17)		(17)
Other			(12)	(12)			(31)	(31)
Total liabilities		(173)	(494)	(667)		(212)	(550)	(762)
Total	$ 21	$ 187	$ (451)	$ (243)	$ 20	$ 74	$ (492)	$ (398)

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 nine financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

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The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarters and six months ended June 30, 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)		
Quarter Ended June 30, 2010					
Assets	$ 42	$ 1	$	$	$ 43
Liabilities	(490)	(44)	3	37	(494)
Total	$ (448)	$ (43)	$ 3	$ 37	$ (451)
Six Months Ended June 30, 2010					
Assets	$ 58	$ (14)	$	$ (1)	$ 43
Liabilities	(550)	(11)	(1)	68	(494)
Total	$ (492)	$ (25)	$ (1)	$ 67	$ (451)

(1) Includes approximately $43 million and $25 million of net losses that had not been realized through settlements for the quarter and six months ended June 30, 2010. These losses are primarily based on additional market information on these contracts.

(2) Includes less than $1 million of net losses that had not been

realized through settlements for the quarter and six months ended June 30, 2010.

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

	June 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In millions)		
Financing obligations	$ 13,794	$ 14,183	$ 13,868	$ 14,151
Marketable securities invested in non-qualified compensation plans	21	21	20	20
Commodity-based derivatives	(201)	(201)	(381)	(381)
Interest rate derivatives	(51)	(51)	(6)	(6)
Other derivatives	(12)	(12)	(31)	(31)
Other	17	17	17	17

As of June 30, 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.

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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 June 30, 2010 and December 31, 2009, cash collateral held was not material.

	Fair Value of Derivative Assets		Fair Value of Derivative Liabilities	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
	(In millions)			
Derivatives Designated as Hedges:				
Interest rate derivatives				
Cash flow hedges	$	$ 1	$ (62)	$ (17)
Fair value hedges	11	10		
Total derivatives designated as hedges	11	11	(62)	(17)
Derivatives not Designated as Hedges:				
Commodity-based derivatives				
Production-related	316	239	(43)	(112)
Other natural gas	311	519	(437)	(678)
Power-related	37	57	(385)	(406)
Total commodity-based derivatives	664	815	(865)	(1,196)
Interest rate derivatives	11	10	(11)	(10)
Total derivatives not designated as hedges	675	825	(876)	(1,206)
Impact of master netting arrangements	(283)	(492)	283	492
Total assets (liabilities) from price risk management activities	403	344	(655)	(731)
Other derivatives			(12)	(31)
Total derivatives	$ 403	$ 344	$ (667)	$ (762)

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 June 30, 2010 and December 31, 2009, we have production-related derivatives on 253 TBtu and 313 TBtu of natural gas and 4,382 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 June 30, 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. During the third quarter of 2010, we entered into positions that eliminate a portion of the risk related to the locational price differences on these contracts.

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Listed below are the impacts of our commodity-based derivatives to our income statement and statement of comprehensive income for the quarters and six months ended June 30:

	2010		2009	
	Operating Revenues	Other Comprehensive Income	Operating Revenues	Other Comprehensive (Loss)
	(In millions)			
Quarters ended June 30,				
Production-related derivatives[1]	$ 31	$ 3	$ 55	$ (99)
Other natural gas and power derivatives not designated as hedges	(43)		18	
Total commodity-based derivatives[2]	$ (12)	$ 3	$ 73	$ (99)
Six months ended June 30,				
Production-related derivatives[1]	$ 284	$ 6	$ 449	$ (227)
Other natural gas and power derivatives not designated as hedges	(26)		73	
Total commodity-based derivatives[2]	$ 258	$ 6	$ 522	$ (227)

(1) We reclassified $3 million and $6 million of accumulated other comprehensive loss for the quarter and six months ended June 30, 2010 and $99 million and $227 million of accumulated other comprehensive income for the quarter and six months ended June 30, 2009 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 $3 million and $26 million of gains for the quarters ended June 30, 2010 and 2009 and $1 million of losses and $25 million of gains for the six months ended June 30, 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 June 30, 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 $1.3 billion and $169 million of debt from a floating LIBOR interest rate to a fixed interest rate. Approximately $1.1 billion of the debt hedged as of June 30, 2010, relates to Ruby debt obligations. These swaps begin accruing interest on July 1, 2011 and have termination dates ranging from June 2013 to June 2017 which correspond to the principal outstanding on the Ruby debt over the term of these swaps. For a further discussion of our Ruby hedges, see Note 8.

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 June 30, 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 decreased our other comprehensive income by $45 million and $46 million for the quarter and six months ended June 30, 2010 and increased our other comprehensive income by $5 million and $8 million for the quarter and six months ended June 30, 2009. Our interest rate derivatives did not have a significant impact to our interest expense during the quarter and six months ended June 30, 2010 and 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.

Cross-Currency Derivatives

During the second quarter of 2009, our Euro-denominated debt matured and we settled all of our related cross-currency swaps, which were designated as fair value hedges of this debt. During the quarter and six months ended June 30, 2009, these swaps resulted in an increase to our interest expense of approximately $1 million and $3 million and an increase of $3 million and a decrease of $21 million to our other income due to changing interest and foreign currency rates during the first half of 2009.

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8. Debt, Other Financing Obligations and Other Credit Facilities

	June 30, 2010	December 31, 2009
	(In millions)	
Short-term financing obligations, including current maturities	$ 711	$ 477
Long-term financing obligations	13,083	13,391
Total	$ 13,794	$ 13,868

Changes in Financing Obligations. During the six months ended June 30, 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[(1)]	13.00%	188	187
El Paso Pipeline Partners Operating Company, L.L.C. notes due 2020	6.50%	535	528
El Paso revolving credit facility	variable	193	193
El Paso Pipeline Partners L.P. (EPB) revolving credit facility	variable	38	38
Increases through June 30, 2010		$ 973	$ 965
Repayments, repurchases, and other			
El Paso Exploration and Production Company revolving credit facility	variable	$ (469)	$ (469)
El Paso revolving credit facility	variable	(393)	(393)
EPB revolving credit facility	variable	(38)	(38)
El Paso notes due 2010	7.75% and 7.80%	(149)	(149)
Other	various	2	(11)
Decreases through June 30, 2010		$ (1,047)	$ (1,060)

(1) Initial interest rate of 7.00% increased to 13.00% effective April 1, 2010.

Loan commitment converted to Ruby preferred equity in August 2010.

Credit Facilities. We have various credit facilities in place which allow us to borrow funds or issue letters of credit. As of June 30, 2010, we had total available capacity of approximately $2.2 billion under these facilities (not including capacity available under the EPB $750 million revolving credit facility and all project financings).

