EL PASO CORP/DE
Form 10-Q
August 08, 2011

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, 2011

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 (State or Other Jurisdiction of Incorporation or Organization)	**76-0568816** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of Principal Executive Offices)	**77002** (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, 2011: 770,247,634

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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
Bcf	= billion cubic feet
GW	= gigawatts
GWh	= gigawatt hours
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
NGL	= natural gas liquids
TBtu	= trillion British thermal units

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

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

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PART I 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,	
	2011	2010	2011	2010
Operating revenues	$ 1,236	$ 1,018	$ 2,225	$ 2,419
Operating expenses				
Cost of products and services	44	53	91	106
Operation and maintenance	323	285	628	586
Depreciation, depletion and amortization	262	242	516	460
Taxes, other than income taxes	78	54	154	123
	707	634	1,389	1,275
Operating income	529	384	836	1,144
Earnings from unconsolidated affiliates	32	111	62	139
Loss on debt extinguishment	(27)		(68)	
Other income, net	82	57	181	117
Interest and debt expense	(239)	(284)	(479)	(527)
Income before income taxes	377	268	532	873
Income tax expense	38	82	57	268
Net income	339	186	475	605
Net income attributable to noncontrolling interests	(77)	(29)	(151)	(60)
Net income attributable to El Paso Corporation	262	157	324	545
Preferred stock dividends of El Paso Corporation		10		19
Net income attributable to El Paso Corporation s common stockholders	$ 262	$ 147	$ 324	$ 526
Basic earnings per common share				
Net income attributable to El Paso Corporation s common stockholders	$ 0.34	$ 0.21	$ 0.44	$ 0.75
Diluted earnings per common share				
Net income attributable to El Paso Corporation s common stockholders	$ 0.34	$ 0.21	$ 0.42	$ 0.72

Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.01	$ 0.02	$ 0.02

See accompanying notes.

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Net income	$ 339	$ 186	$ 475	$ 605
Pension and postretirement obligations:				
Reclassification of net actuarial losses during period (net of income taxes of $7 and $14 in 2011 and $6 and $12 in 2010)	15	11	31	24
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $15 and $13 in 2011 and $23 and $25 in 2010)	(27)	(37)	(24)	(40)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 and $2 in 2011 and $1 and $2 in 2010)	4	2	7	4
Other comprehensive income (loss)	(8)	(24)	14	(12)
Comprehensive income	331	162	489	593
Comprehensive income attributable to noncontrolling interests	(77)	(29)	(151)	(60)
Comprehensive income attributable to El Paso Corporation	$ 254	$ 133	$ 338	$ 533

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, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents (include $38 in 2011 and $31 in 2010 held by variable interest entities)	$ 260	$ 347
Accounts and notes receivable		
Customer, net of allowance of $5 in 2011 and $4 in 2010	329	333
Affiliates	6	7
Other	183	160
Materials and supplies	180	169
Assets from price risk management activities	204	265
Deferred income taxes	284	165
Other	106	106
Total current assets	1,552	1,552
Property, plant and equipment, at cost		
Pipelines (include $4,029 in 2011 and $3,232 in 2010 held by variable interest entities)	23,378	22,385
Oil and natural gas properties, at full cost	22,331	21,692
Other	477	416
	46,186	44,493
Less accumulated depreciation, depletion and amortization	23,617	23,421
Total property, plant and equipment, net	22,569	21,072
Other long-term assets		
Investments in unconsolidated affiliates	1,689	1,673
Assets from price risk management activities	36	61
Other	1,112	912
	2,837	2,646
Total assets	$ 26,958	$ 25,270

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, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 474	$ 610
Affiliates	11	9
Other	423	386
Short-term financing obligations, including current maturities	618	489
Liabilities from price risk management activities	194	176
Asset retirement obligations	65	63
Accrued interest	203	202
Other	579	630
Total current liabilities	2,567	2,565
Long-term financing obligations, less current maturities	13,594	13,517
Other long-term liabilities		
Liabilities from price risk management activities	387	397
Deferred income taxes	764	568
Other	1,436	1,461
	2,587	2,426
Commitments and contingencies (Note 8)		
Preferred stock of subsidiaries	763	698
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 as of December 31, 2010; stated at liquidation value		750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 785,159,805 shares in 2011 and 719,743,724 shares in 2010	2,355	2,159
Additional paid-in capital	5,444	4,484
Accumulated deficit	(2,110)	(2,434)
Accumulated other comprehensive loss	(737)	(751)
	(282)	(291)

Treasury stock (at cost); 15,053,056 shares in 2011 and 15,492,605 shares in 2010		
Total El Paso Corporation stockholders equity	4,670	3,917
Noncontrolling interests	2,777	2,147
Total equity	7,447	6,064
Total liabilities and equity	$ 26,958	$ 25,270

See accompanying notes.

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash flows from operating activities		
Net income	$ 475	$ 605
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	516	460
Deferred income tax expense	73	270
Earnings from unconsolidated affiliates, adjusted for cash distributions	(31)	(104)
Loss on debt extinguishment	68	
Other non-cash income items	(96)	(22)
Asset and liability changes	(9)	(315)
Net cash provided by operating activities	996	894
Cash flows from investing activities		
Capital expenditures	(2,016)	(1,502)
Net proceeds from the sale of assets and investments	29	293
Increase in notes receivable	(112)	(16)
Other		27
Net cash used in investing activities	(2,099)	(1,198)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	2,976	965
Payments to retire long-term debt and other financing obligations	(2,861)	(1,060)
Net proceeds from issuance of noncontrolling interests	948	549
Distributions to noncontrolling interest holders	(86)	(39)
Net proceeds from issuance of preferred stock of subsidiary	30	
Distributions to holders of preferred stock of subsidiary	(10)	(10)
Dividends paid	(23)	(33)
Proceeds from stock option exercises	43	4
Other	(1)	
Net cash provided by financing activities	1,016	376
Change in cash and cash equivalents	(87)	72
Cash and cash equivalents		
Beginning of period	347	635
End of period	$ 260	$ 707

See accompanying notes.

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning of period	$ 750	$ 750
Conversion of preferred stock	(750)	
Balance at end of period		750
Common stock:		
Balance at beginning of period	2,159	2,148
Conversion of preferred stock	174	
Other, net	22	10
Balance at end of period	2,355	2,158
Additional paid-in capital:		
Balance at beginning of period	4,484	4,501
Conversion of preferred stock	576	
Dividends	(14)	(33)
Issuances of noncontrolling interests (Note 10)	338	
Other, including stock-based compensation	60	19
Balance at end of period	5,444	4,487
Accumulated deficit:		
Balance at beginning of period	(2,434)	(3,192)
Net income attributable to El Paso Corporation	324	545
Balance at end of period	(2,110)	(2,647)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(751)	(718)
Other comprehensive income (loss)	14	(12)
Balance at end of period	(737)	(730)
Treasury stock, at cost:		
Balance at beginning of period	(291)	(283)
Stock-based and other compensation	9	(7)
Balance at end of period	(282)	(290)

Total El Paso Corporation stockholders equity at end of period	4,670	3,728
Noncontrolling interests:		
Balance at beginning of period	2,147	785
Issuances of noncontrolling interests (Note 10)	610	549
Distributions to noncontrolling interests	(86)	(39)
Net income attributable to noncontrolling interests (Note 10)	106	50
Balance at end of period	2,777	1,345
Total equity at end of period	$ 7,447	$ 5,073

See accompanying notes.

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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). As 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) and should be read along with our 2010 Annual Report on Form 10-K. The financial statements as of June 30, 2011, and for the quarters and six months ended June 30, 2011 and 2010, are unaudited. The condensed consolidated balance sheet as of December 31, 2010 was derived from the audited balance sheet filed in our 2010 Annual Report on 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. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation, none of which impacted our reported net income or stockholders equity. Additionally, our statement of cash flows for the six months ended June 30, 2010 reflects a decrease in both net cash provided by operating activities and net cash used in investing activities related to the timing of certain capital expenditures which was considered immaterial to our 2010 consolidated financial statements. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year. Our disclosures in this Form 10-Q are an update to those provided in our 2010 Annual Report on Form 10-K.

On May 24, 2011, we announced that our Board of Directors had granted initial approval of a plan to separate the Company into two publicly traded businesses by the end of 2011. The plan calls for a tax-free spin-off of our exploration and production business and related activities into a new publicly traded company separate from El Paso Corporation (EPC). The planned separation is subject to market, regulatory, tax and final approval by our Board of Directors and other customary conditions. Until the separation is complete, the results of operations, financial position and cash flows of our exploration and production business will be reported as continuing operations.

Significant Accounting Policies

There were no changes in the significant accounting policies described in our 2010 Annual Report on Form 10-K and no significant accounting pronouncements issued but not yet adopted as of June 30, 2011.

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 in earnings from unconsolidated affiliates. In July 2011, we sold oil and natural gas properties located in Alabama for approximately $104 million.

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3. Other Income, Net

The following are the components of other income and other expense for the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Other Income, Net				
Allowance for equity funds used during construction	$ 74	$ 51	$ 171	$ 101
Other	8	6	10	16
Total	$ 82	$ 57	$ 181	$ 117

Allowance for Equity Funds Used During Construction. As allowed by the Federal Energy Regulatory Commission (FERC), we capitalize a pre-tax carrying cost on equity funds related to the construction of long-lived assets in our FERC regulated business and reflect this amount as an increase in the cost of the asset on our balance sheet. We calculate this amount using the most recent FERC approved equity rate of return. These amounts are recovered over the depreciable lives of the long-lived assets to which they relate.

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,	
	2011	2010	2011	2010
	(In millions, except rates)			
Income tax expense	$ 38	$ 82	$ 57	$ 268
Effective tax rate	10%	31%	11%	31%

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 in which they occur. 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, 2011, our effective tax rate was significantly lower than the statutory rate primarily due to the benefit to our anticipated annual effective tax rate of income attributable to nontaxable noncontrolling interests of El Paso Pipeline Partners, L.P. (EPB), dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends and the favorable resolution of certain tax matters. 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 of 2010 from healthcare legislation enacted in March 2010.

