EL PASO CORP/DE
Form 10-Q
May 09, 2011

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 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	**76-0568816**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas**	**77002**
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 420-2600
Internet Website: www.elpaso.com

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

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

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

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

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

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

Common stock, par value $3 per share. Shares outstanding on May 2, 2011: 768,967,144

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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
MMBbls	= million barrels
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/or subsidiaries.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarter Ended March 31, 2011	Quarter Ended March 31, 2010
Operating revenues	$ 989	$ 1,401
Operating expenses		
Cost of products and services	47	53
Operation and maintenance	305	301
Depreciation, depletion and amortization	254	218
Taxes, other than income taxes	76	69
	682	641
Operating income	307	760
Earnings from unconsolidated affiliates	30	28
Loss on debt extinguishment	(41)	
Other income, net	99	60
Interest and debt expense	(240)	(243)
Income before income taxes	155	605
Income tax expense	19	186
Net income	136	419
Net income attributable to noncontrolling interests	(74)	(31)
Net income attributable to El Paso Corporation	62	388
Preferred stock dividends of El Paso Corporation		(9)
Net income attributable to El Paso Corporation s common stockholders	$ 62	$ 379
Basic earnings per common share		
Net income attributable to El Paso Corporation s common stockholders	$ 0.09	$ 0.54
Diluted earnings per common share		
Net income attributable to El Paso Corporation s common stockholders	$ 0.08	$ 0.51
Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.01

See accompanying notes.

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

	March 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents (includes $48 in 2011 and $31 in 2010 held by variable interest entities)	$ 242	$ 347
Accounts and notes receivable		
Customer, net of allowance of $4 in 2011 and $4 in 2010	368	333
Affiliates	9	7
Other	159	160
Materials and supplies	166	169
Assets from price risk management activities	154	265
Deferred income taxes	189	165
Other	104	106
Total current assets	1,391	1,552
Property, plant and equipment, at cost		
Pipelines (includes $3,702 in 2011 and $3,232 in 2010 held by variable interest entities)	22,893	22,385
Oil and natural gas properties, at full cost	22,024	21,692
Other	438	416
	45,355	44,493
Less accumulated depreciation, depletion and amortization	23,565	23,421
Total property, plant and equipment, net	21,790	21,072
Other long-term assets		
Investments in unconsolidated affiliates	1,683	1,673
Assets from price risk management activities	32	61
Other	961	912
	2,676	2,646
Total assets	$ 25,857	$ 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)

	March 31, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 452	$ 610
Affiliates	11	9
Other	420	386
Short-term financing obligations, including current maturities	495	489
Liabilities from price risk management activities	188	176
Asset retirement obligations	64	63
Accrued interest	247	202
Other	533	630
Total current liabilities	2,410	2,565
Long-term financing obligations, less current maturities	13,566	13,517
Other long-term liabilities		
Liabilities from price risk management activities	401	397
Deferred income taxes	628	568
Other	1,450	1,461
	2,479	2,426
Commitments and contingencies (Note 7)		
Preferred stock of subsidiaries	745	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 778,840,616 shares in 2011 and 719,743,724 shares in 2010	2,337	2,159
Additional paid-in capital	5,246	4,484
Accumulated deficit	(2,372)	(2,434)
Accumulated other comprehensive loss	(729)	(751)

Treasury stock (at cost); 14,475,623 shares in 2011 and 15,492,605 shares in 2010	(272)	(291)
Total El Paso Corporation stockholders equity	4,210	3,917
Noncontrolling interests	2,447	2,147
Total equity	6,657	6,064
Total liabilities and equity	$ 25,857	$ 25,270

See accompanying notes.

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

	Quarter Ended March 31, 2011	Quarter Ended March 31, 2010
Cash flows from operating activities		
Net income	$ 136	$ 419
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	254	218
Deferred income tax expense	26	194
Earnings from unconsolidated affiliates, adjusted for cash distributions	(18)	(13)
Loss on debt extinguishment	41	
Other non-cash income items	(64)	(4)
Asset and liability changes	156	(336)
Net cash provided by operating activities	531	478
Cash flows from investing activities		
Capital expenditures	(1,089)	(741)
Other		(6)
Net cash used in investing activities	(1,089)	(747)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	806	775
Payments to retire long-term debt and other financing obligations	(794)	(617)
Net proceeds from issuance of noncontrolling interests	457	231
Distributions to noncontrolling interest holders	(39)	(19)
Net proceeds from issuance of preferred stock of subsidiary	30	
Distributions to holders of preferred stock of subsidiary	(5)	(5)
Dividends paid	(16)	(16)
Other	14	
Net cash provided by financing activities	453	349
Change in cash and cash equivalents	(105)	80
Cash and cash equivalents		
Beginning of period	347	635
End of period	$ 242	$ 715

See accompanying notes.