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 facilities of our exploration and production subsidiary are 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 June 30, 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 June 30, 2010, we had total outstanding letters of credit issued under all of our facilities of approximately $0.9 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 entered into a seven-year amortizing $1.5 billion financing facility for our Ruby pipeline project that requires principal payments at various dates through June 2017. In August 2010, we made an initial draw of approximately $250 million on the facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance $700 million of the facility by the end of year four. If we do not refinance $700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that begin in July 2011 and convert the floating LIBOR interest rate to fixed interest rates on approximately $1.1 billion of total borrowings under this agreement. For a further discussion of these swaps, see Note 7. We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us.

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 all of the claims. The dismissal of the case is subject to appeal.

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 settled, 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 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 executed agreements to settle another 26 cases, which will be substantially funded by insurance. Following dismissal of these settled cases, we will have nine lawsuits that remain. It is likely that our insurers will assert denial of coverage on the six most-recently filed cases. Our costs and legal exposure related to the remaining lawsuits are not currently determinable.

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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 June 30, 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

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 August 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 was completed in June 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 June 30, 2010, we had accrued approximately $178 million for environmental matters, which has not been reduced by $22 million for amounts to be paid directly under government sponsored programs or through contractual arrangements with third parties. Our accrual includes approximately $174 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $4 million for related environmental legal costs. Of the $178 million accrual, $12 million was reserved for facilities we currently operate and $166 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 $178 million to approximately $380 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:

	June 30, 2010	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 12	$ 19
Non-operating	151	323
Superfund	15	38
Total	$ 178	$ 380

Below is a reconciliation of our accrued liability from January 1, 2010 to June 30, 2010 (in millions):

Balance as of January 1, 2010	$ 189
Additions/adjustments for remediation activities	6
Payments for remediation activities	(17)
Balance as of June 30, 2010	$ 178

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

For the remainder of 2010, we estimate that our total remediation expenditures will be approximately $29 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 June 30, 2010, we have recorded obligations of $24 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 June 30, 2010, TGP has refunded approximately $39 million to their customers.

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10. Retirement Benefits

Net Benefit Cost. The components of net benefit cost for our pension and postretirement benefit plans for the quarters and six months ended June 30, are as follows:

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009	2010	2009	2010	2009
	(In millions)							
Service cost	$ 4	$ 4	$	$	$ 9	$ 8	$	$
Interest cost	29	30	9	10	57	60	17	19
Expected return on plan assets	(40)	(43)	(4)	(3)	(79)	(86)	(7)	(6)
Amortization of net actuarial loss (gain)	18	11	(1)		37	22	(2)	
Amortization of prior service cost	1				1			
Net benefit cost	$ 12	$ 2	$ 4	$ 7	$ 25	$ 4	$ 8	$ 13

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 June 30, 2010	$ 14	$ 19
Amount paid in July 2010	$ 7	$ 9
Declared in July 2010:		
Date of declaration	July 21, 2010	July 21, 2010
Payable to shareholders on record	September 3, 2010	September 15, 2010
Date payable	October 1, 2010	October 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. During the first half of 2010, we contributed a 51 percent interest in Southern LNG Company, L.L.C. (SLNG), which owns the Elba Island LNG receiving terminal, a 51 percent interest in El Paso Elba Express Company, L.L.C. (Elba Express), which owns the Elba Express Pipeline, and an additional 20 percent interest in Southern Natural Gas Company (SNG) to EPB in exchange for $1.3 billion which included cash and 5.3 million EPB common units. EPB raised the funds for the acquisitions primarily through the issuance of 21.4 million common units, which increased our noncontrolling interests, and the proceeds from debt offerings. As of June 30, 2010, our ownership interest in EPB is 59 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 six months ended June 30, 2010 and 2009, EPB made cash distributions of $39 million and $19 million to its non-affiliated common unitholders. We have recorded net income attributable to noncontrolling interest holders of

$24 million and $11 million during the quarters ended June 30, 2010 and 2009, and $50 million and $23 million during the six months ended June 30, 2010 and 2009, 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 Investment 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. Preferred dividends were paid associated with GIP s preferred interest of $5 million and $10 million for the quarter and six months ended June 30, 2010 and are 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 June 30, 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 June 30, 2010, we conducted our activities primarily through eight wholly or majority owned interstate pipeline systems and equity interests in two transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in three underground natural gas storage facilities and two LNG 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, our recently formed midstream business, our remaining power operations, and 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 June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Segment EBIT	$ 497	$ 398	$ 1,325	$ (839)
Corporate and Other	26	10	15	7
Consolidated EBIT	523	408	1,340	(832)
Interest and debt expense	(284)	(253)	(527)	(508)
Income tax benefit (expense)	(82)	(66)	(268)	460
Net income (loss) attributable to El Paso Corporation	157	89	545	(880)

Net income attributable to noncontrolling interests	29	11	60	23
Net income (loss)	$ 186	$ 100	$ 605	$ (857)

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The following table reflects our segment results for the quarters and six months ended June 30:

	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate and Other(1)	Total
			(In millions)		

(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 June 30, 2010 and 2009, we recorded an intersegment revenue elimination of $6 million and $2 million in the "Corporate and Other" column to remove intersegment transactions.

(2) Revenues from external customers include gains of $31 million and $55 million for the quarters ended June 30,

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.

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

	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate and Other(1)	Total
			(In millions)		
Six Months Ended June 30, 2010					
Revenue from external customers	$ 1,392	$ 626(2)	$ 382	$ 19	$ 2,419
Intersegment revenue	25	390(2)	(411)	(4)	
Operation and maintenance	379	188	3	14	584
Ceiling test charges		2			2
Depreciation, depletion and amortization	216	235		9	460
Earnings (losses) from unconsolidated affiliates	129(3)	(1)		11	139
EBIT	864	493	(32)	15	1,340
Six Months Ended June 30, 2009					
Revenue from external customers	$ 1,360	$ 759(2)	$ 336	$ 2	$ 2,457
Intersegment revenue	23	250(2)	(268)	(5)	
Operation and maintenance	378	199	5	(18)	564

Ceiling test charges		2,080			2,080
Depreciation, depletion and amortization	206	241		6	453
Earnings (losses) from unconsolidated affiliates	46	(22)		7	31
EBIT	723	(1,624)	62	7	(832)

(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 six months ended June 30, 2010 and 2009, we recorded an intersegment revenue elimination of $8 million and $5 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $284 million and $449 million for the six months ended June 30, 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.

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

Total assets by segment are presented below:

	June 30, 2010	December 31, 2009
	(In millions)	
Pipelines	$ 17,724	$ 17,324
Exploration and Production	4,251	4,025
Marketing	272	345
Total segment assets	22,247	21,694
Corporate and Other	1,128	811
Total consolidated assets	$ 23,375	$ 22,505

13. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby. We consolidate our investment in Ruby Pipeline Holding Company, L.L.C. (Ruby), a variable interest entity that owns our Ruby pipeline project, as its primary beneficiary. In July 2009, we entered into an agreement with GIP whereby they agreed to invest up to $700 million and acquire a 50 percent equity interest in Ruby subject to certain conditions. As part of this agreement, GIP contributed $145 million in exchange for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains and entered into a loan commitment to provide $405 million of project funding to Ruby, all of which has been borrowed as of June 30, 2010. Our initial interest rate on the loan commitment was 7 percent, which increased to 13 percent on April 1, 2010. The agreement also stipulates that GIP provide an additional $150 million of preferred equity contributions to Ruby upon receipt of all FERC approvals and securing approximately $1.4 billion of third party financing.