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5. Earnings Per Share

Basic and diluted earnings per common share were as follows for the quarters and six months ended June 30:

Quarters Ended June 30,

	2011		2010	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 262	$ 262	$ 157	$ 157
Preferred stock dividends of El Paso Corporation			(10)	
Interest on trust preferred securities		3		
Net income attributable to El Paso Corporation s common stockholders	$ 262	$ 265	$ 147	$ 157
Weighted average common shares outstanding	763	763	698	698
Effect of dilutive securities:				
Options and restricted stock		11		5
Convertible preferred stock				58
Trust preferred securities		8		
Weighted average common shares outstanding and dilutive securities	763	782	698	761
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.34	$ 0.34	$ 0.21	$ 0.21

Six Months Ended June 30,

	2011		2010	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 324	$ 324	$ 545	$ 545
Preferred stock dividends of El Paso Corporation			(19)	
Interest on trust preferred securities				5
Net income attributable to El Paso Corporation s common stockholders	$ 324	$ 324	$ 526	$ 550
Weighted average common shares outstanding	738	738	697	697
Effect of dilutive securities:				
Options and restricted stock		11		5
Convertible preferred stock		22		58
Trust preferred securities				8
	738	771	697	768

Weighted average common shares outstanding and dilutive securities				
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.44	$ 0.42	$ 0.75	$ 0.72

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. Our potentially dilutive securities consist of employee stock options, restricted stock, trust preferred securities and convertible preferred stock. In March 2011, we converted our preferred stock to common stock as further described in Note 10. For the quarters and six months ended June 30, 2011 and 2010, certain of our employee stock options were antidilutive. Additionally, for the quarter ended June 30, 2010 and the six months ended June 30, 2011, our trust preferred securities were antidilutive.

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6. Financial Instruments

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

	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 14,212	$ 15,799	$ 14,006	$ 14,686
Marketable securities in non-qualified compensation plans	21	21	20	20
Commodity-based derivatives	(246)	(246)	(186)	(186)
Interest rate derivatives	(95)	(95)	(61)	(61)
Other	(12)	(12)	(11)	(11)

As of June 30, 2011 and December 31, 2010, the carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and short-term financing obligations represent fair value because of the short-term nature of these instruments. The carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on the nature of their interest rates and our assessment of the ability to recover these amounts. We estimated the fair value of our long-term financing obligations based on quoted market prices for the same or similar issues, including consideration of our credit risk related to those instruments.

Our derivative financial instruments are further described in our 2010 Annual Report on Form 10-K and below:

Production-Related Commodity Based Derivatives. As of June 30, 2011 and December 31, 2010, we have production-related derivatives (oil and natural gas swaps, collars, basis swaps and option contracts) to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas production on 17,382 MBbl and 12,240 MBbl of oil and 200 TBtu and 283 TBtu of natural gas. None of these contracts are designated as accounting hedges.

Other Commodity-Based Derivatives. As of June 30, 2011 and December 31, 2010, in our Marketing segment we have forwards, swaps and options contracts related to long-term natural gas and power. These contracts, the longest of which extends into 2019, include (i) obligations to sell natural gas to power plants ranging from 12,550 MMBtu/d to 95,000 MMBtu/d and (ii) an obligation 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 1,700 to 3,700 GWh, to provide annually approximately 1,700 GWh of power and approximately 71 GW of installed capacity in the PJM power pool. We have entered into contracts to economically mitigate our exposure to commodity price changes and locational price differences on substantially all of these natural gas and power volumes. None of these derivatives are designated as accounting hedges.

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, 2011 and December 31, 2010, we had interest rate swaps that are designated as cash flow hedges that effectively convert the interest rate on approximately $1.3 billion 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, 2011 relates to debt associated with our Ruby pipeline project that began accruing interest on July 1, 2011 and have termination dates ranging from June 2013 to June 2017. These termination dates correspond to the estimated principal outstanding on the Ruby debt over the term of these swaps. For a further discussion of our Ruby financing, see Note 7.

We also have long-term debt with fixed interest rates that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps designated as fair value hedges to protect the value of certain of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments. We record changes in the fair value of these derivatives in interest expense which is offset by changes in the fair value of the related hedged items. As of June 30, 2011 and December 31, 2010, these interest rate swaps converted the interest rate on approximately $162 million and $184 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%.

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Fair Value Measurement. We separate the fair values of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument. During the quarter and six months ended June 30, 2011, there have been no changes to the inputs and valuation techniques used to measure fair value, the types of instruments, or the levels in which they are classified. Our marketable securities in non-qualified compensation plans and other are reflected at fair value on our balance sheets as other long-term assets, other current liabilities and other long-term liabilities. We net our derivative assets and liabilities for counterparties where we have a legal right of offset and classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. At June 30, 2011 and December 31, 2010, cash collateral held was not material. The following table presents the fair value of our financial instruments at June 30, 2011 and December 31, 2010 (in millions).

	June 30, 2011				December 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Commodity-based derivatives								
Production-related oil and natural gas derivatives	$	$ 285	$	$ 285	$	$ 373	$	$ 373
Other natural gas derivatives		116	16	132		139	18	157
Power-related derivatives			23	23			31	31
Total commodity-based derivative assets		401	39	440		512	49	561
Interest rate derivatives designated as hedges								
Fair value hedges		5		5		8		8
Impact of master netting arrangements		(194)	(11)	(205)		(229)	(14)	(243)
Total price risk management assets	$	$ 212	$ 28	$ 240	$	$ 291	$ 35	$ 326
Marketable securities in non-qualified compensation plans	21			21	20			20
Total net assets	$ 21	$ 212	$ 28	$ 261	$ 20	$ 291	$ 35	$ 346
Liabilities								
Commodity-based derivatives								
	$	$ (159)	$	$ (159)	$	$ (136)	$	$ (136)

Production-related oil and natural gas derivatives								
Other natural gas derivatives		(133)	(67)	(200)		(162)	(90)	(252)
Power-related derivatives			(327)	(327)			(359)	(359)
Total commodity-based derivative liabilities		(292)	(394)	(686)		(298)	(449)	(747)
Interest rate derivatives designated as hedges								
Cash flow hedges		(100)		(100)		(69)		(69)
Impact of master netting arrangements		194	11	205		229	14	243
Total price risk management liabilities	$	$ (198)	$ (383)	$ (581)	$	$ (138)	$ (435)	$ (573)
Other			(13)	(13)			(12)	(12)
Total net liabilities	$	$ (198)	$ (396)	$ (594)	$	$ (138)	$ (447)	$ (585)
Total	$ 21	$ 14	$ (368)	$ (333)	$ 20	$ 153	$ (412)	$ (239)

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. Based on our assessment of counterparty risk in light of the collateral our counterparties have posted with us (primarily in the form of letters of credit), we have 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 quarter and six months ended June 30, 2011:

	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues[1]	Change in Fair Value Reflected in Operating Expenses[2]	Settlements	Balance at End of Period
	(In millions)				
Quarter Ended June 30, 2011					
Assets	$ 32	$ (3)	$	$ (1)	$ 28
Liabilities	(416)	(5)	(5)	30	(396)
Total	$ (384)	$ (8)	$ (5)	$ 29	$ (368)
Six Months Ended June 30, 2011					
Assets	$ 35	$ (6)	$	$ (1)	$ 28
Liabilities	(447)	(3)	(6)	60	(396)
Total	$ (412)	$ (9)	$ (6)	$ 59	$ (368)

(1) Includes approximately $6 million and $10 million of net losses that had not been realized through settlements for the quarter and six months ended June 30, 2011.

(2) Includes approximately $4 million and $5 million of net losses that had not been realized through settlements for the quarter and six months ended June 30, 2011.

Below are the impacts of our commodity-based and interest rate derivatives to our statements of income and statements of comprehensive income (loss) for the quarters and six months ended June 30:

	2011			2010		
	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)
	(In millions)					
Quarters ended June 30,						
Production-related derivatives	$ 132	$	$ 3	$ 31	$	$ 3
Other natural gas and power derivatives	(6)			(43)		
Total interest rate derivatives		4	(34)		4	(45)
Total	$ 126	$ 4	$ (31)	$ (12)	$ 4	$ (42)

Six months ended June 30,						
Production-related derivatives	$ 23	$	$ 6	$ 284	$	$ 6
Other natural gas and power derivatives	(7)			(26)		
Total interest rate derivatives		8	(31)		9	(46)
Total	$ 16	$ 8	$ (25)	$ 258	$ 9	$ (40)

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7. Debt, Other Financing Obligations and Other Credit Facilities

	June 30, 2011	December 31, 2010
	(In millions)	
Short-term financing obligations, including current maturities	$ 618	$ 489
Long-term financing obligations	13,594	13,517
Total	$ 14,212	$ 14,006

Changes in Financing Obligations. During the six months ended June 30, 2011, we had the following changes in our financing obligations:

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Ruby Pipeline, L.L.C. credit facility	variable	$ 391	$ 391
Southern Natural Gas Company, L.L.C. (SNG) notes due 2021	4.40 %	300	297
El Paso Exploration and Production Company (EPEP) revolving credit facility	variable	925	918
El Paso revolving credit facility	variable	571	562
El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC) revolving credit facility	variable	815	808
Increases through June 30, 2011		$ 3,002	$ 2,976
Repayments, repurchases, and other			
EPEP revolving credit facility	variable	$ (825)	$ (825)
El Paso revolving credit facility	variable	(796)	(796)
EPPOC revolving credit facility	variable	(715)	(715)
El Paso notes due 2011	7.00 %	(105)	(105)
El Paso notes due 2012 through 2032	7.25% - 12.00 %	(347)	(410)
Other	various	(8)	(10)
Decreases through June 30, 2011		$ (2,796)	$ (2,861)

In July 2011, our debt increased by approximately $650 million net of an additional $274 million of debt we repurchased under our early tender offer. We anticipate spending up to an additional $438 million in August 2011 to buy back additional debt. In conjunction with these transactions we anticipate recording losses of approximately $100 million during the third quarter of 2011. The majority of the July debt increase diversified our sources of liquidity.

Repurchase of Senior Notes. During the six months ended June 30, 2011, we repurchased approximately $350 million of our senior unsecured notes. In conjunction with these transactions, we recorded total losses on debt extinguishment of $27 million and $68 million during the quarter and six months ended June 30, 2011.