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

	Quarter Ended March 31, 2011	Quarter Ended March 31, 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	4	
Balance at end of period	2,337	2,148
Additional paid-in capital:		
Balance at beginning of period	4,484	4,501
Conversion of preferred stock	576	
Dividends	(7)	(16)
Issuances of noncontrolling interests (Note 9)	170	
Other, including stock-based compensation	23	12
Balance at end of period	5,246	4,497
Accumulated deficit:		
Balance at beginning of period	(2,434)	(3,192)
Net income attributable to El Paso Corporation	62	388
Balance at end of period	(2,372)	(2,804)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(751)	(718)
Other comprehensive income	22	12
Balance at end of period	(729)	(706)
Treasury stock, at cost:		
Balance at beginning of period	(291)	(283)
Stock-based and other compensation	19	(1)
Balance at end of period	(272)	(284)

Total El Paso Corporation stockholders equity at end of period	4,210	3,601
Noncontrolling interests:		
Balance at beginning of period	2,147	785
Issuances of noncontrolling interests (Note 9)	287	231
Distributions to noncontrolling interests	(39)	(19)
Net income attributable to noncontrolling interests (Note 9)	52	26
Balance at end of period	2,447	1,023
Total equity at end of period	$ 6,657	$ 4,624

See accompanying notes.

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

	Quarter Ended March 31, 2011	Quarter Ended March 31, 2010
Net income	$ 136	$ 419
Pension and postretirement obligations:		
Reclassification of actuarial gains during period (net of income taxes of $7 in 2011 and $6 in 2010)	16	13
Other (net of income taxes of $3 in 2011 and 2010)	6	(1)
Other comprehensive income	22	12
Comprehensive income	158	431
Comprehensive income attributable to noncontrolling interests	(74)	(31)
Comprehensive income attributable to El Paso Corporation	$ 84	$ 400

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 March 31, 2011, and for the quarters ended March 31, 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 Form 10-K. In our opinion, we have made adjustments, all of which are of a normal, recurring nature to fairly present our interim period results. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation, none of which impacted our reported net income (loss) or stockholders equity. Additionally, our statement of cash flows for the quarter ended March 31, 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.

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 March 31, 2011.

2. Other Income, Net

The following are the components of other income and other expense for the quarters ended March 31:

	2011	2010
	(In millions)	
Other Income		
Allowance for equity funds used during construction	$ 97	$ 50
Other	7	14
Total	104	64
Other Expense		
Other	5	4
Total	5	4
Other income, net	$ 99	$ 60

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.

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3. Income Taxes

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

	2011	2010
	(In millions, except rates)	
Income tax expense	$ 19	$ 186
Effective tax rate	12%	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 the item occurs. Changes in tax laws or rates are recorded in the period of enactment. Our effective tax rate is affected by items such as income attributable to nontaxable noncontrolling interests, dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the effect of state income taxes (net of federal income tax effects), and the effect of foreign income which can be taxed at different rates.

During the first quarter of 2011, our effective tax rate was lower than the statutory rate primarily due to the benefit to our anticipated annual effective tax rate of income attributable to nontaxable noncontrolling interests and dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends. In addition, our effective tax rate for the first quarter of 2011 was favorably impacted by the resolution of several tax matters and earned state tax credits. During the first quarter of 2010, our effective tax rate was lower than the statutory rate primarily due to income attributable to nontaxable noncontrolling interests partially offset by $18 million of additional deferred income tax expense from healthcare legislation enacted in March 2010 which reduces the tax deduction for retiree prescription drug expenses to the extent they are reimbursed under the Medicare subsidy program.