In the second quarter of 2010, we received certification from the FERC authorizing the project and entered into a $1.5 billion third party project financing facility. In July 2010, we received a Bureau of Land Management (BLM) right-of way grant, received final approval from the FERC and began construction of the Ruby pipeline. An environmental group has filed an appeal of certain approvals and actions of the BLM and the U.S. Fish and Wildlife Service for the project. We are currently unable to predict what action, if any, that the court will take in response to the filing.

In August 2010, we made an initial draw of approximately $250 million on the $1.5 billion facility, the $405 million funded under GIP s loan commitment converted to a convertible preferred equity interest in Ruby, and GIP provided an additional $120 million contribution for a convertible preferred equity interest in Ruby. The convertible preferred equity interest earns a 13 percent preferred return until it is converted to common equity in Ruby.

Cheyenne Plains is also a variable interest entity we consolidate as its primary beneficiary. GIP will hold its interest in Cheyenne Plains until certain conditions are satisfied, including placing the Ruby pipeline project in service. GIP has the right to convert its preferred equity 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 November 2011, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining 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 and six months ended June 30, 2009, we received $227 million and $479 million of cash related to the sale of the senior interests, collected $217 million and $489 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 on our balance sheet. In January 2010, we terminated these accounts receivable sales programs and paid $90 million to acquire the senior interests. We reflected the cash flows related to the accounts receivable sold under this program, changes in our retained subordinated interests, and cash paid to terminate the programs, as operating cash flows on our statement of cash flows.

In the first quarter of 2010, we entered into new accounts receivable sales programs to continue to sell accounts receivable to the third party financial institution that qualify for sale accounting under the updated accounting standards related to financial asset transfers, and to include an additional pipeline subsidiary s accounts receivable in the program. Under these programs, several of our pipeline subsidiaries sell receivables in their entirety to the third-party financial institution (through wholly-owned special purpose entities). As of June 30, 2010, the third-party financial institution held $194 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 quarter and six months ended June 30, 2010, we received $331 million and $786 million of cash up front from the sale of the receivables and received an additional $243 million and $480 million of cash upon the collection of the underlying receivables. As of June 30, 2010, we had not collected approximately $85 million related to our accounts receivable sales, which is reflected as other accounts receivable on our balance sheet (and was initially recorded at an amount which approximates its fair value as a Level 2 measurement). We recognized a loss of less than $1 million and $1 million on our accounts receivable sales during the quarter and six months ended June 30, 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 on our statement of cash flows.

Under both the prior and current accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements as well as the fees earned were not material to our financial statements for the periods ended June 30, 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.

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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 on our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments, gains and losses on divestitures and other adjustments recorded by us. 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			
			Quarters Ended		Six Months Ended	
	June 30, 2010	December 31, 2009	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Four Star [1]	$ 423	$ 450	$ (1)	$ (12)	$ (1)	$ (22)
Citrus	669	630	25	20	40	34
Gulf LNG[2]	263	285		(1)		(1)
Gasoductos de Chihuahua[3]		184	82	6	88	12
Bolivia-to-Brazil Pipeline	106	105	4	(5)	9	(1)
Other	68	64	1	4	3	9
Total	$ 1,529	$ 1,718	$ 111	$ 12	$ 139	$ 31

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $9 million and $13 million for the quarters ended June 30, 2010 and 2009 and $19 million and $25 million for the six months ended June 30, 2010 and 2009.

(2) As of June 30, 2010 and December 31,

2009, we had outstanding advances and receivables of $71 million and $56 million, not included above, related to our investment in Gulf LNG.

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$ 128	$ 135	$ 260	$ 258
Operating expenses	65	69	138	137
Net income	41	24	79	59

We received distributions and dividends from our unconsolidated affiliates of $21 million and $24 million for the quarters ended June 30, 2010 and 2009 and $36 million for each of the six months ended June 30, 2010 and 2009. Included in these amounts are returns of capital of $1 million or less for the quarters and six months ended June 30, 2010 and 2009. Our revenues and charges with unconsolidated affiliates were not material during the quarters and six months ended June 30, 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 lawsuits to collect amounts due to us (approximately $64 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 $69 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 defending us with respect to this assessment pursuant to its indemnity duty under the relevant contracts. The resolution of these lawsuits 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 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.

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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 first six months of 2010, both our pipeline and exploration and production operations provided a strong base of earnings and operating cash flow. In our pipeline business our rates have remained relatively stable. Approximately 80 percent of our pipeline revenues are collected in the form of demand or reservation charges, which are not dependent upon commodity prices or throughput levels. Currently, only one of our pipelines has an outstanding rate case pending before the FERC; however certain of our other pipelines have projected upcoming rate actions with anticipated effective dates from 2011 through 2014. In our exploration and production business, during the first six months of 2010, we benefited from strong domestic natural gas and oil volumes and our natural gas derivative contracts. Year-to-date combined production volumes were down slightly from 2009, but second quarter 2010 production volumes were up quarter over quarter. During 2010, we also entered into additional hedges on our anticipated oil and natural gas production and have financial derivative contracts in place related to our remaining 2010 and 2011 production that provide downside price protection while still allowing for potential upside. As of June 30, 2010, we had 89 TBtu of natural gas hedges with an average floor price of $6.12 per MMBtu, 61 TBtu of natural gas hedges with an average ceiling price of $6.27 per MMBtu and 2,374 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. 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.

We have made significant progress on our 2010 objectives, including meeting our 2010 planned funding requirements and are currently addressing our 2011 funding needs. During 2010, we completed our $1.5 billion project financing facility for the Ruby pipeline project, received a BLM right-of way grant, received final approval from the FERC and began construction of the Ruby pipeline project. For additional information on our Ruby pipeline project, see *Liquidity and Capital Resources*. We also received $1.2 billion in cash in conjunction with contributing ownership interests in SLNG, Elba Express and SNG to our master limited partnership (MLP) and sold certain of 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 percent of the anticipated construction cost of our Ruby pipeline project) and approximately $1.1 billion related to our exploration and production business. Our pipelines 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 six months of 2010. Our exploration and production business will remain focused on targeting capital towards more unconventional resource plays, with more than half of our 2010 domestic capital program targeted for the Haynesville, Altamont and Eagle Ford areas. 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 approximately $100 million of debt that will mature. This does not include approximately $405 million of Ruby debt that converted to Ruby preferred equity in August 2010.