Refinancing of Revolving Credit Facilities. During the six months ended June 30, 2011, we refinanced $3.25 billion in revolving credit facilities to extend their maturity to 2016. As part of the revolver refinancings, we reduced the overall borrowing capacity on the El Paso facility from $1.5 billion to $1.25 billion and increased the overall borrowing capacity on the EPPOC facility from $0.75 billion to $1.0 billion (expandable to $1.5 billion for certain expansion projects and acquisitions). Our cost to borrow under these facilities has increased to LIBOR plus 2.25 for El Paso, LIBOR plus 2.00 for EPB and LIBOR plus 1.50 to 2.50 for EPEP. The El Paso facility collateral support now includes the general partnership interests in EPB while certain collateral restrictions have been modified providing us the ability to sell up to 100 percent of our ownership interests in either El Paso Natural Gas Company (EPNG) or Tennessee Gas Pipeline Company (TGP), or some combination thereof, to EPB. Upon achieving investment grade status by one of the rating agencies, collateral support on the El Paso facility will be eliminated. As of June 30, 2011, we were in compliance with all of our debt covenants of which there were no material changes from those reported in our 2010 Annual Report on Form 10-K.

Credit Facilities/Letters of Credit. We have various credit facilities in place, including the above revolvers, which allow us to borrow funds or issue letters of credit. During the first six months of 2011, we increased the total letter of credit capacity under certain existing and new letter of credit facilities by $175 million with a weighted average fixed facility fee of 1.78 percent and maturities ranging from April 2012 to September 2014. As of June 30, 2011, the aggregate amount outstanding under all of our credit facilities was $0.4 billion (excluding $0.4 billion outstanding on the EPPOC $1.0 billion revolving credit facility) and $0.9 billion of letters of credit and surety bonds issued, including $0.4 billion related to our price risk management activities and $0.2 billion related to Ruby as discussed below. Our total available capacity under all of our facilities was approximately $2.5 billion as of June 30, 2011 (not including capacity available under the EPPOC $1.0 billion revolving credit facility). In July 2011, our $500 million unsecured credit facility matured.

Ruby Pipeline Financing. During 2010, we entered into a seven-year amortizing $1.5 billion financing facility for our Ruby pipeline project (see Note 12) that requires principal payments at various dates through June 2017. As of June 30, 2011, we have utilized all of the available capacity under this facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance $700 million of the facility by the end of year four. If we do not refinance $700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that began converting the floating LIBOR interest rate to fixed interest rates in July 2011 on approximately $1.1 billion of total borrowings under this agreement. As of July 31, 2011, we also had $100 million outstanding ($170 million as of June 30, 2011) in letters of credit related to Ruby. Upon making certain permitting representations, and obtaining consents and/or waivers of certain customary conditions, our Ruby project financing obligations will become non-recourse to us.

8. 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. In 2010, a trial court dismissed all of the claims in this matter. The dismissal of the case has been appealed.

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. Several of the cases have been settled or dismissed. The remaining cases, which were pending in Nevada, were dismissed. Appeals have been filed. Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, our costs and legal exposure related to the remaining outstanding lawsuits and claims are not currently determinable.

MTBE. Certain of our subsidiaries used, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies seeking different remedies against us and many other defendants, including remedial activities, damages, attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation (MDL) in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. Eighty-eight of the cases have been settled or dismissed, and all of the settlements have been or are expected to be substantially funded by insurance. We have eleven remaining lawsuits, all pending in the MDL. Of these remaining lawsuits, it is likely that our insurers will assert denial of coverage on nine of the most-recently filed lawsuits. Based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us as well as availability of insurance coverages. Therefore, our costs and legal exposure related to the remaining lawsuits are not currently determinable.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. 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, 2011, we had approximately $40 million accrued, which has not been reduced by $3 million of related insurance receivables, for all of our outstanding legal proceedings.

Rates and Regulatory Matters

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

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates which would increase revenue by approximately $100 million annually over previously effective tariff rates. It is uncertain whether such an increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of a hearing in the rate case. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates of approximately $200 million annually over previously effective tariff rates. It is uncertain whether such an increase will be achieved in the context of any settlement between TGP and its customers or following the outcome of a hearing in the rate case. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

CIG Rate Case. In May 2011, Colorado Interstate Gas Company (CIG) reached a pre-filing settlement with all of its shippers of a rate case required under the terms of a previous settlement. CIG has filed the proposed settlement with the FERC which provides for CIG s current tariff rates to continue until its next general rate case which will be effective after October 1, 2014 but no later than October 1, 2016. At this time, the FERC has not ruled on that petition and the outcome of this matter is not 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, 2011, our accrual was approximately $170 million for environmental matters, which has not been reduced by $19 million for amounts to be paid directly under government sponsored programs or through contractual arrangements with third parties. Our accrual includes approximately $167 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $3 million for related environmental legal costs.

Our estimates of potential liability range from approximately $170 million to approximately $355 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, 2011	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 8	$ 12
Non-operating	149	307
Superfund	13	36
Total	$ 170	$ 355

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

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Superfund, or state equivalents for 28 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 2011, we estimate that our total remediation expenditures will be approximately $30 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $24 million in the aggregate for the remainder of 2011 through 2015, including capital expenditures associated with the impact of the Environmental Protection Agency rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

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

Guarantees and Other Contractual Commitments

Guarantees and Indemnifications. We have guarantees and indemnifications with a maximum stated value of approximately $0.8 billion, primarily related to indemnification arrangements associated with the sale of ANR Pipeline Company in 2007 and certain legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 7. 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, 2011, we have recorded obligations of $18 million related to our guarantee and indemnification arrangements. 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.

For a further discussion of our guarantees, indemnifications, purchase obligations, and other commercial commitments see our 2010 Annual Report on Form 10-K.

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9. Retirement Benefits

Components of Net Benefit Cost. The components of net benefit cost are as follows for the quarters and six months ended June 30:

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010	2011	2010	2011	2010
	(In millions)							
Service cost	$ 6	$ 4	$	$	$ 11	$ 9	$	$
Interest cost	27	29	7	9	53	57	15	17
Expected return on plan assets	(37)	(40)	(3)	(4)	(73)	(79)	(7)	(7)
Amortization of net actuarial loss (gain)	23	18	(1)	(1)	46	37	(1)	(2)
Amortization of prior service cost		1				1		
Net benefit cost	$ 19	$ 12	$ 3	$ 4	$ 37	$ 25	$ 7	$ 8

10. Equity and Preferred Stock of Subsidiaries

Convertible Perpetual Preferred Stock. In March 2011, we exercised our mandatory conversion right related to our \$750 million of convertible perpetual preferred stock. Upon conversion, holders of our convertible preferred stock received approximately 57.9 million shares of common stock (approximately 77.2295 shares of El Paso common stock for each share of preferred stock converted).

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, 2011	\$ 14	\$ 9
Amount paid in July 2011	\$ 8	\$
Declared in July 2011:		
Date of declaration	July 14, 2011	
Payable to shareholders on record	September 2, 2011	
Date payable	October 3, 2011	

Dividends on our common stock and convertible preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For 2011, 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 2010 Annual Report on Form 10-K.

Noncontrolling Interest in EPB. We are the general partner of EPB, a master limited partnership (MLP) formed in 2007. As of June 30, 2011, we own a 44 percent interest in EPB (2 percent general partner interest and a 42 percent limited partner interest). During the first half of 2011, we contributed the remaining 40 percent ownership interest in SNG and an additional 28 percent interest in CIG to EPB in exchange for approximately \$1.4 billion. EPB raised the funds for the acquisitions primarily through $948 million in proceeds from the issuance of 28.5 million common units and $444 million in borrowings under the EPPOC revolving credit facility. Our consolidated statement of equity for the six months ended June 30, 2011 reflects the issuance of the EPB common units as an increase of $610 million to noncontrolling interests and an increase of $338 million to El Paso Corporation s additional paid-in capital. Our net income attributable to El Paso Corporation, together with the increase in El Paso Corporation s additional paid-in capital for the six months ended June 30, 2011 totaled $662 million.

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

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To the extent that the consideration for the sales of assets to EPB is not in the form of additional equity in EPB, our interest in our assets becomes diluted over time. However our economic interest will benefit from the receipt of incentive distributions in accordance with the partnership agreement.

Our IDRs provide for the receipt of an increasing portion of quarterly distributions based on the level of distribution to all unitholders. We can elect to relinquish the right to receive incentive distribution payments and reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments would be set. We are currently entitled to receive the maximum level of incentive distributions.

Preferred Stock of Subsidiaries. During the first six months of 2011, our partner on our Ruby pipeline project, Global Infrastructure Partners (GIP), contributed an additional $30 million and as of June 30, 2011 had contributed $700 million, including approximately $555 million for a convertible preferred interest in Ruby Pipeline Holding Company, L.L.C. (Ruby) and $145 million for a convertible preferred equity interest in Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains). GIP receives a dividend at a 15 percent annual rate on its preferred interests in Cheyenne Plains payable quarterly. Effective in the third quarter of 2011, GIP will receive a dividend at a 13 percent annual rate on its convertible preferred interests in Ruby payable quarterly.

We paid preferred dividends of $5 million and $10 million on GIP s preferred interest in Cheyenne Plains for the quarters and six months ended June 30, 2011 and 2010. Also, for the quarter and six months ended June 30, 2011, we accrued $18 million and $35 million related to the return on GIP s preferred interest in Ruby. Both the preferred dividends and the return on GIP s preferred interests are reflected in net income attributable to noncontrolling interests on our income statement. GIP s preferred interests in Cheyenne Plains and Ruby, including accrued preferred returns, are classified between liabilities and equity on our balance sheet. For a further discussion of the Ruby transaction, see Note 12.

Net Income Attributable to Noncontrolling Interests. The components of net income attributable to noncontrolling interests on our statements of income are as follows for the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
EPB	$ 54	$ 24	$ 106	$ 50
Preferred Stock of Cheyenne Plains	5	5	10	10
Preferred Stock of Ruby	18		35	
Net income attributable to noncontrolling interests	$ 77	$ 29	$ 151	$ 60

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11. Business Segment Information

As of June 30, 2011, our business consists of the following segments: Pipelines, Exploration and Production, and Marketing. We also have other business and corporate activities. 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. A further discussion of each segment follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services. As of June 30, 2011, 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.

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

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

Other. Our other activities include our corporate general and administrative functions, midstream operations and miscellaneous businesses.

Beginning January 1, 2011, we use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 amounts have been conformed to reflect our current performance measure.