4. Earnings Per Share

Basic and diluted earnings per common share were as follows for the quarters ended March 31:

	2011		2010	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 62	$ 62	$ 388	$ 388
Preferred stock dividends of El Paso Corporation			(9)	
Interest on preferred securities				3
Net income attributable to El Paso Corporation s common stockholders	$ 62	$ 62	$ 379	$ 391
Weighted average common shares outstanding	714	714	696	696
Effect of dilutive securities:				
Options and restricted stock		10		6
Convertible preferred stock		44		58
Trust preferred securities				8
Weighted average common shares outstanding and dilutive securities	714	768	696	768
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.09	$ 0.08	$ 0.54	$ 0.51

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 for the periods presented consist of employee stock options, restricted stock, convertible preferred stock and trust preferred securities. In March 2011, we converted our preferred stock to common stock as further described in Note 9. For the quarters ended March 31, 2011 and 2010, certain of our employee stock options were antidilutive. Additionally, for the quarter ended March 31, 2011, our trust preferred securities were antidilutive.

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5. Financial Instruments

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

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$14,061	$15,343	$14,006	$14,686
Marketable securities in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(344)	(344)	(186)	(186)
Interest rate derivatives	(59)	(59)	(61)	(61)
Other	(8)	(8)	(11)	(11)

As of March 31, 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 March 31, 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 natural gas and oil production on 253 TBtu and 283 TBtu of natural gas and 15,777 MBbl and 12,240 MBbl of oil. None of these contracts are designated as accounting hedges.

Other Commodity-Based Derivatives. As of March 31, 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 March 31, 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 March 31, 2011 relates to debt associated with our Ruby pipeline project that begin accruing interest on July 1, 2011 and have termination dates ranging from June 2013 to June 2017. These termination dates correspond to the estimated principal outstanding on the Ruby debt over the term of these swaps. For a further discussion of our Ruby financing, see Note 6.

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 March 31, 2011 and December 31, 2010, these interest rate swaps converted the interest rate on approximately $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 ended March 31, 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 March 31, 2011 and December 31, 2010, cash collateral held was not material. The following table presents the fair value of our financial instruments at March 31, 2011 and December 31, 2010 (in millions).

	March 31, 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	$	$ 307	$	$ 307	$	$ 373	$	$ 373
Other natural gas derivatives		146	18	164		139	18	157
Power-related derivatives			26	26			31	31
Total commodity-based derivative assets		453	44	497		512	49	561
Interest rate derivatives designated as hedges								
Fair value hedges		7		7		8		8
Impact of master netting arrangements		(306)	(12)	(318)		(229)	(14)	(243)
Total price risk management assets	$	$ 154	$ 32	$ 186	$	$ 291	$ 35	$ 326
Marketable securities in non-qualified compensation plans	20			20	20			20
Total net assets	$ 20	$ 154	$ 32	$ 206	$ 20	$ 291	$ 35	$ 346
Liabilities								
Commodity-based derivatives								
	$	$ (257)	$	$ (257)	$	$ (136)	$	$ (136)

Production-related oil and natural gas derivatives								
Other natural gas derivatives		(167)	(76)	(243)		(162)	(90)	(252)
Power-related derivatives			(341)	(341)			(359)	(359)
Total commodity-based derivative liabilities		(424)	(417)	(841)		(298)	(449)	(747)
Interest rate derivatives designated as hedges								
Cash flow hedges		(66)		(66)		(69)		(69)
Impact of master netting arrangements		306	12	318		229	14	243
Total price risk management liabilities	$	$ (184)	$ (405)	$ (589)	$	$ (138)	$ (435)	$ (573)
Other			(11)	(11)			(12)	(12)
Total net liabilities	$	$ (184)	$ (416)	$ (600)	$	$ (138)	$ (447)	$ (585)
Total	$ 20	$ (30)	$ (384)	$ (394)	$ 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.

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter ended March 31, 2011 (in millions):

	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues(1)	Change in Fair Value Reflected in Operating Expenses(2)	Settlements_	Balance at End of Period
Assets	$ 35	$ (3)	$	$	$ 32
Liabilities	(447)	2	(1)	30	(416)
Total	$ (412)	$ (1)	$ (1)	$ 30	$ (384)

(1) Includes approximately $4 million of net losses that had not been realized through settlements as of March 31, 2011.