As of June 30, 2010, we had approximately $2.9 billion of available liquidity (exclusive of cash and 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.

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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, our recently formed midstream business, our remaining power operations, and 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 and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Segment				
Pipelines	$ 443	$ 327	$ 864	$ 723
Exploration and Production	103	61	493	(1,624)
Marketing	(49)	10	(32)	62
Segment EBIT	497	398	1,325	(839)
Corporate and Other	26	10	15	7
Consolidated EBIT	523	408	1,340	(832)
Interest and debt expense	(284)	(253)	(527)	(508)
Income tax benefit (expense)	(82)	(66)	(268)	460
Net income (loss) attributable to El Paso Corporation	157	89	545	(880)
Net income attributable to noncontrolling interests	29	11	60	23
Net income (loss)	$ 186	$ 100	$ 605	$ (857)

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Pipelines Segment

Overview and Operating Results. During the first six months of 2010, we continued to deliver strong operational and financial performance across all our pipelines. Our EBIT for the quarter and six months ended June 30, 2010 increased 35 percent and 20 percent from the same periods in 2009, and includes the impact of an $80 million gain recorded in the second quarter of 2010 on the sale of certain of our interests in Mexican pipeline and compression assets. During the first six months of 2010, we also benefited from several expansion projects placed in service in 2010 and 2009 and other income associated with the allowance for funds used during construction (AFUDC) primarily on our Ruby pipeline project. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the quarters and six months ended June 30, 2010 and 2009, or that could potentially impact EBIT in future periods.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions, except for volumes)			
Operating revenues	$ 680	$ 650	$ 1,417	$ 1,383
Operating expenses	(370)	(365)	(726)	(731)
Operating income	310	285	691	652
Other income, net	162	53	233	94
EBIT before adjustment for noncontrolling interests	472	338	924	746
Net income attributable to noncontrolling interests	(29)	(11)	(60)	(23)
EBIT	$ 443	$ 327	$ 864	$ 723
Throughput volumes (BBtu/d)[1]	17,150	17,929	17,968	18,817

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

	Quarter Ended June 30, 2010 Variance				Six Months Ended June 30, 2010 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 51	$ (9)	$ 26	$ 68	$ 78	$ (15)	$ 62	$ 125

Reservation and usage revenues	(5)			(5)	(2)			(2)
Gas not used in operations and revaluations	(15)	6		(9)	(44)	19		(25)
Operating and general and administrative expenses		3		3		6		6
Gain/loss on assets and investments			80	80		(10)	80	70
Other[1]	(1)	(5)	3	(3)	2	5	(3)	4
Total impact on EBIT before adjustment for noncontrolling interests	30	(5)	109	134	34	5	139	178
Net income attributable to noncontrolling interests			(18)	(18)			(37)	(37)
Total impact on EBIT	$ 30	$ (5)	$ 91	$ 116	$ 34	$ 5	$ 102	$ 141

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

Expansions. During the first six months 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, the Wyoming Interstate (WIC) Piceance Lateral expansion, and Phase A of the SLNG Elba Expansion III vaporization facilities and Elba Express Pipeline expansions. In July 2010, we placed the SLNG Elba Expansion III storage tank in service and currently expect to place the Colorado Interstate Gas (CIG) Raton 2010 project in service by the end of 2010.

We capitalize a carrying cost (an allowance for funds used during construction) on debt and equity funds related to our construction of long-lived assets. During the quarter and six months ended June 30 2010, we benefited from an increase in other income of approximately $26 million and $62 million associated with the equity portion of AFUDC on our expansion projects. This increase is primarily due to our Ruby pipeline project.

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

Ruby Pipeline Project. In the second quarter of 2010, we received certification from the FERC authorizing the project. In July 2010, we received a BLM right-of-way grant, received final approval from the FERC and began construction of the pipeline. Although we will need additional authorizations from the FERC to construct in certain areas of the route, we expect to receive them as we satisfy various regulatory conditions and requirements, such as implementing required historic resource protection plans. An environmental group has filed a petition with a federal court of appeals objecting to certain approvals and actions of the BLM and the U.S. Fish & Wildlife Service related to the project. Although we are able to continue construction of the pipeline pending the federal court of appeals review of the petition, we are unable to predict what action, if any, that the court will take in response to the filing.

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

WIC System Expansion. During 2010, WIC received certificate authorization from the FERC to construct the WIC Expansion project, which will install three miles of pipeline and reconfigure one compressor at the Wamsutter station. We anticipate that both portions of the WIC Expansion project will be placed in service in the fourth quarter of 2010.

TGP Northeast Upgrade Project. In February 2010, TGP entered into precedent agreements with two shippers to provide 620 MMcf/d of additional firm transportation service from receipt points in the Marcellus Shale basin to an interconnect in New Jersey.

TGP 300 Line Expansion. During 2010, the FERC issued a favorable environmental assessment and TGP received certificate authorization from the FERC to construct the expansion. In June 2010, we commenced construction on our compression facilities related to this project.

TGP Northeast Supply Diversification Project. During 2010, we entered into precedent agreements with three shippers to provide up to approximately 250 MMcf/d of additional firm transportation service from receipt points in the Marcellus shale basin to delivery points in the New York and New England markets. Total estimated cost of this project is less than $100 million. Subject to FERC and other approvals, the project is expected to commence construction in the first half of 2012 and is anticipated to be placed in service on November 1, 2012.

Reservation and Usage Revenues. During the quarter and six months ended June 30, 2010, our reservation and usage revenues were unfavorably impacted by lower rates and throughput on our EPNG system and lower usage on our TGP system which were partially offset by higher tariff rates on our SNG system effective September 1, 2009 pursuant to its rate case settlement. During 2010, EPNG experienced 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. During the quarter and six months ended June 30, 2010, throughput volumes on our TGP system increased by six percent and two percent compared to the same periods in 2009. However, usage revenue was lower because TGP s long-haul transports decreased due to a shift in receipts from the Gulf Coast region to the Rockies Express Pipeline (REX) interconnect and the Marcellus shale basin, which is short-haul transportation and subject to lower rates. We believe our recently announced TGP Northeast Supply Diversification project will expand our presence from Marcellus to the New York and New England markets.

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Although approximately 80 percent of our pipeline revenues are derived from reservation charges, lower throughput can affect our level of revenues from commodity charges, such as with our TGP system, or be an indication of the risks we may face when seeking to recontract or renew any of our existing firm transportation contracts. Continuing negative economic impacts on demand, as well as adverse shifting of sources of supply, could negatively impact basis differentials and our ability to renew firm transportation contracts that are expiring on our 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 provide an opportunity to recover our prudently incurred costs.