Below is a reconciliation of our Segment EBIT to our net income for the periods ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Segment EBIT	$ 616	$ 552	$ 1,011	$ 1,400
Interest and debt expense	(239)	(284)	(479)	(527)
Income tax expense	(38)	(82)	(57)	(268)
Net income	339	186	475	605
Net income attributable to noncontrolling interests	(77)	(29)	(151)	(60)
Net income attributable to El Paso Corporation	$ 262	$ 157	$ 324	$ 545

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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	Other	Eliminations	Total
			(In millions)			
Quarter Ended June 30, 2011						
Revenue from external customers	$ 684	$ 379(1)	$ 172	$ 1	$	$ 1,236
Intersegment revenue	38	156(1)	(192)	1	(3)	
Operation and maintenance	211	97	2	12	1	323
Depreciation, depletion and amortization	110	146		6		262
Earnings from unconsolidated affiliates	25	1		6		32
Segment EBIT	428	250	(21)	(41)(2)		616
Quarter Ended June 30, 2010						
Revenue from external customers	$ 668	$ 199(1)	$ 133	$ 18	$	$ 1,018
Intersegment revenue	12	170(1)	(181)	5	(6)	
Operation and maintenance	195	91	1	(2)		285
Depreciation, depletion and amortization	110	128		4		242
Earnings (losses) from unconsolidated affiliates	107(3)	(1)		5		111
Segment EBIT	472	103	(49)	26		552

(1) Revenues from external customers include gains of $132 million and $31 million for the quarters ended June 30, 2011 and 2010 related to our financial derivative contracts associated with our oil and natural gas production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(2) Includes loss on debt extinguishment of approximately $27 million primarily related to debt repurchases.

(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	Other	Eliminations	Total
			(In millions)			
Six Months Ended June 30, 2011						
Revenue from external customers	$ 1,387	$ 463(1)	$ 373	$ 2	$	$ 2,225
Intersegment revenue	88	322(1)	(405)	2	(7)	
Operation and maintenance	401	198	4	25		628
Depreciation, depletion and amortization	224	280		12		516
Earnings (losses) from unconsolidated affiliates	50	(1)		13		62
Segment EBIT	927	219	(35)	(100)(2)		1,011
Six Months Ended June 30, 2010						
Revenue from external customers	$ 1,392	$ 626(1)	$ 382	$ 19	$	$ 2,419
Intersegment revenue	25	390(1)	(411)	4	(8)	
Operation and maintenance	379	190	3	14		586
Depreciation, depletion and amortization	216	235		9		460
Earnings (losses) from unconsolidated affiliates	129(3)	(1)		11		139
Segment EBIT	924	493	(32)	15		1,400

(1) Revenues from external customers include gains of $23 million and $284 million for the six months ended June 30, 2011 and 2010 related to our financial derivative contracts associated with our oil and natural gas production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(2) Includes loss on debt extinguishment of approximately $68 million primarily related to debt repurchases.

(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, 2011	December 31, 2010

	(In millions)	
Pipelines	$ 20,824	$ 19,651
Exploration and Production	4,999	4,657
Marketing	210	222
Other	989	943
Total segment assets	27,022	25,473
Eliminations	(64)	(203)
Total consolidated assets	$ 26,958	$ 25,270

12. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby/Cheyenne Plains. As of June 30, 2011 GIP, our partner in the Ruby pipeline project, had contributed approximately $700 million in exchange for convertible preferred equity interests in Ruby and Cheyenne Plains. We currently consolidate Ruby and Cheyenne Plains as variable interest entities as we are the primary beneficiary of the entities that own the Ruby pipeline project and the Cheyenne Plains pipeline. GIP s preferred interests are classified between liabilities and equity on our balance sheet since the events that require redemption of those interests are not entirely within our control and are not certain to occur. GIP will hold its preferred interest in Cheyenne Plains until certain remaining customary conditions with respect to the operations of the Ruby pipeline are either satisfied or waived by our partner and lenders, at which time these interests will be transferred back to us in exchange for additional preferred interests in Ruby. GIP s preferred equity interest in Ruby is convertible at any time into common equity; however, it is subject to mandatory conversion to common equity upon the satisfaction of certain requirements, including Ruby entering into additional firm transportation agreements of 250 MMcf/d. Approximately 1.1 Bcf/d of the total design capacity of 1.5 Bcf/d on our Ruby pipeline is currently subscribed. Our ability to enter into additional firm transportation agreements will be based on future market conditions.

If the customary conditions described above are not satisfied or waived by December 2011, GIP has the option to convert its preferred interest in Cheyenne Plains to a common interest and/or be repaid in cash for its remaining investments in Cheyenne Plains and Ruby including a 15 percent annual return on these investments. 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.

Upon satisfaction or waiver of the conditions noted above, we will deconsolidate Ruby and reflect it as an equity method investment. Upon deconsolidation, we will be required to assess the impairment of our equity investment at fair value, which is a different model than we currently use while consolidated. Currently, we assess recoverability of the Ruby pipeline based on estimated undiscounted cash flows. As a result of assuming construction and cost overrun risk with the project, we anticipate that we will be required to record a non-cash loss on our investment in Ruby upon deconsolidation in an amount ranging from $300 million to $500 million based on our assessment of the estimated fair value of our investment in Ruby. The ultimate loss will be based on a number of factors, including actual market conditions at that time. For additional information on our Ruby pipeline project, see Note 10.

Accounts Receivable Sales Programs. We participate in accounts receivable sales programs where several of our pipeline subsidiaries sell receivables in their entirety to a third-party financial institution (through wholly-owned special purpose entities). The sale of these accounts receivable (which are short-term assets that generally settle within 60 days) qualify for sale accounting. The third party financial institution involved in these accounts receivable sales programs acquires interests in various financial assets and issues commercial paper to fund those acquisitions. We do not consolidate the third party financial institution because we do not have the power to control, direct, or exert significant influence over its overall activities since our receivables do not comprise a significant portion of its operations.

In connection with our accounts receivable sales, we receive a portion of the sales proceeds up front and receive an additional amount upon the collection of the underlying receivables (which we refer to as a deferred purchase price). Our ability to recover the deferred purchase price is based solely on the collection of the underlying receivables. The table below contains information related to our accounts receivable sales programs.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Accounts receivable sold to the third-party financial institution[1]	$ 597	$ 563	$ 1,204	$ 1,206
Cash received for accounts receivable sold under the programs	343	331	696	786
Deferred purchase price related to accounts receivable sold	254	232	508	420

Cash received related to the deferred purchase price	250	243	498	480
Amount paid in conjunction with terminated programs [2]				90

(1) During the quarters and six months ended June 30, 2011 and 2010, losses recognized on the sale of accounts receivable were immaterial.

(2) In January 2010, we terminated our previous accounts receivable sales programs and paid $90 million to acquire the related senior interests in certain receivables under those programs. See our 2010 Annual Report on Form 10-K for further information.

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	June 30, 2011	December 31, 2010
	(In millions)	
Accounts receivable sold and held by third-party financial institution	$ 217	$ 210
Uncollected deferred purchase price related to accounts receivable sold [(1)]	99	89

(1) Initially recorded at an amount which approximates its fair value as a Level 2 measurement

The deferred purchase price related to the accounts receivable sold is reflected as other accounts receivable on our balance sheet. Because the cash received up front and the deferred purchase price relate to the sale or ultimate collection of the underlying receivables, and are not subject to significant other risks given their short term nature, we reflect all cash flows under the accounts receivable sales programs as operating cash flows on our statement of cash flows. Under the accounts receivable sales programs, we service the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the quarters and six months ended June 30, 2011 and 2010.

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

Our net investments in and earnings (losses) from our unconsolidated affiliates are as follows as of June 30, 2011 and December 31, 2010 and for the quarters and six months ended June 30:

	Investment		Earnings (Losses) from Unconsolidated Affiliates			
			Quarters Ended June 30,		Six Months Ended June 30,	
	June 30, 2011	December 31, 2010	2011	2010	2011	2010
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Four Star [1]	$ 366	$ 393	$ 1	$ (1)	$ (1)	$ (1)
Citrus[2]	872	822	24	25	49	40
Gulf LNG[3]	259	266				
Bolivia-to-Brazil Pipeline	103	104	1	4	3	9
Other[4]	89	88	6	83	11	91
Total	$ 1,689	$ 1,673	$ 32	$ 111	$ 62	$ 139

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star Oil & Gas Company (Four Star) of $9 million for each of the quarters ended June 30, 2011 and 2010 and $18 million and $19 million for the six months ended June 30, 2011 and 2010.

(2) As of June 30, 2011, we had outstanding receivables of approximately $72 million, included in other long term assets, related to a promissory note from Citrus whereby we will lend up to $150 million.

(3) As of June 30, 2011 and December 31, 2010, we had outstanding advances and receivables of $144 million and $85 million, included in other long term assets, related to our investment in Gulf LNG.

(4) Includes our investment in Gasoductos de Chihuahua for the quarter and six months ended June 30, 2010. 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.

Below is summarized financial information of our proportionate share of the operating results of our unconsolidated affiliates for the quarters and six months ended June 30, 2011 and 2010.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$ 169	$ 128	$ 297	$ 260
Operating expenses	70	65	137	138
Net income	34	41	74	79

We received distributions and dividends from our unconsolidated affiliates of $19 million and $21 million for the quarters ended June 30, 2011 and 2010 and $31 million and $36 million for the six months ended June 30, 2011 and 2010. Our transactions with unconsolidated affiliates were not material to our operating results during the quarters and six months ended June 30, 2011 and 2010.

Other Investment-Related Matters. We currently have outstanding disputes and other matters related to an investment in two Brazilian power plant facilities (Manaus/Rio Negro) formerly owned by us. We have filed lawsuits to collect amounts due to us (approximately $74 million of Brazilian reais-denominated accounts receivable) by the plants power purchaser, which are also guaranteed by the purchaser s parent, Eletrobras, Brazil s state-owned utility. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable. Absent resolution of these matters through settlement, we anticipate that the ultimate resolution will likely occur through legal proceedings in the Brazilian courts. We believe the receivables are collectible and therefore have not established an allowance against the receivables owed. We have reviewed our obligations under the power purchase agreements and have accrued what we believe is an appropriate amount in relation to the asserted counterclaims. We believe the remaining counterclaims are without merit. Based on the anticipated timing of the resolution of the legal proceedings, we have classified our accounts receivable and the accrual for the counterclaims as a non-current asset and liability in our financial statements.