(2) Includes approximately $1 million of net losses that had not been realized through settlements as of March 31, 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 ended March 31:

	2011			2010		
	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)
			(In millions)			
Production-related derivatives	$ (109)	$	$ 3	$ 253	$	$ 3
Other natural gas and power derivatives not designated as hedges	(1)			17		
Total interest rate derivatives		4	3		5	(1)
Total	$ (110)	$ 4	$ 6	$ 270	$ 5	$ 2

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6. Debt, Other Financing Obligations and Other Credit Facilities

	March 31, 2011	December 31, 2010
	(In millions)	
Short-term financing obligations, including current maturities	$ 495	$ 489
Long-term financing obligations	13,566	13,517
Total	$ 14,061	$ 14,006

Changes in Financing Obligations. During the quarter ended March 31, 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
El Paso Exploration and Production Company (EPEP) revolving credit facility	variable	200	200
El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC) revolving credit facility	variable	215	215
Increases through March 31, 2011		$ 806	$ 806
Repayments, repurchases, and other			
EPEP revolving credit facility	variable	$ (400)	$ (400)
El Paso revolving credit facility	variable	(100)	(100)
EPPOC revolving credit facility	variable	(107)	(107)
El Paso notes due 2012 through 2025	7.25%-12.00%	(140)	(181)
Other	various	(4)	(6)
Decreases through March 31, 2011		$ (751)	$ (794)

Subsequent to March 31, 2011, our overall debt has increased by approximately $500 million due to incremental borrowings under our revolving credit facilities. This increase was partially offset by a reduction in letters of credit issued under these facilities related to our Ruby pipeline project.

Repurchase of Senior Notes. In March 2011, we repurchased $148 million of notes and recorded a loss on debt extinguishment of approximately $41 million. In April 2011, we repurchased an additional $153 million of notes and will record a loss of approximately $19 million in the second quarter of 2011.

Credit Facilities/Letters of Credit. We have various credit facilities in place which allow us to borrow funds or issue letters of credit. During the first quarter of 2011, we increased the total letter of credit capacity under certain existing letter of credit facilities by $125 million with a weighted average fixed facility fee of 1.95 percent and maturities ranging from March 2013 to September 2014. As of March 31, 2011, the aggregate amount outstanding under all of our credit facilities was $0.2 billion (excluding $0.4 billion outstanding on the EPPOC $750 million revolving credit facility) and $1.1 billion of letters of credit and surety bonds issued, including $0.4 billion related to our price risk management activities. Our total available capacity under all of our facilities was approximately $2.6 billion as of March 31, 2011 (not including capacity available under the EPPOC $750 million revolving credit facility and our Ruby project financing).

The availability of borrowings under our credit agreements and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. There have been no significant changes to our restrictive covenants, and as of March 31, 2011, we were in compliance with all of our debt covenants. For a further discussion of our credit facilities and restrictive covenants, see our 2010 Annual Report on Form 10-K.

Ruby Pipeline Financing. During 2010, we entered into a seven-year amortizing $1.5 billion financing facility for our Ruby pipeline project (see Note 11) that requires principal payments at various dates through June 2017. As of March 31, 2011, we have utilized substantially all of the capacity under this facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance $700 million of the facility by the end of year four. If we do not refinance $700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that begin in July 2011 and convert the floating LIBOR interest rate to fixed interest rates on approximately $1.1 billion of total borrowings under this agreement.

We have provided a contingent completion and cost-overrun guarantee to the Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, as of March 31, 2011, we have $350 million outstanding in letters of credit to cover anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender s engineer in subsequent months, additional collateral may be required to be issued pursuant to the Ruby financing agreements.

7. 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. While some of the cases have been settled or dismissed, several of the cases are in various stages of pre-trial or appellate proceedings as further described in our 2010 Annual report on Form 10-K. 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-seven of the cases have been settled or dismissed, with all of the settlements being substantially funded by insurance. We have twelve remaining lawsuits, which consist of ten cases that are pending in the MDL and two cases that are pending in state courts. Of these remaining lawsuits, it is likely that our insurers will assert denial of coverage on nine of the most-recently filed lawsuits. Although damages in excess of two billion dollars have been alleged in total against all defendants in some of the remaining cases, based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us as well as availability of insurance coverages. Therefore, our costs and legal exposure related to 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 March 31, 2011, we had approximately $50 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 uncontested partial offer of settlement which increased EPNG s base tariff rates, effective January 1, 2009. As part of the settlement, EPNG made refunds to its customers in 2010. The settlement resolved all but four issues in the proceeding. In January 2011, the Presiding Administrative Law Judge issued a decision that for the most part found against EPNG on the four issues. EPNG will appeal those decisions to the FERC and may also seek review of any of the FERC s decisions to the U.S. Court of Appeals. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate based on the expected final outcome.