Gas Not Used in Operations and Revaluations. During the quarter and six months ended June 30, 2010 compared with the same periods in 2009, our EBIT was negatively impacted primarily by lower commodity volumes and realized prices on operational sales and unfavorable revaluations, partially offset by positive impacts due to lower electric compression utilization and higher condensate sales. 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 and six months ended June 30, 2010, our operating and general and administrative expenses were lower compared to the same periods in 2009 primarily due to the impact of cost savings initiatives in 2010.

Gain/loss on Assets and Investments. During the second quarter of 2010, we recorded a gain of approximately $80 million on the sale of our interests in certain Mexican pipeline and compression assets. In addition, 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.

Net Income Attributable to Noncontrolling Interests. During the quarter and six months ended June 30, 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, (ii) our contribution of an additional 18 percent interest in CIG to our MLP in July 2009 and (iii) our contribution of a 51 percent interest in SLNG and Elba Express to our MLP in March 2010. Additionally, in late June 2010, our MLP issued additional public common units and we contributed an additional 20 percent interest in SNG to our MLP. As of June 30, 2010, we owned 59 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 2014.

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

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 August 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 was completed in June 2010 and the outcome is not currently determinable.

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Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance of this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. 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 changes in commodity prices and industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating, and capital costs. Additionally we may be impacted by the effect of hurricanes and other weather events, or the effects of domestic or international regulatory or other actions in response to events outside of our control (e.g. oil spills). We attempt to mitigate certain of these risks through actions, such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Periods Ended June 30, 2010

Production. Our average daily production for the six months ended June 30, 2010 was 784 MMcfe/d, including 62 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the periods ended June 30:

	2010	2009
	MMcfe/d	
United States		
Central	319	249
Western	156	163
Gulf Coast	216	296
International		
Brazil	31	9
Total Consolidated	722	717
Four Star	62	73
Total Combined	784	790

In the first six months of 2010, production volumes increased in our Central division as a result of our successful Arklatex drilling programs, including the Haynesville Shale. As of June 30, 2010, we had 36 operated producing wells in the Haynesville Shale compared to 20 operated producing wells at December 31, 2009. In our Western division, production volumes slightly 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 this division, our focus since 2009 has been to increase our Eagle Ford Shale acreage, where we hold approximately 165,000 net acres as of June 30, 2010 and have completed five successful well tests. In Brazil, our production volumes increased due to production from our Camarupim Field.

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2010 Drilling Results

Our drilling results for the six months ended June 30, 2010 are as follows:

Domestic. We achieved a 97 percent success rate on 139 gross wells drilled. By division, these results were as follows:

	Success Rate	Gross Wells Drilled
Central	98%	114
Western	100%	12
Gulf Coast	85%	13

International

Brazil. In Brazil, our activities are primarily in the Camamu and Espirito Santo Basins. During the first six months of 2010, we continued to seek 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 in the fourth quarter of 2010. During the second quarter of 2010, we participated with Petrobras in drilling an additional exploratory well in the ES-5 block. Hydrocarbons were found in the well and we are now evaluating results. As of June 30, 2010, we have total capitalized costs in Brazil of approximately $357 million, of which $175 million are unevaluated capitalized costs.

Egypt. During the first six months of 2010, we participated in drilling our fourth and fifth exploratory wells in the South Alamein block. The wells encountered oil shows but were temporarily plugged as we continue to evaluate the results. In our Tanta block, we spud our first exploratory well in July 2010. In our South Mariut block, we relinquished approximately 30 percent of our acreage resulting in a $2 million non-cash charge during the first quarter of 2010. Additionally, we relinquished the South Feiran concession in March 2010. As of June 30, 2010, we have total capitalized costs in Egypt of approximately $81 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 six months ended June 30, 2010, cash operating costs per unit decreased to $1.83/Mcfe as compared to $1.85/Mcfe during the same period in 2009.

Capital Expenditures. Our total natural gas and oil capital expenditures were $573 million for the six months ended June 30, 2010, of which $516 million were domestic capital expenditures.

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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 $1.0 billion on our domestic program and approximately $0.1 billion in Brazil and Egypt;

- Average daily production volumes for the year of approximately 760 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 30 MMcfe/d and 35 MMcfe/d in 2010;

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

- 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.

The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of June 30, 2010.

	Fixed Price Swaps(1)		**Floors(1)**		**Ceilings(1)**		**Basis Swaps(1)(2)**							
											Western		**Central**	
							Texas Gulf Coast		**Raton**		**Rockies**		**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	44	$ 5.79	45	$ 6.43	17	$ 7.50	24	$ (0.40)	10	$ (0.78)	5	$ (1.93)	5	$ (0.74)
2011	23	$ 6.01	131	$ 6.00	131	$ 8.76	33	$ (0.13)	22	$ (0.25)				
2012	10	$ 5.56												
Oil														
2010	1,546	$ 77.02	828	$ 75.00	828	$ 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.

During the six months ended June 30, 2010, we also entered into offsetting fixed price swap transactions that effectively lock in a cash settlement of $8.78 above market prices on 2,500 MMbls of our anticipated 2011 crude oil production.

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 June 30, 2010, we have fuel oil swaps that effectively lock in a price of approximately $4.00 per MMBtu on approximately 4 TBtu of projected Brazilian natural gas production in 2010.

During the third quarter of 2010, we terminated 29.2 TBtu of our 2011 natural gas collars and entered into fixed price swaps at $5.00 per MMBtu on 0.9 TBtu of our anticipated fourth quarter 2010 natural gas production, fixed price swaps at $6.00 per MMBtu on 33.4 TBtu of our anticipated 2011 natural gas production, and fixed price swaps at $6.50 per MMBtu on 31.4 TBtu of our anticipated 2012 natural gas production. We also entered into calls at $95.00 per barrel on 1,098 MBbls of our anticipated 2012 oil production and on 1,095 MBbls of our anticipated 2013 oil production.

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Operating Results and Variance Analysis

The information below provides the financial results and an analysis of significant variances in these results during the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Physical sales				
Natural gas	$ 228	$ 176	$ 516	$ 428
Oil, condensate and NGL	105	68	198	114
Total physical sales	333	244	714	542
Realized and unrealized gains on financial derivatives	31	55	284	449
Other revenues	5	10	18	18
Total operating revenues	369	309	1,016	1,009
Operating expenses				
Cost of products	5	8	15	13
Transportation costs	18	15	36	35
Production costs	64	54	133	132
Depreciation, depletion and amortization	128	91	235	241
General and administrative expenses	47	51	96	101
Ceiling test charges		12	2	2,080
Other	5	2	9	6
Total operating expenses	267	233	526	2,608
Operating income (loss)	102	76	490	(1,599)
Other income (expense)[1]	1	(15)	3	(25)
EBIT	$ 103	$ 61	$ 493	$ (1,624)

(1) 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.

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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.