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Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately $85 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser has been indemnifying our project companies for these ICMS taxes, along with related interest and penalties. In the third quarter of 2010, a court hearing the Rio Negro case seized funds from certain of El Paso s Rio Negro bank accounts in partial satisfaction of and as security for this potential tax liability. In order to prevent collection efforts by the tax authorities for this matter against our project companies, security must be provided for the potential tax liability to the court s satisfaction. Although the power purchaser and the taxing authorities could not previously agree upon the security to be provided, it is our understanding that they have now agreed upon the posting of shares in the power purchaser s parent as security. The court hearing the Rio Negro case has now accepted these shares as security. We are awaiting a similar decision by the court hearing the Manaus case. Upon acceptance by the courts of the shares as security, the power purchaser will then ask the court to vacate any orders encumbering our bank accounts and other assets and to refund to us any cash previously seized. Until this tax matter is fully resolved, our ability to collect amounts due to us from the power purchaser could be impacted. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser s parent. Based on our assessment, we have not established any accruals for this matter.

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

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

The information contained in Item 2 updates, and should be read in conjunction with, information disclosed in our 2010 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 2011, our Segment EBIT was $1,011 million, compared with $1,400 million for the same period in 2010. Pipeline Segment EBIT year-to-date continued to benefit from expansion projects placed in service in 2010 and 2011 and from the allowance for funds used during construction (AFUDC) related primarily to our Ruby pipeline project and several expansion projects not yet in service, partially offset by lower reservation revenues on our EPNG system. Our Exploration and Production Segment EBIT year-to-date decreased by approximately $274 million largely due to mark-to-market impacts of our financial derivatives, despite increases in production volumes year over year. Also impacting our results during these periods were approximately $68 million in losses associated with the repurchase of approximately $350 million of our debt in 2011 and a gain of approximately $80 million in the second quarter of 2010 related to the sale of our Mexican pipeline assets. Our quarterly results are discussed in the individual segment results that follow.

We continue to work towards completion of our backlog of pipeline expansion projects, and as of June 30, 2011, the Florida Gas Transmission (FGT) Phase VIII Expansion, Phases I and II of the SNG South System III Expansion and Phase II of the SNG Southeast Supply Header projects were placed in service on time and on budget. In July 2011, our Ruby pipeline project was also placed in service four months later than planned due to permitting and weather delays and approximately $0.65 billion over the original $3.0 billion budget. In our exploration and production business, our continued 2011 capital focus in our Haynesville, Altamont, Eagle Ford, and Wolfcamp areas have provided us with greater exposure to both oil and natural gas liquids opportunities. Finally, in our midstream business, we continue to seek out opportunities that focus on synergies with our pipeline and/or exploration and production businesses, funding these projects in a manner that is consistent with our long-term goal of improving our balance sheet. For the remainder of 2011, we expect that our pipeline and exploration and production operations will provide a strong base of earnings and operating cash flow.

On May 24, 2011, we announced that our Board of Directors had granted initial approval of a plan to separate the Company into two publicly traded businesses by the end of 2011. The plan calls for a tax-free spin-off of our exploration and production business and related activities into a new publicly traded company separate from El Paso Corporation. The planned separation is subject to market, regulatory, tax and final approval by our Board of Directors and other customary conditions.

From a liquidity perspective, as of June 30, 2011 we had approximately $2.7 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby). During the first six months of 2011, we generated operating cash flow of approximately $1.0 billion and spent approximately $2.0 billion primarily in our capital programs. During the first half of 2011, we (i) refinanced approximately $2.25 billion of our revolving credit facilities (excluding the $1.0 billion EPPOC revolving credit facility also refinanced in May 2011) to extend these maturities to 2016 and (ii) we received approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our MLP which funded the acquisitions primarily through the issuance of common units and debt. As of June 30, 2011, our remaining 2011 capital expenditures are approximately $1.6 billion and our remaining 2011 debt maturities are approximately $0.4 billion, which we will repay as they mature. Additionally, in July 2011, our unsecured $500 million credit facility matured. As further described in *Liquidity and Capital Resources,* we believe we are well positioned in 2011 to meet our obligations as well as continue with our efforts to strengthen our balance sheet. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements and to address any changes in the financial and commodity markets and our businesses.

As part of the plan to separate the Company into two publicly traded businesses by the end of 2011, we plan to have our exploration and production business issue approximately $2.0 billion to $2.25 billion of debt, the net proceeds from which will be used to repay revolver borrowings, satisfy intercompany debt and pay a dividend to El Paso. We expect to use such proceeds as part of our ongoing liability management program.

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Segment Results

As of June 30, 2011, our business consists of the following segments: Pipelines, Exploration and Production, and Marketing. We also have other business and corporate activities that include midstream and other miscellaneous businesses. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies.

Beginning January 1, 2011, we use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 amounts have been conformed to reflect our current performance measure.

Below is a reconciliation of our Segment EBIT to our consolidated net income for the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
Segment				
Pipelines	$ 428	$ 472	$ 927	$ 924
Exploration and Production	250	103	219	493
Marketing	(21)	(49)	(35)	(32)
Other	(41)	26	(100)	15
Segment EBIT	616	552	1,011	1,400
Interest and debt expense	(239)	(284)	(479)	(527)
Income tax expense	(38)	(82)	(57)	(268)
Net income	339	186	475	605
Net income attributable to noncontrolling interests	(77)	(29)	(151)	(60)
Net income attributable to El Paso Corporation	$ 262	$ 157	$ 324	$ 545

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Pipelines Segment

Overview and Operating Results. Our Pipelines Segment EBIT for the quarter and six months ended June 30, 2011 benefited primarily from (i) several expansion projects placed in service in 2010 and 2011; (ii) an increase in AFUDC on expansion projects that were not yet in service during the quarter, principally the Ruby pipeline project; (iii) higher rates on our TGP system effective June 1, 2011 due to its November 2010 rate case; and (iv) higher operating revenues due to BG LNG Services LLC s (BG) election not to continue with Phase B of SLNG s Elba Expansion III project. Partially offsetting these factors was a decline in revenues from our EPNG system due to lower demand and firm transportation commitments in 2011 and an $80 million gain on the sale of our Mexican pipeline and compression assets in 2010. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting Segment EBIT for the quarters and six months ended June 30, 2011 compared with the same periods in 2010, or that could potentially impact Segment EBIT in future periods.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions, except for volumes)			
Operating revenues	$ 722	$ 680	$ 1,475	$ 1,417
Operating expenses	(397)	(370)	(775)	(726)
Operating income	325	310	700	691
Other income, net	103	162	227	233
Segment EBIT	$ 428	$ 472	$ 927	$ 924
Throughput volumes (BBtu/d)[(1)(2)]	17,042	17,150	17,549	17,968

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

(2) Throughput volumes for the quarter and six months ended June 30, 2010 include 746 BBtu/d and 744 BBtu/d related to our Mexican pipeline assets which were sold in 2010.

	Quarter Ended June 30, 2011 Variance				Six Months Ended June 30, 2011 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 21	$ (5)	$ 21	$ 37	$ 62	$ (14)	$ 70	$ 118
Reservation and usage revenues	11	(4)		7	(15)	(7)		(22)
Gas not used in operations and revaluations	(7)			(7)		(1)		(1)
Operating and general and administrative expense		(18)		(18)		(34)		(34)

Asset sale/write down			(80)	(80)		10	(80)	(70)
Project cancellation payment	17	(3)		14	17	(3)		14
Other[(1)]		3		3	(6)		4	(2)
Total impact on Segment EBIT	$ 42	$ (27)	$ (59)	$ (44)	$ 58	$ (49)	$ (6)	$ 3

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

Expansions. During 2011, we benefited from increased reservation revenues due to placing a number of expansion projects in service in 2010 and 2011, including the (i) WIC System Expansion; (ii) Phase A of both the SLNG Elba Expansion III and Elba Express Pipeline Expansion projects; (iii) CIG Raton 2010 Expansion; (iv) Phases I and II of the SNG South System III Expansion; and (v) Phase II of the Southeast Supply Header project.

We capitalize a carrying cost (AFUDC) on funds related to our construction of long-lived assets. During the quarter and six months ended June 30, 2011, we benefited from an increase in other income of approximately $21 million and $70 million associated with the equity portion of AFUDC on our expansion projects. This increase is primarily due to our Ruby pipeline project. In April 2011, Ruby filed an amendment of its certificate requesting an increase in maximum initial recourse rates to reflect the new estimate of expected construction costs and limiting total AFUDC accruals to the total amounts included in the original certificate order. In June 2011, Ruby ceased recording AFUDC based on the proposed amendment of the certificate which was subsequently approved by the FERC in July 2011. Accordingly, our AFUDC will decline in future periods.

In July 2011, our Ruby pipeline project was placed in service. We currently consolidate Ruby in our financial statements and reflect 100 percent of the capital cost on our balance sheet. Once certain remaining customary conditions of our partner and lenders are satisfied or waived, we will deconsolidate Ruby. We anticipate receiving these consents or waivers within 60 to 90 days after Ruby s in service date of July 28, 2011. Upon deconsolidation, we will present Ruby in our financial statements as an equity method investment and will be required to assess the impairment of our equity investment at fair value, which is a different model than we currently use while consolidated. Currently, we assess recoverability of the Ruby pipeline project based on estimated undiscounted cash flows. As a result of assuming construction and cost overrun risk with the project, we anticipate that we will be required to record a non-cash loss on our investment in Ruby upon deconsolidation in an amount ranging from $300 million to $500 million based on our assessment of the estimated fair value of our investment in Ruby. The ultimate loss will be based on a number of factors, including actual market conditions at that time.

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We expect our Segment EBIT contribution from Ruby will decline in the second half of 2011 once we no longer record AFUDC income and, upon deconsolidation, begin reflecting equity earnings in Segment EBIT after reductions for interest expense and the preferred return to our partner. Our level of earnings ultimately will depend on the level of contracted customer capacity and our ability to market unsubscribed firm capacity. Approximately 1.1 Bcf/d of the total design capacity of 1.5 Bcf/d is currently subscribed. Based on current market conditions, we do not expect significant additional long-term firm capacity subscriptions in the near term.

For additional information on our Ruby pipeline project, see Item 1, Financial Statements, Notes 10 and 12.