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

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates, including a proposed change in its rate structure. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not determinable.

CIG Rate Case. In February 2011, the FERC approved an amendment of CIG s 2006 rate case settlement allowing the effective date of a required new rate case to be moved to December 1, 2011. In April 2011, CIG filed a second petition to amend the effective date of a required new rate case to be moved to February 1, 2012 to allow CIG and its shippers the opportunity to reach a settlement of the rate proceeding before it is formally filed with the FERC. The FERC has not ruled on that petition. At this time, the outcome of the pre-filing settlement negotiations and the outcome of the upcoming general rate case, in the event pre-filing settlement cannot be reached, are uncertain.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at current and former operating sites. At March 31, 2011, our accrual was approximately $168 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 $165 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 $168 million to approximately $352 million. Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	March 31, 2011	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 8	$ 12
Non-operating	146	303
Superfund	14	37
Total	$ 168	$ 352

Superfund Matters. Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as

Superfund, or state equivalents for 30 active sites. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

For 2011, we estimate that our total remediation expenditures will be approximately $40 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 $27 million in the aggregate for the remainder of 2011 through 2015, including capital expenditures associated with the impact of the Environmental Protection Agency (EPA) rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

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

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 6. We are unable to estimate a maximum exposure of our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of March 31, 2011, we have recorded obligations of $17 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.

8. Retirement Benefits

Components of Net Benefit Cost. The components of net benefit cost are as follows for the quarters ended March 31:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In millions)			
Service cost	$ 5	$ 5	$	$
Interest cost	26	28	8	8
Expected return on plan assets	(36)	(39)	(4)	(3)
Amortization of net actuarial loss (gain)	23	19		(1)
Net benefit cost	$ 18	$ 13	$ 4	$ 4

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9. Equity and Preferred Stock of Subsidiaries

Convertible Perpetual Preferred Stock. On March 11, 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 March 31, 2011	$ 7	$ 9
Amount paid in April 2011	$ 7	
Declared in April 2011:		
Date of declaration	April 1, 2011	
Payable to shareholders on record	June 3, 2011	
Date payable	July 1, 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. We expect dividends paid in 2011 on our common stock 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 March 31, 2011, we hold a 2 percent general partner interest and a 45 percent limited partner interest in the partnership. 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.

During the first quarter of 2011, EPB issued 13.8 million common units for $457 million in conjunction with the contribution of an additional 25 percent ownership interest in Southern Natural Gas (SNG). While we still control EPB, as a result of this unit issuance our total ownership percentage in EPB (including our general partner interest) decreased from approximately 51 percent to 47 percent. Our consolidated statement of equity for the quarter ended March 31, 2011 reflects the issuance of the EPB common units as an increase of $287 million to noncontrolling interests and $170 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 quarter ended March 31, 2011 totaled $232 million.

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.

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Preferred Stock of Subsidiaries. During the quarter ended March 31, 2011, our partner on our Ruby pipeline project, Global Infrastructure Partners (GIP), contributed an additional $30 million and as of March 31, 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 earns a 15 percent dividend on its preferred interests in Cheyenne Plains. GIP will earn a 13 percent return on its convertible preferred interests in Ruby beginning on the earlier of the date the pipeline project is placed in service or August 2011. We paid preferred dividends of $5 million on GIP s preferred interest in Cheyenne Plains for the quarters ended March 31, 2011 and 2010. Also, for the quarter ended March 31, 2011, we recorded $17 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 are classified between liabilities and equity on our balance sheet. For a further discussion of the Ruby transaction, see Note 11.

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 ended March 31:

	2011	2010
	(In millions)	
EPB	$ 52	$ 26
Preferred Stock of Cheyenne Plains	5	5
Preferred Stock of Ruby	17	
Net income attributable to noncontrolling interests	$ 74	$ 31

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10. Business Segment Information

As of March 31, 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, primarily in the U.S. As of March 31, 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, one of which is under construction.