	Quarters Ended June 30,			Six Months Ended June 30,		
	2010	**2009**	**Percent Variance**	**2010**	**2009**	**Percent Variance**
Volumes						
Natural gas (MMcf)						
Consolidated volumes	56,361	55,060	2%	112,508	111,922	1%
Unconsolidated affiliate volumes	4,144	5,043	(18)%	8,358	9,903	(16)%
Oil, condensate and NGL (MBbls)						
Consolidated volumes	1,632	1,483	10%	3,034	2,960	2%
Unconsolidated affiliate volumes	231	283	(18)%	477	559	(15)%
Equivalent volumes						
Consolidated MMcfe	66,154	63,957	3%	130,711	129,680	1%
Unconsolidated affiliate MMcfe	5,529	6,743	(18)%	11,219	13,258	(15)%
Total combined MMcfe	71,683	70,700	1%	141,930	142,938	(1)%
Consolidated MMcfe/d	727	703	3%	722	717	1%
Unconsolidated affiliate MMcfe/d	61	74	(18)%	62	73	(15)%
Total combined MMcfe/d	788	777	1%	784	790	(1)%
Consolidated prices and costs per unit						
Natural gas ($/Mcf)						
Average realized price on physical sales	$ 4.05	$ 3.21	26%	$ 4.59	$ 3.82	20%
Average realized price, including financial derivative settlements (1)	$ 5.86	$ 7.07	(17)%	$ 5.95	$ 7.80	(24)%
Average transportation costs	$ 0.31	$ 0.25	24%	$ 0.30	$ 0.30	%
Oil, condensate and NGL ($/Bbl)						
Average realized price on physical sales	$ 64.07	$ 45.54	41%	$ 65.09	$ 38.43	69%
Average realized price, including financial derivative settlements(1)(2)	$ 63.69	$ 75.21	(15)%	$ 64.32	$ 72.68	(12)%
Average transportation costs	$ 0.66	$ 0.84	(21)%	$ 0.74	$ 0.88	(16)%
Production costs and other cash operating costs ($/Mcfe)	$ 0.67	$ 0.61	10%	$ 0.71	$ 0.75	(5)%

Average lease operating expenses									
Average production taxes[3]		0.30		0.23	30%		0.31		0.26	19%
Total production costs	$	0.97	$	0.84	15%	$	1.02	$	1.01	1%
Average general and administrative expenses		0.72		0.79	(9)%		0.74		0.78	(5)%
Average taxes, other than production and income taxes		0.08		0.05	66%		0.07		0.06	17%
Total cash operating costs	$	1.77	$	1.68	5%	$	1.83	$	1.85	(1)%
Depreciation, depletion and amortization ($/Mcfe)[4]	$	1.92	$	1.43	34%	$	1.79	$	1.86	(4)%

(1) Premiums paid in 2009 related to natural gas derivatives settled during the quarter and six months ended June 30, 2010 were $48 million and $100 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 $0.85/Mcf and $0.89/Mcf for the quarter and six months ended June 30, 2010. We had no premiums related to natural gas derivatives settled during

the quarter and six months ended June 30, 2009, or related to oil derivatives settled during the quarters and six months ended June 30, 2010 and 2009.

(2) Amounts for the quarter and six months ended June 30, 2009, include approximately \$50 million and \$87 million related to \$186 million of cash received in the first quarter of 2009 for the early settlement of oil derivative contracts originally scheduled to mature throughout 2009.

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

(4) Includes \$0.07 per Mcfe for each of the quarters ended June 30, 2010 and 2009 and \$0.06 per Mcfe for each of the six months ended June 30, 2010 and 2009 related to

accretion
expense on asset
retirement
obligations.

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Quarter and Six Months Ended June 30, 2010 Compared to Quarter and Six Months Ended June 30, 2009

Our EBIT for the quarter and six months ended June 30, 2010 increased $42 million and $2.1 billion as compared to the same periods in 2009. The table below shows the significant variances of our financial results for the quarter and six months ended June 30, 2010 as compared to the same periods in 2009:

	Quarter Ended June 30, 2010 Variance				Six Months Ended June 30, 2010 Variance			
	Operating Revenue	Operating Expense	Other	EBIT	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)							
Physical sales								
Natural gas								
Higher realized prices in 2010	$ 48	$	$	$ 48	$ 86	$	$	$ 86
Higher volumes in 2010	4			4	2			2
Oil, condensate and NGL								
Higher realized prices in 2010	30			30	81			81
Higher volumes in 2010	7			7	3			3
Realized and unrealized gains on financial derivatives	(24)			(24)	(165)			(165)
Other revenues	(5)			(5)				
Depreciation, depletion and amortization expense								
Lower (higher) depletion rate in 2010		(32)		(32)		8		8
Higher production volumes in 2010		(5)		(5)		(2)		(2)
Production costs								
Lower (higher) lease operating expenses in 2010		(5)		(5)		5		5
Higher production taxes in 2010		(5)		(5)		(6)		(6)
Ceiling test charges		12		12		2,078		2,078
Earnings from investment in Four Star			11	11			21	21
Other		1	5	6		(1)	7	6
Total Variances	$ 60	$ (34)	$ 16	$ 42	$ 7	$ 2,082	$ 28	$ 2,117

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the quarter and six months ended June 30, 2010, natural gas, oil, condensate and NGL revenues increased as compared to the same periods in 2009 due to higher commodity prices and higher production volumes.

Realized and unrealized gains on financial derivatives. During the quarter and six months ended June 30, 2010, we recognized net gains of $31 million and $284 million compared to net gains of $55 million and $449 million during the same periods in 2009. Gains or losses each period are based on movements of forward commodity prices relative to the prices in our underlying financial derivative contracts.

Depreciation, depletion and amortization expense. During the quarter ended June 30, 2010, our depreciation, depletion and amortization expense increased compared with the same period in 2009 as a result of a higher depletion rate and higher production volumes. During the six months ended June 30, 2010, our depreciation, depletion and amortization expense decreased as a result of a lower depletion rate partially offset by higher production volumes. The second quarter 2009 depletion rate was largely impacted by the ceiling test charges recorded in the first quarter of 2009, and we continue to experience a lower overall depletion rate in 2010 as a result of that charge. We expect our depreciation, depletion and amortization rate during the second half of the year to be between $1.80/Mcfe and $1.85/Mcfe.

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Production costs. During the quarter ended June 30, 2010, our production costs increased as compared to the same period in 2009 primarily due to higher lease operating expenses and production taxes. Lease operating expenses were higher due to production from our Brazilian Camarupim Field beginning in late 2009 while the higher production taxes were a result of higher natural gas and oil revenues. During the six months ended June 30, 2010, our production costs were relatively flat compared to the same period in 2009 due to lower lease operating expenses offset by higher production taxes. Lease operating expenses were lower due to a decrease in our domestic maintenance and repair expenses partially offset by Brazil production increases while the higher production taxes were as a result of higher natural gas and oil revenues.