Reservation and Usage Revenues. Our reservation and usage revenues for the quarter and six months ended June 30, 2011 were impacted by a number of factors, including regulatory action, competition, weather and changes in supply and demand. On our TGP system, revenues increased by $18 million and $16 million for the quarter and six months ended June 30, 2011 due to higher rates which became effective June 1, 2011 as a result of its November 2010 rate case. The decline of $3 million and $24 million for the quarter and six months ended June 30, 2011 on our EPNG system was primarily driven by high gas storage levels and increased hydroelectric generation in its California market, the nonrenewal of certain expiring contracts and the sale of open capacity at lower prices due to lower basis differentials. On our SNG system, nonrenewal of contracts decreased our Segment EBIT by $2 million and $4 million during the quarter and six months ended June 30, 2011 compared to the same periods in 2010. Additionally, our SNG usage revenues were lower by $1 million and $4 million primarily due to record weather conditions in the Southeast during 2010 as compared to 2011.

Gas Not Used in Operations and Other Natural Gas Sales. Gas not used in operations results in revenues to us, which we recognize when the volumes are retained, valued at market price specified in our tariff. During the quarter ended June 30, 2011, our Segment EBIT, primarily on our TGP system, was favorably impacted by $4 million due to higher sales prices realized on operational gas sales, offset by the impact of lower retained fuel volumes in excess of fuel used in operations of $11 million. The decrease in volumes not used in operations was primarily due to the implementation of a fuel volume tracker effective June 1, 2011 as part of TGP s rate case filed with the FERC. Our Segment EBIT for the six months ended June 30, 2011 was primarily unchanged by the impact of operational gas sales and fuel volumes in excess of fuel used in operations compared to the same period in 2010. The impact of lower retained volumes for the six months ended June 30, 2011 was offset by higher realized prices on increased operational sales volumes. The financial impacts to our Segment EBIT associated with these operational activities on our TGP system will be largely eliminated as a result of the tracker.

Operating and General and Administrative Expenses. During the quarter and six months ended June 30, 2011, our operating and general and administrative expenses were higher compared to the same periods in 2010 primarily due to higher benefits, payroll, and contractor costs of $7 million and $28 million and higher property tax assessments of $5 million and $7 million on our TGP system.

Asset Sale/Write Down. 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 market conditions.

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Project Cancellation Payment. During the quarter and six months ended June 30, 2011, we recognized operating revenues of $17 million related to BG s election not to continue with Phase B of our SLNG Elba Expansion III project, partially offset by $3 million for certain project development costs incurred in conjunction with this expansion project which were written off.

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, several of our pipelines have projected upcoming rate actions with anticipated effective dates through 2013 as further described below.

EPNG Rate Case. In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates which would increase revenue by approximately $100 million annually over previously effective tariff rates. It is uncertain whether such an increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of a hearing in the rate case. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates of approximately $200 million annually over previously effective tariff rates. It is uncertain whether such an increase will be achieved in the context of any settlement between TGP and its customers or following the outcome of a hearing in the rate case. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

CIG Rate Case. In May 2011, CIG reached a pre-filing settlement with all of its shippers of a rate case required under the terms of a previous settlement. CIG has filed the proposed settlement with the FERC which provides for CIG s current tariff rates to continue until its next general rate case which will be effective after October 1, 2014 but no later than October 1, 2016. At this time, the FERC has not ruled on that petition and the outcome of this matter is not determinable.

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Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our oil and natural gas exploration and production activities. The success of this segment is driven by the ability to locate and develop economic oil and natural gas 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 2010 Annual Report on Form 10-K.

Our profitability and performance is impacted by, among other factors, 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. We may also be impacted by the effect of hurricanes and other weather events, or the effects of domestic or international regulatory or other actions in response to events outside of our control (e.g. oil spills). To the extent possible, we attempt to mitigate certain of these risks through actions, such as entering into contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

In May 2011, we announced that our Board of Directors had granted initial approval to spin-off the exploration and production business into a new publicly traded company separate from El Paso Corporation by the end of 2011. The spin-off is subject to market, regulatory, tax and final approval by our Board of Directors and other customary conditions.

Significant Operational Factors Affecting the Periods Ended June 30, 2011 and 2010

Volumes. Our volumes by commodity for the six months ended June 30 were as follows:

	2011	**2010**
Natural Gas (MMcf/d)		
Consolidated volumes	658	622
Unconsolidated affiliate volumes	47	46
Total Combined	705	668
Oil and condensate (MBbls/d)		
Consolidated volumes	14	13
Unconsolidated affiliate volumes	1	1
Total Combined	15	14
NGL (MBbls/d)		
Consolidated volumes	3	4
Unconsolidated affiliate volumes	2	2
Total Combined	5	6

Our average daily production volumes for the six months ended June 30, 2011 was 822 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 six months ended June 30:

	2011	2010
	MMcfe/d	
United States		
Central	415	330
Western	154	156
Southern [(1)]	157	205
International		
Brazil	34	31
Total Consolidated	760	722
Unconsolidated affiliate	62	62
Total Combined	822	784

(1) In 2011, our Gulf Coast division was renamed the Southern division, and we made minor changes to the properties contained within our various domestic operating divisions. Divisional amounts for prior periods have been adjusted to reflect these changes.

Central division Our 2011 Central division production volumes continued to increase as a result of our successful drilling programs in the Haynesville shale. At June 30, 2011, we had 83 operated wells and our total production was approximately 260 MMcfe/d related to our Haynesville program.

Western division Our 2011 Western division production volumes are flat compared to 2010 due to natural declines in the Rockies offset by increased production volumes in Altamont. As of June 30, 2011 we had 251 operated wells and our total production was approximately 51 MMcfe/d related to our Altamont program.

Southern division Our 2011 Southern division production volumes decreased primarily due to natural declines and lower levels of drilling activity in the Texas Gulf Coast and Gulf of Mexico areas. In this division, we continue to focus on increasing our Eagle Ford shale activity, where in 2011 we have successfully drilled 28 additional wells, for a total of 48 wells. These wells are located principally in the liquids rich area of the Eagle Ford shale. As of June 30, 2011, our total production was approximately 37 MMcfe/d related to our Eagle Ford program. Additional Eagle Ford production is currently constrained due to infrastructure limitations which we expect will be resolved in the second half of 2011. We also continue to assess our Wolfcamp shale area, having drilled seven wells during 2011.

International Our 2011 production volumes in Brazil increased due to production from our Camarupim Field. We continue to work with the operator, Petrobras, in this field where a fourth well is expected to begin production later in 2011. We also continue the process of obtaining regulatory and environmental approvals for the Pinauna Field in the Camamu Basin that are required in order to enter the next phase of development. During the quarter ended June 30, 2011, we released $44 million of our unevaluated capitalized costs related to the ES-5 block to our Brazilian full cost pool upon the completion of our evaluation of an exploratory well drilled in 2009. As of June 30, 2011, we have approximately $142 million and $70 million of remaining unevaluated capitalized costs in Brazil and Egypt, respectively. During the second half of the year we expect to complete a test of an exploratory well drilled in 2010 in Brazil and further evaluate the commerciality of areas within our South Alamein and South Mariut blocks in Egypt through the drilling of additional wells. Depending on the results of our activities we could incur ceiling test charges in the future.

Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas 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 our Exploration and Production segment, however, this measure may not be comparable to those used by other companies. During the six months ended June 30, 2011, cash operating costs per unit decreased to \$1.80/Mcfe as compared to \$1.83/Mcfe during the same period in 2010.

Capital Expenditures. Our total oil and natural gas capital expenditures were \$736 million for the six months ended June 30, 2011, of which \$724 million were domestic capital expenditures.

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Capital expenditures for the six months ended June 30, 2011 and rig count by core program as of June 30, 2011 were:

	Capital Expenditures (In millions)	Rig Count
Haynesville	$ 197	4
Altamont	74	3
Eagle Ford	275	4
Wolfcamp	70	2
Other programs	120	1
Total capital expenditures	$ 736	14

Outlook for 2011

For the full year we currently expect the following on a worldwide basis:

- Capital expenditures, excluding acquisitions, of approximately $1.6 billion. Of this total, we expect to spend approximately $1.5 billion on our domestic program (more than half of which is expected to be allocated to oil and liquids programs) and approximately $0.1 billion in Brazil and Egypt.
- Average daily equivalent total production volumes for the year of approximately 830 MMcfe/d to 860 MMcfe/d, which includes approximately 60 MMcfe/d from Four Star.
- Average daily oil production volumes for the year of approximately 18.5 MBbls/d to 20.5 MBbls/d, including Four Star.
- Average cash operating costs between $1.70/Mcfe and $1.85/Mcfe for the year; and
- Depreciation, depletion and amortization rate between $2.05/Mcfe and $2.15/Mcfe.

Price Risk Management Activities

We enter into derivative contracts on our oil and natural gas production to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge all of our price risks, this strategy only partially reduces our commodity price exposure. Our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company. During the first six months of 2011, approximately 86 percent of our natural gas production and 100 percent of our crude oil production were economically hedged at average floor prices of $5.71 per MMBtu and $85.99 per barrel, respectively.

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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, 2011.

		2011		2012		2013	
		Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Natural Gas							
Fixed Price Swaps		86	$ 5.87	105	$ 6.01		$
Ceilings		9	$ 7.29		$		$
Floors		9	$ 6.00		$		$
Basis Swaps [2]							
Texas Gulf Coast		17	$ (0.13)		$		$
Raton		11	$ (0.25)		$		$
Oil							
Fixed Price Swaps		1,012	$ 87.54	640	$ 100.13		$
Ceilings			$	1,464	$ 95.00	2,920	$ 96.88
Three Way Collars	Ceiling	1,840	$ 94.27	5,764	$ 114.16	1,552	$ 128.34
Three Way Collars	Floors[3]	1,840	$ 85.14	5,764	$ 92.54	1,552	$ 100.00

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

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

(3) If market prices settle at or below $65.00, $67.54 and $75.00 for the years 2011, 2012 and 2013, respectively, our three way collars-floors effectively lock-in a cash settlement of $20.14 for 2011 and $25.00 for 2012 and 2013 above that market price.