Exploration and Production. Our Exploration and Production segment is engaged in the exploration for and the acquisition, development and production of 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 other 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 March 31:

	2011	2010
	(In millions)	
Segment EBIT	$ 395	$ 848
Interest and debt expense	(240)	(243)
Income tax expense	(19)	(186)
Net income	136	419
Net income attributable to noncontrolling interests	(74)	(31)
Net income attributable to El Paso Corporation	$ 62	$ 388

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The following table reflects our segment results for the quarters ended March 31:

	Segments					
	Pipelines	Exploration and Production	Marketing	Other	Eliminations	Total
			(In millions)			
2011						
Revenue from external customers	$703	$ 84(1)	$ 201	$ 1	$	$ 989
Intersegment revenue	50	166(1)	(213)	1	(4)	
Operation and maintenance	190	101	2	13	(1)	305
Depreciation, depletion and amortization	114	134		6		254
Earnings (losses) from unconsolidated affiliates	25	(2)		7		30
Segment EBIT	499	(31)	(14)	(59)		395
2010						
Revenue from external customers	$724	$ 427(1)	$ 249	$ 1	$	$1,401
Intersegment revenue	13	220(1)	(230)		(3)	
Operation and maintenance	184	99	2	16		301
Depreciation, depletion and amortization	106	107		5		218
Earnings from unconsolidated affiliates	22			6		28
Segment EBIT	452	390	17	(11)		848

(1) Revenues from external customers include losses of $109 million and gains of $253 million for the quarters ended March 31, 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.

Total assets by segment are presented below:

	March 31, 2011	December 31, 2010
	(In millions)	
Pipelines	$ 20,189	$ 19,651
Exploration and Production	4,735	4,657
Marketing	210	222
Other	896	943
Total segment assets	26,030	25,473
Eliminations	(173)	(203)

Total consolidated assets	$ 25,857	$ 25,270

11. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby/Cheyenne Plains. As of March 31, 2011 GIP, our partner in the Ruby pipeline project, had contributed approximately $700 million in exchange for convertible preferred equity interests (see Note 9) in Ruby and Cheyenne Plains. We consolidate Ruby and Cheyenne Plains as variable interest entities as we are the primary beneficiary of these entities that own the Ruby pipeline project and the Cheyenne Plains pipeline. GIP s contributions are classified between liabilities and equity on our balance sheet since the events that require redemption of the preferred interests are not entirely within our control and are not certain to occur. GIP will hold its interest in Cheyenne Plains until certain conditions are satisfied including placing the Ruby pipeline project in service by the end of November 2011. Should this not occur, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining investments in Cheyenne Plains and Ruby including a 15 percent return on its investments in Cheyenne Plains and Ruby. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in EPB. If all conditions to closing are satisfied or waived, GIP would own a 50 percent preferred equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. Additionally, GIP has the right to convert its preferred equity in Ruby to common equity in Ruby at any time.

Accounts Receivable Sales Program. 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 program.

	Quarter Ended March 31,	
	2011	**2010**
	(In billions)	
Accounts receivable sold to the third-party financial institution[(1)]	$0.6	$0.6
Cash received for accounts receivable sold under the program	0.4	0.5
Deferred purchase price related to accounts receivable sold	0.2	0.1
Cash received related to the deferred purchase price	0.2	0.2
Amount paid in conjunction with terminated programs [(2)]		0.1

(1) During the quarters ended March 31, 2011 and 2010, losses recognized on the sale of accounts receivable were immaterial.

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

	March 31, 2011	**December 31, 2010**
	(In billions)	
Accounts receivable sold and held by third-party financial institution	$0.2	$ 0.2
Uncollected deferred purchase price related to accounts receivable sold [(1)]	0.1	0.1

(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 ended March 31, 2011 and 2010.

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12. 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 March 31, 2011 and December 31, 2010 and for the quarters ended March 31:

	Investment		Earnings (Losses) from Unconsolidated Affiliates	
	March 31, 2011	December 31, 2010	Quarter Ended March 31, 2011	2010
	(In millions)		(In millions)	
Net Investment and Earnings (Losses)				
Four Star [1]	$ 381	$ 393	$ (2)	$
Citrus[2]	847	822	25	15
Gulf LNG[3]	267	266		
Bolivia-to-Brazil Pipeline	106	104	2	5
Other	82	88	5	8
Total	$ 1,683	$ 1,673	$ 30	$ 28

(1) Our amortization of purchase cost in excess of the underlying net assets of Four Star was $9 million and $10 million for the quarters ended March 31, 2011 and 2010.

(2) As of March 31, 2011, we had outstanding receivables of approximately $13 million, not included above, related to a promissory note from Citrus whereby we will lend up to $150 million. During April 2011, Citrus drew an additional $12 million under the note.