Ceiling test charges. In the first six months 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 quarter and six months ended June 30, 2009, we recorded non-cash ceiling test charges of $12 million and $21 million as a result of a dry hole drilled in the South Mariut block. Additionally, during the quarter ended March 31, 2009, we recorded non-cash ceiling test charges of approximately $2.0 billion in our domestic full cost pool and $28 million in our Brazilian full cost pool.

Other. Our equity earnings from Four Star increased by $11 million and $21 million during the quarter and six months ended June 30, 2010 as compared to the same periods in 2009 primarily due to the impact of higher commodity prices partially offset by lower production volumes.

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Marketing Segment

Overview.

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. Our primary unhedged exposure remaining in the Marketing segment at June 30, 2010 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. Early in the third quarter of 2010, we entered into positions with a third party financial institution that eliminated the locational price risks on approximately 60 percent of the volumes to be delivered under the PJM contracts, including the locational price risks on all volumes beyond 2013.

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 June 30, 2010, these contracts require us to pay demand charges of $28 million in 2010 and an average of $41 million per year between 2011 and 2014.

Natural gas contracts. As of June 30, 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

Our overall operating results and analysis for our Marketing segment during each of the quarters and six months ended June 30 are as follows:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In millions)			
Income (Loss)				
Contracts Related to Legacy Trading Operations:				
Changes in fair value of power contracts	$ (39)	$ 21	$ (21)	$ 55
Natural gas transportation-related contracts:				
Demand charges	(10)	(8)	(19)	(17)
Settlements, net of termination payments	5	5	16	12
Changes in fair value of natural gas contracts	(4)	(3)	(5)	18
Total revenues	(48)	15	(29)	68
Operating expenses	(1)	(5)	(3)	(6)
EBIT	$ (49)	$ 10	$ (32)	$ 62

During the quarters ended June 30, 2010 and 2009, and the six months ended June 30, 2010, our results were primarily impacted by changes in the fair value of our legacy power contracts in PJM. Our results for the first six months of 2009 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).

Corporate and Other Expenses, Net

Our corporate and other activities include our general and administrative functions as well as our recently formed midstream business, our remaining power operations, and miscellaneous businesses. The following is a summary of significant items impacting the EBIT in our corporate and other activities for the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(In millions)			
Income (Loss)				
Change in litigation, environmental and other reserves	$ 10	$ 25	$ 2	$ 22
Equity earnings	6		12	7
Loss on sale of notes receivable		(22)		(22)
Other	10	7	1	
Total EBIT	$ 26	$ 10	$ 15	$ 7

Litigation, Environmental, and Other Reserves. During the quarter and six months ended June 30, 2010, our EBIT was primarily impacted by the favorable resolution of certain legacy indemnifications. In 2009, we recorded income primarily associated with an indemnification related to the sale of a legacy ammonia facility that fluctuates with ammonia prices. 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 and six months ended June 30, 2010 and 2009, our equity earnings were primarily from legacy power investments.

Loss on Sale of Notes Receivable. In the first quarter of 2009, we completed the sale of our investment in Porto Velho to our partner in the project for total consideration of $179 million, including $78 million in notes receivable. Subsequently, in the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of $22 million.

Other. During the second quarter of 2010, our EBIT was impacted by the refund of certain insurance premiums on legacy activities. In addition, other includes non-cash pension costs and other benefit costs related to legacy activities. Losses from our pension asset performance during 2008 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.

Interest and Debt Expense

Our interest and debt expense increased during the quarter and six months ended June 30, 2010 as compared to the same periods in 2009 primarily due to entering into a term loan with GIP related to our Ruby pipeline project during the third quarter of 2009. Additionally, during the second quarter of 2010, the interest rate on the Ruby term loan increased from 7 percent to 13 percent as further described in Note 13. Our second quarter 2010 results were also impacted by changes in our estimates in the allowance for funds used during construction.

Income Taxes

	Quarters Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009

	(In millions, except for rates)			
Income taxes	$ 82	$ 66	$ 268	$ (460)
Effective tax rate	31%	40%	31%	35%

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

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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. Our preliminary estimate of the first-year cost to our company is more than $10 million.

The EPA has also adopted regulations that will require permits to be obtained under the Clean Air Act for GHG emissions above certain thresholds. Depending on the thresholds ultimately established by the EPA, these permit requirements could have a material impact upon the costs of our 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 new and existing facilities. The EPA s regulations are being challenged in the federal courts; however, pending such judicial reviews, the thresholds that have been established by the EPA through at least 2016 are not expected to have a material impact on our operations or financial results.

It is uncertain what federal or state legislation or regulations will ultimately be adopted and whether adopted regulations 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 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 $27 million in capital expenditures over the period from 2010 to 2013.

In February 2010, the EPA promulgated a new one-hour National Ambient Air Quality Standard (NAAQS) for oxides of nitrogen (NO_2). The new standard is in addition to the existing annual NAAQS which was not changed. While it is uncertain how the EPA and the states will apply the new one-hour NAAQS, the new NAAQS may impact our ability to obtain permits and other regulatory approvals with regard to existing and new facilities and may cause us to incur costs to install additional controls on existing and new facilities. The EPA s new rule is being challenged in the federal courts. While the new NAAQS, if upheld, could have a material impact on our cost of operations and our cost to install new facilities, we are unable, at this point, to estimate its financial impact.

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Liquidity and Capital Resources

In 2010, 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 and 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. At June 30, 2010, our available liquidity was approximately $2.9 billion (approximately $0.7 billion cash and $2.2 billion of available credit facility), exclusive of combined cash and credit facility capacity of EPB and Ruby. Through June 30, 2010, we completed several funding actions including (i) receiving $1.2 billion in cash in conjunction with contributing ownership interests in SLNG, Elba Express and SNG to our MLP, which funded the acquisitions through the issuance of $0.5 billion of debt and the issuance of common units, (ii) selling certain of our interests in Mexican pipeline and compression assets for approximately $0.3 billion and (iii) entering into a seven-year amortizing $1.5 billion financing facility for our Ruby pipeline project that matures in 2017. In August 2010, we made a draw of approximately $250 million under the Ruby pipeline facility and GIP contributed $120 million for a convertible preferred interest in Ruby. As a result of these actions and the funding from GIP, we have met our planned 2010 funding requirements and are currently addressing our 2011 funding needs.

As further discussed in Item 1, Financial Statements, Notes 8 and 13, we entered into an agreement with GIP where they would invest up to $700 million for a 50 percent equity interest in Ruby. As of June 30, 2010, GIP had funded $550 million related to the Ruby pipeline project, including $145 million 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 $405 million advanced under a loan commitment with GIP. 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 in Ruby to common equity in Ruby at any time; however, the preferred equity is subject to mandatory conversion to Ruby common equity upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements. 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.