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,	
	2011	2010	2011	2010
	(In millions)			
Physical sales				
Natural gas	$ 257	$ 228	$ 497	$ 516
Oil and condensate	133	89	236	164
NGL	13	16	28	34
Total physical sales	403	333	761	714
Realized and unrealized gains on financial derivatives	132	31	23	284
Other revenues		5	1	18
Total operating revenues	535	369	785	1,016

Operating expenses				
Cost of products		5		15
Transportation costs	18	18	38	36
Production costs	70	64	143	133
Depreciation, depletion and amortization	146	128	280	235
General and administrative expenses	48	47	98	96
Ceiling test charges				2
Other	3	5	6	9
Total operating expenses	285	267	565	526
Operating income	250	102	220	490
Other (expense) income [(1)]		1	(1)	3
Segment EBIT	$ 250	$ 103	$ 219	$ 493

(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.

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, oil and condensate and NGL as well as (ii) average realized prices including 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,	
	2011	2010	2011	2010
Volumes				
Natural gas (MMcf)				
Consolidated volumes	59,791	56,361	119,052	112,508
Unconsolidated affiliate volumes	4,301	4,144	8,554	8,358
Oil and condensate (MBbls)				
Consolidated volumes	1,349	1,245	2,543	2,243
Unconsolidated affiliate volumes	76	108	159	198
NGL (MBbls)				
Consolidated volumes	245	387	538	791
Unconsolidated affiliate volumes	128	123	280	279
Equivalent volumes				
Consolidated MMcfe	69,356	66,154	137,543	130,711
Unconsolidated affiliate MMcfe	5,526	5,529	11,186	11,219
Total combined MMcfe	74,882	71,683	148,729	141,930
Consolidated MMcfe/d	762	727	760	722
Unconsolidated affiliate MMcfe/d	61	61	62	62
Total combined MMcfe/d	823	788	822	784
Consolidated prices and costs per unit				
Natural gas ($/Mcf)				
Average realized price on physical sales	$ 4.29	$ 4.05	$ 4.18	$ 4.59
Average realized price, including financial derivative settlements (1)(2)	$ 5.44	$ 5.86	$ 5.44	$ 5.95
Average transportation costs	$ 0.28	$ 0.31	$ 0.30	$ 0.30
Oil and condensate ($/Bbl)				
Average realized price on physical sales	$ 98.46	$ 71.54	$ 92.74	$ 73.08
Average realized price, including financial derivative settlements(1)(2)	$ 91.30	$ 71.04	$ 88.67	$ 72.03
Average transportation costs	$ 0.06	$ 0.06	$ 0.06	$ 0.06
NGL ($/Bbl)				
Average realized price on physical sales	$ 54.85	$ 40.10	$ 52.41	$ 42.43
Average transportation costs	$ 4.73	$ 2.57	$ 4.88	$ 2.68
Production costs and other cash operating costs ($/Mcfe)				
Average lease operating expenses	$ 0.71	$ 0.67	$ 0.73	$ 0.71
Average production taxes(3)	0.31	0.30	0.31	0.31

Total production costs	$	1.02	$	0.97	$	1.04	$	1.02
Average general and administrative expenses		0.69		0.72		0.71		0.74
Average taxes, other than production and income taxes		0.04		0.08		0.05		0.07
Total cash operating costs	$	1.75	$	1.77	$	1.80	$	1.83
Depreciation, depletion and amortization ($/Mcfe)[4]	$	2.11	$	1.92	$	2.04	$	1.79

(1) We had no cash premiums related to natural gas and oil derivatives settled during the quarter and six months ended June 30, 2011. Premiums 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 oil derivatives settled during the quarter and six months ended June 30, 2010.

(2) The quarters ended June 30, 2011 and 2010, include approximately $68 million and $102 million of cash receipts for settlements of natural gas derivative contracts and approximately $9 million and $1 million of cash paid for settlements of crude oil derivative contracts. The six months ended June 30, 2011 and 2010, include approximately $150 million and $153 million of cash receipts for settlements of natural gas derivative contracts and approximately $10 million and $2 million of cash paid for settlements of crude oil derivative contracts.

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

(4) Includes $0.06 and $0.07 per Mcfe for the quarters ended June 30, 2011 and 2010, respectively, and $0.06 per Mcfe for each of the six months ended June 30, 2011 and 2010 related to accretion expense on asset retirement obligations.

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Quarter and Six Months Ended June 30, 2011 Compared with Quarter and Six Months Ended June 30, 2010

Our Segment EBIT for the quarter ended June 30, 2011 increased $147 million and for the six months ended June 30, 2011 decreased $274 million as compared to the same periods in 2010. The table below shows the significant variances of our financial results for the quarter and six months ended June 30, 2011 as compared to the same periods in 2010:

	Quarter Ended June 30, 2011 Variance				Six Months Ended June 30, 2011 Variance			
	Operating Revenue	Operating Expense	Other	Segment EBIT	Operating Revenue	Operating Expense	Other	Segment EBIT
	Favorable/(Unfavorable) (In millions)							
Physical sales								
Natural gas								
Higher (lower) realized prices in 2011	$ 15	$	$	$ 15	$ (49)	$	$	$ (49)
Higher volumes in 2011	14			14	30			30
Oil and condensate								
Higher realized prices in 2011	36			36	50			50
Higher volumes in 2011	8			8	22			22
NGL								
Higher realized prices in 2011	3			3	5			5
Lower volumes in 2011	(6)			(6)	(11)			(11)
Realized and unrealized gains (losses) on financial derivatives	101			101	(261)			(261)
Other revenues	(5)			(5)	(17)			(17)
Depreciation, depletion and amortization expense								
Higher depletion rate in 2011		(13)		(13)		(34)		(34)
Higher production volumes in 2011		(5)		(5)		(11)		(11)
Production costs								
Higher lease operating expenses in 2011		(5)		(5)		(7)		(7)
Higher production taxes in 2011		(1)		(1)		(3)		(3)

General and administrative expenses		(1)		(1)		(2)		(2)
Ceiling test charges						2		2
Earnings from investment in Four Star			2	2				
Other		7	(3)	4		16	(4)	12
Total Variances	$ 166	$ (18)	$ (1)	$ 147	$ (231)	$ (39)	$ (4)	$ (274)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the quarter and six months ended June 30, 2011, our revenues increased primarily as a result of higher oil and natural gas volumes and higher oil and condensate prices. During the quarter ended June 30, 2011, our revenues also benefited from higher natural gas prices. The higher volumes are due to our focus on our core programs in Haynesville and Eagle Ford shales.

Realized and unrealized gains on financial derivatives. During the quarter and six months ended June 30, 2011, we recognized net gains of $132 million and $23 million compared to net gains of $31 million and $284 million during the same periods in 2010. Gains or losses each period are due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

Depreciation, depletion and amortization expense. During the quarter and six months ended June 30, 2011, our depreciation, depletion and amortization expense increased as a result of a higher depletion rate and higher production volumes compared with the same periods in 2010. Our depreciation, depletion and amortization rate is higher due to our focus on more liquids rich programs and we expect the rate to continue to increase during the second half of the year.

General and administrative expenses. During the six months ended June 30, 2011, our general and administrative expenses increased compared to the same period in 2010, due to severance costs related to an office closure, offset by a lower corporate overhead allocation and lower labor-related costs. The impact of these severance costs was approximately $5 million, or $0.04 per Mcfe on total cash operating costs.

Production costs. During the quarter and six months ended June 30, 2011, our production costs increased as compared to the same periods in 2010 primarily due to higher lease operating expenses in our Western division as a result of higher subsurface maintenance costs and higher production taxes associated with higher volumes.

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Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the first quarter of 2010, we recorded a non-cash ceiling test charge in our Egyptian full cost pool of $2 million as a result of the relinquishment of approximately 30 percent of our acreage in the South Mariut block.

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Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s oil and natural gas production and to manage El Paso s overall price risk. In addition, we continue to manage and liquidate certain legacy contracts. 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 2010 Annual Report on Form 10-K.

Natural gas transportation-related contracts. The impact of these accrual-based contracts is based on our ability to use or remarket the contracted pipeline capacity and the amount of production from our Exploration and Production segment. As of June 30, 2011, these contracts require us to pay demand charges of $19 million for the remainder of 2011 and an average of $40 million per year between 2012 and 2015.

Legacy natural gas and power contracts. As of June 30, 2011, these contracts include (i) long-term accrual based supply contracts, including transportation expenses, that obligate us to deliver natural gas to specified power plants and (ii) power contracts in the PJM region through 2016, which we mark-to-market in our results. These contracts are expected to have minimal future impact on our earnings as we have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

Operating Results

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Income (Loss)				
Contracts Related to Legacy Trading Operations:				
Natural gas transportation-related contracts:				
Demand charges	$ (12)	$ (10)	$ (22)	$ (19)
Settlements, net of termination payments	(2)	5	(3)	16
Changes in fair value of other natural gas derivative contracts	(2)	(4)	(2)	(5)
Changes in fair value of power contracts	(4)	(39)	(5)	(21)
Total revenues	(20)	(48)	(32)	(29)
Operating expenses	(2)	(1)	(4)	(3)
Operating loss	$ (22)	$ (49)	$ (36)	$ (32)
Other income, net	1		1	
Segment EBIT	$ (21)	$ (49)	$ (35)	$ (32)

During the quarter and six months ended June 30, 2011, our results were primarily impacted by a $7 million and $22 million loss related to settlements on an affiliated fuel supply agreement. This agreement terminated in June 2011. Our results for the quarter and six months ended June 30, 2010 were primarily impacted by changes in the fair value of our legacy power contracts in PJM prior to the execution of additional offsetting positions.

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Other Activities

Our other activities include our corporate general and administrative functions, our midstream operations and other miscellaneous businesses.

Midstream. As of June 30, 2011, our midstream operations consist primarily of wholly-owned assets in the Haynesville area in north Louisiana and the Eagle Ford area in south Texas, in addition to an equity investment in a joint venture that owns the Altamont natural gas gathering system and processing plant in the Uintah basin of Utah. The joint venture is currently working to expand the Altamont system, and we and our joint venture partner have each committed to make up to $500 million of future capital contributions to the joint venture for additional midstream projects to be acquired or developed by the joint venture. Our midstream business is also evaluating several larger scale projects in the Eagle Ford area, in the emerging shale plays in the Rockies, west Texas and the northeast United States including the Marcellus shale in Pennsylvania as further discussed below.

In late June 2011, we announced an open season, which will close on September 15, 2011, to elicit binding commitments from prospective shippers interested in ethane transportation on our new proposed Marcellus Ethane Pipeline System (MEPS) designed to provide transportation service from West Virginia and Pennsylvania Marcellus shale supply areas to markets in Louisiana or Texas. We have entered into a Memorandum of Understanding with a wholly-owned subsidiary of Spectra Energy Corp. to pursue joint development of this project.

For the full year 2011, we expect to make capital expenditures and equity investments totaling approximately $100 million related to the midstream projects discussed above.

The following is a summary of significant items impacting the Segment EBIT in our other activities for the quarters and six months ended June 30:

	Quarters Ended June 30,		**Six Months Ended June 30,**	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Income (Loss)				
Loss on debt extinguishment	$ (27)	$	$ (68)	$
Change in environmental, legal and other reserves	(13)	10	(24)	2
Midstream	4	3	6	3
Other	(5)	13	(14)	10
Total Segment EBIT	$ (41)	$ 26	$ (100)	$ 15

Loss on Debt Extinguishment. During 2011, we incurred losses primarily related to the repurchase of approximately $350 million of our senior unsecured notes. In July 2011, we repurchased an additional $274 million of debt under our early tender offer and anticipate spending up to an additional $438 million in August 2011 to buy back additional debt. In conjunction with these transactions we anticipate recording losses of approximately $100 million during the third quarter of 2011.

Environmental, Legal and Other Reserves. We have a number of pending litigation matters and reserves related to our historical business operations that affect our results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may continue to impact our future results. Our results for both the quarter and six months ended June 30, 2011 and 2010 were impacted by adjustments to certain legacy indemnifications and other environmental matters, primarily related an indemnification on which our liability fluctuates with ammonia prices and a non-operating chemical plant.

Other. Other consists primarily of benefit costs associated with certain of our postretirement benefit plans. For more information about our postretirement benefit plans and related benefit costs, see Item 1, Financial Statements, Note 9. During both the quarter and six months ended June 30, 2010, our Segment EBIT was favorably impacted by equity earnings primarily from legacy power investments and the refund of certain insurance premiums on legacy activities.

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Interest and Debt Expense

Our interest and debt expense decreased during the quarter and six months ended June 30, 2011 as compared to the same periods in 2010 primarily associated with the exchange or repurchase of approximately $1.4 billion of debt in 2010 and 2011 with rates from 7 percent to 12 percent. Interest savings associated with our liability management transactions have been partially offset by interest costs on new borrowings. During 2011, we also had higher capitalized AFUDC related to debt on our Ruby pipeline project.

Income Taxes

	Quarters Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions, except for rates)			
Income taxes	$ 38	$ 82	$ 57	$ 268
Effective tax rate	10%	31%	11%	31%

Our effective tax rate for the quarter and six months ended June 30, 2011 was favorably impacted by the resolution of certain tax matters. Absent this item, the effective tax rate for the quarter and six months ended June 30, 2011 would have been 14 percent and 16 percent. Our effective tax rate is expected to remain well below the statutory rate due to the growth of earnings attributable to noncontrolling interests of EPB.

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

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item 1, Financial Statements, Note 8, which is incorporated herein by reference and our 2010 Annual Report on Form 10-K.

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Liquidity and Capital Resources

Available Liquidity and Liquidity Outlook for 2011. As of June 30, 2011, we had approximately $2.7 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby). The increase in our available liquidity during the first six months of 2011 was primarily the result of receiving approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our MLP which funded the acquisitions primarily through the issuance of common units and debt. During the first half of 2011, we refinanced approximately $2.25 billion of our revolving credit facilities (excluding the $1.0 billion EPPOC revolving credit facility also refinanced in May 2011). In July 2011, our $500 million unsecured credit facility matured.

Our planned 2011 capital expenditures will allow us to place a substantial portion of our pipeline backlog in service by the end of 2011 while continuing to support our exploration and production strategy. Our cash capital expenditures for the six months ended June 30, 2011, and the amount of cash we expect to spend for the remainder of 2011 to grow and maintain our businesses are as follows:

	Six Months Ended June 30, 2011	2011 Remaining	Total
	(In billions)		
Pipelines			
Maintenance	$ 0.2	$ 0.1	$ 0.3
Growth(1)	1.1	0.4	1.5
Exploration and Production	0.6	1.0	1.6
Other(2)	0.1	0.1	0.2
	$ 2.0	$ 1.6	$ 3.6

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

(2) Includes $100 million related to our midstream business.

In July 2011, the Ruby pipeline project was placed in service. GIP, our 50 percent partner, has provided $700 million to support the project. Our obligation to repay these amounts, if required, is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in our MLP. Upon making certain permitting representations, and obtaining consents and/or waivers of certain customary conditions (that we anticipate within 60 to 90 days after Ruby s in service date of July 28, 2011), our Ruby project financing obligations will become non-recourse to us and GIP will no longer be able to require us to repay its investment. As of July 31, 2011, we also had $100 million outstanding ($170 million as of June 30, 2011) in letters of credit related to Ruby. For a further description of this project and our agreement with GIP, see our 2010 Annual Report on Form 10-K and Note 12.

We expect our current liquidity sources and operating cash flow will be sufficient to fund our estimated 2011 capital program. As of June 30, 2011, we also have remaining 2011 debt maturities of approximately $0.4 billion ($0.6 billion through June 30, 2012) which we will repay as they mature. As a result of our current available liquidity, hedging program in place on our oil and natural gas production, completed and targeted non-core asset sales and planned future actions (including continuing with our MLP drop down strategy as markets permit), we believe we are well positioned to meet our obligations as well as continue with our efforts to strengthen our balance sheet. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements as well as address further changes in the financial and commodity markets.

There are a number of factors that could impact our plans, including our ability to access the financial markets to if these 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, 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 2011, we generated operating cash flow of approximately $1.0 billion primarily from our pipeline and exploration and production operations. We also generated approximately $3.0 billion through the refinancing and issuance of debt and an additional $0.9 billion from the issuance of MLP common units. We used cash flow generated from these operating and financing activities to fund $2.0 billion in capital expenditures under our capital programs and to make $2.9 billion in repayments under our various credit facilities and other debt obligations. For the six months ended June 30, 2011, our cash flows are summarized as follows:

	2011 (In billions)
Cash Flow from Operations	
Operating activities	
Net income	$ 0.5
Other income adjustments	0.5
Total cash flow from operations	$ 1.0
Other Cash Inflows	
Financing activities	
Net proceeds from the issuance of long-term debt	3.0
Net proceeds from the issuance of noncontrolling interests	0.9
Total other cash inflows	$ 3.9
Cash Outflows	
Investing activities	
Capital expenditures	2.0
Other	0.1
	$ 2.1
Financing activities	
Payments to retire long-term debt and other financing obligations	2.9
Total cash outflows	$ 5.0
Net change in cash	$ (0.1)

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and should be read in conjunction with the information disclosed in our 2010 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 have been no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2010 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

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 reflect 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, 2011	$ 126	$ (76)	$ (202)	$ 315	$ 189
December 31, 2010	$ 237	$ 33	$ (204)	$ 434	$ 197
Other commodity-based derivatives net assets (liabilities)					
June 30, 2011	$ (372)	$ (371)	$ 1	$ (374)	$ (2)
December 31, 2010	$ (423)	$ (422)	$ 1	$ (426)	$ (3)

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2011, 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, 2011.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the second quarter of 2011 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 8, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2010 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 2010 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. Below are additional risk factors as a result of the recent announcement to separate into two publicly traded businesses.

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Risks Related to Proposed Separation Plan

If our plan to separate our exploration and production business is delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On May 24, 2011, we announced that our Board of Directors had granted initial approval of a plan to separate the Company into two publicly traded businesses by the end of 2011. The plan calls for a tax-free spin-off of our exploration and production business and related activities into a new publicly traded company separate from El Paso Corporation. The completion and timing of the proposed transaction is dependent on a number of factors including the macroeconomic environment, credit markets, equity markets, the receipt of a tax opinion from counsel, the receipt of an Internal Revenue Service tax ruling, finalization of the capital structure of the new company, completion of the required Securities and Exchange Commission filings, separation agreements between the two companies, final approval from our Board of Directors and other customary approvals. We may not complete the transaction by the end of 2011 or on the terms that we originally announced or we may not complete the transaction at all. If the transaction is not completed or if it is delayed, our stock price may decline and our growth potential may not be enhanced.

If our plan to separate our exploration and production business is completed, it may not achieve the intended results.

If the separation of our exploration and production business is completed, we may not realize the benefits that were expected due to various factors, including the failure of the businesses to operate successfully as independent entities, the reduction in scope and scale as a result of the separation of the businesses, the failure of the two companies to grow their businesses as expected, the incurrence of new debt obligations in our exploration and production business, the incurrence of additional costs of the companies to operate separately, the failure to adequately develop systems and controls in the exploration and production business as a standalone entity following the spin-off, potential future disputes and liabilities between the companies as a result of the separation and risks associated with our ability to retain key employees of the separated companies. Any such difficulties could have an adverse effect on our business, results of operations and financial condition.

The spin-off could result in substantial tax liability.

We have requested a private letter ruling from the Internal Revenue Service (IRS) substantially to the effect that, for U.S. federal income tax purposes, the spin-off and certain related transactions will qualify under Sections 355 and/or 368 of the U.S. Internal Revenue Code of 1986, as amended (the Code). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. The private letter ruling will be based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also intend to obtain an opinion of outside counsel, substantially to the effect that, for U.S. federal income tax purposes, the spin-off and certain related transactions will qualify under Sections 355 and 368 of the Code. The opinion will rely on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion will not be binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail. As a result, there is a risk that the spin-off could ultimately be taxable to us and each stockholder of El Paso common stock who receives shares of the exploration and production company formed in conjunction with the spin-off.

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

None.

Item 3. Defaults Upon Senior Securities

None.

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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 5, 2011	/s/ John R. Sult John R. Sult Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: August 5, 2011	/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
10.1	Fourth Amended and Restated Credit Agreement, dated as of May 27, 2011, among El Paso Corporation, El Paso Natural Gas Company and Tennessee Gas Pipeline Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent for the Lenders (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.2	Fourth Amended and Restated Security Agreement, dated as of May 27, 2011, among El Paso Corporation, the persons referred to therein as Pipeline Company Borrowers, the persons referred to therein as Subsidiary Grantors, and JPMorgan Chase Bank, N.A., as Collateral Agent and Depository Bank (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.3	Third Amended and Restated Credit Agreement, dated as of June 2, 2011, among El Paso Exploration and Production Company and El Paso E&P Company, L.P., as Borrowers and BNP Paribas, as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 8, 2011).
*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.