Our 2010 full year capital requirements, including our Ruby pipeline project, other pipeline projects and exploration and production expenditures, are significant; however, our 2011 requirements decline significantly, and by the end of 2011 most of our pipeline backlog will be placed in service. Our cash capital expenditures for the six months ended June 30, 2010, and the amount of cash we expect to spend for the remainder of 2010 to grow and maintain our businesses are as follows:

	Six Months Ended June 30, 2010	2010 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.1	$ 0.3	$ 0.4
Growth(1)	0.8	1.7	2.5
Exploration and Production	0.6	0.5	1.1
Other	0.1		0.1
	$ 1.6	$ 2.5	$ 4.1

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

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In addition to our capital needs, for the remainder of 2010 we have approximately $100 million of debt that will mature. This does not include approximately $405 million of Ruby debt that converted into Ruby preferred equity in August 2010.

Our operating cash flows from our core businesses, our financing actions taken to date and our available liquidity have allowed us to meet our operating, financing and capital needs for 2010, and we are currently addressing our 2011 funding needs. 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. There are a number of factors that could impact our plans, including our ability to access the financial markets to fund our long-term capital needs if the financial markets are restricted, or a further decline in commodity prices. If these events occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets, all of which could impact our financial and operating performance.

Overview of Cash Flow Activities. During the first six months of 2010, we generated operating cash flow of approximately $1.0 billion primarily from our pipeline and exploration and production operations. We also generated approximately $0.3 billion from the sale of certain of our interests in Mexican pipeline and compression assets, approximately $0.5 billion as a result of the issuance of MLP common units (in conjunction with our sale of additional pipeline assets to the MLP), and approximately $1.0 billion in debt proceeds primarily from MLP debt offerings and other consolidated project financings. We used the cash flow generated from these operating and financing activities to fund our capital programs, make net repayments under our various credit facilities and other debt obligations, and pay common and preferred dividends. For the six months ended June 30, 2010, our cash flows from continuing operations are summarized as follows:

		2010 (In billions)
Cash Flow from Operations		
Operating activities		
Net income	$	0.6
Income adjustments		0.6
Change in assets and liabilities		(0.2)
Total cash flow from operations	$	1.0
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets and investments	$	0.3
Financing activities		
Net proceeds from the issuance of long-term debt		1.0
Net proceeds from the issuance of noncontrolling interests		0.5
		1.5
Total other cash inflows	$	1.8
Cash Outflows		

Investing activities		
Capital expenditures	$	1.6
Financing activities		
Payments to retire long-term debt and other financing obligations		1.0
Dividends and other		0.1
		1.1
Total cash outflows	$	2.7
Net change in cash	$	0.1

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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 June 30, 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	$ 267	$ 114	$ 4	$ 7	$ 392
Liabilities	(198)	(237)	(113)	(45)	(593)
Total commodity-based derivatives	$ 69	$ (123)	$ (109)	$ (38)	$ (201)

The following is a reconciliation of our commodity-based derivatives for the six months ended June 30, 2010:

	Commodity-Based Derivatives (In millions)
Fair value of contracts outstanding at January 1, 2010	$ (381)
Fair value of contract settlements during the period	(91)
Premiums paid during the period	7
Changes in fair value of contracts during the period	264
Net changes in contracts outstanding during the period	180
Fair value of contracts outstanding at June 30, 2010	$ (201)

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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)					
June 30, 2010	$ 273	$ 152	$ (121)	$ 399	$ 126
December 31, 2009	$ 127	$ (29)	$ (156)	$ 290	$ 163
Other commodity-based derivatives net assets (liabilities)					
June 30, 2010	$ (474)	$ (479)	$ (5)	$ (469)	$ 5
December 31, 2009	$ (508)	$ (517)	$ (9)	$ (500)	$ 8

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 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 June 30, 2010.

Changes in Internal Control over Financial Reporting

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

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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. Below is an additional risk factor that may arise as a result of the recent oil spill in the Gulf of Mexico, as well as the recent financial reform legislation that was enacted in July 2010.

Our operations and financial results could be impacted by the recent oil spill in the Gulf of Mexico and recently enacted legislative reforms, or by further developments in other potential regulatory, legislative or environmental initiatives.

The recent oil spill in the Gulf of Mexico poses additional risks for our exploration and production and pipeline businesses, including the possibility of (i) new environmental and safety review requirements imposed on drilling and/or development operations in the Gulf of Mexico and other areas, (ii) constrained industry access to the Gulf of Mexico, (iii) other indirect effects from the oil spill such as greater scrutiny and regulation of exploration and production operations, which may include delays in the receipt of necessary permits and approvals both in the U.S. and internationally, including our offshore exploration and production operations in Brazil and (iv) negative impacts on the availability and cost of insurance coverages applicable to offshore operations. While we have reduced our focus over the past several years in the Gulf of Mexico, any of these items could have an adverse impact on our strategy and profitability in both our domestic and international exploration and production operations and on supplies of natural gas from the Gulf of Mexico to certain of our pipeline systems. In addition, we have numerous contractual arrangements with many of the parties involved in the oil spill. Although in many cases the parties remain creditworthy or have posted credit support associated with these contractual arrangements, there is a risk that one or more of the parties could default in the performance of our contracts.

In July 2010, federal legislation was enacted to implement various financial and governance reforms. Although many of the legislative provisions were focused on the financial and banking industries, portions of the legislation will impact our businesses. The extent of the impact is uncertain at this time, due to the requirement that various implementing regulations must be adopted by the SEC and the United States Commodity Futures Trading Commission (CFTC). For example, the legislation provides for the creation of certain position limits for derivative transactions, as well as certain exemptions from the general requirement that swap transactions must be cleared through a central exchange for which collateral must be posted. The CFTC must adopt regulations that define what position limits will be imposed and what swap transactions are entitled to such exemptions. Although we believe the derivative contracts that we enter into to hedge the commodity price risk associated with our natural gas and oil production should not be impacted by such position limits and should be exempt from the requirement to clear transactions through a central exchange or to post any collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

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.

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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: August 9, 2010

By: /s/ John R. Sult
John R. Sult
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 9, 2010

By: /s/ Francis C. Olmsted, III
Francis C. Olmsted, III
Vice President and Controller
(Principal Accounting Officer)

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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
10.A	Credit Agreement dated as of May 3, 2010 among Ruby Pipeline, L.L.C, as the Borrower, Société Générale, as the Administrative Agent, Deutsche Bank Trust Company Americas, as the Common Security Trustee, Construction/Term Loan Lenders, DSRA Issuing Banks, and Revolving Loan Lender/Issuing Bank (incorporated by reference to Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.B	Non-Completion Loan Guaranty by El Paso Corporation, as the Guarantor, in favor of Société Générale as the Administrative Agent, dated as of May 3, 2010 (incorporated by reference to Exhibit 10.B to our Current Report on Form 8-K filed with the SEC on May 11, 2010).
10.C	El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated effective May 19, 2010 (incorporated by reference to Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on May 20, 2010).
*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.