(3) As of March 31, 2011 and December 31, 2010, we had outstanding advances and receivables of $88 million and $85 million, not included above, related to our investment in Gulf LNG. These amounts include interest on the related advances and receivables.

	Quarter Ended March 31, 2011	2010
	(In millions)	
Summarized Financial Information		
Operating results data:		
Operating revenues	$ 128	$ 132
Operating expenses	67	73
Net income	40	38

We received distributions and dividends from our unconsolidated affiliates of approximately $12 million and $15 million for the quarters ended March 31, 2011 and 2010. Our transactions with unconsolidated affiliates were not material during the quarters ended March 31, 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 $71 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. We have not established an allowance against the receivables owed and have accrued what we believe is an appropriate amount in relation to the asserted counterclaims.

Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately $82 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser must indemnify our project companies for these ICMS taxes, along with related interest and penalties, and has therefore been defending the projects against this lawsuit. In order to prevent further collection efforts by the tax authorities for this matter, security must be provided for the potential tax liability to the court s satisfaction. The tax authorities and court rejected certain assets pledged by the power purchaser, and during the third quarter of 2010 the tax courts blocked certain of El Paso s bank accounts associated with the Rio Negro power plant in order to obtain this security. The power purchaser has appealed the court s decision. The power purchaser s parent subsequently offered to pledge other assets acceptable to the tax authorities and a decision by the court whether to approve these assets is pending. If the court approves, then the power purchaser will ask the court to vacate any orders encumbering our bank accounts and other assets. Until this tax matter is 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.

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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 quarter ended March 31, 2011, our Segment EBIT was $395 million, compared with $848 million for the same period in 2010. In 2011, Pipeline Segment EBIT increased slightly over 2010 to approximately $499 million for the quarter benefiting from expansion projects placed in service in 2010 and from the allowance for funds used during construction (AFUDC) related to pipeline expansion projects not yet in service (including Ruby); partially offset by lower reservation revenues on our EPNG system. Our Exploration and Production Segment EBIT decreased by approximately $421 million largely due to mark-to-market impacts on our financial derivatives, despite increases in production volumes quarter over quarter. During the first quarter of 2011, we also incurred approximately $41 million in losses associated with the repurchase of debt. We continue to work towards completion of our backlog of pipeline expansion projects, and in April, the Florida Gas Transmission (FGT) Phase VIII Expansion was placed in service on time and on budget. In our exploration and production business, our continued 2011 capital focus is in our Haynesville, Altamont, Eagle Ford, and Wolfcamp areas which provide us 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, including the evaluation of additional partnership opportunities on our projects. 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. Our operating and financial results and outlook are further discussed in the individual segment results that follow.

From a liquidity perspective, as of March 31, 2011, we had approximately $2.8 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby). During the first quarter of 2011, we generated operating cash flow of approximately $0.5 billion and have spent approximately $1.1 billion primarily on our pipeline and exploration and production capital programs. Our remaining 2011 capital expenditures are approximately $2.1 billion and remaining debt maturities are approximately $0.5 billion, which we will repay as they mature. Among other financing activities, during the first quarter our MLP also issued approximately $0.5 billion in common units. 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.

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Segment Results

As of March 31, 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 ended March 31:

	2011	2010
	(In millions)	
Segment		
Pipelines	$ 499	$ 452
Exploration and Production	(31)	390
Marketing	(14)	17
Other	(59)	(11)
Segment EBIT	395	848
Interest and debt expense	(240)	(243)
Income tax expense	(19)	(186)
Net income	136	419
Net income attributable to noncontrolling interests	(74)	(31)
Net income attributable to El Paso Corporation	$ 62	$ 388

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Pipelines Segment

Overview and Operating Results. Our Pipelines Segment EBIT for the quarter ended March 31, 2011 increased 10 percent from the first quarter of 2010 benefiting primarily from several expansion projects placed in service in 2010 and an increase in AFUDC related to pipeline expansion projects not yet in service, including our Ruby project, offset by a decline in reservation revenues from our EPNG system due to lower demand and firm transportation commitments. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting Segment EBIT for the quarters ended March 31, 2011 compared with 2010, or that could potentially impact Segment EBIT in future periods.

	2011	2010
	(In millions, except for volumes)	
Operating revenues	$ 753	$ 737
Operating expenses	(378)	(356)
Operating income	375	381
Other income, net	124	71
Segment EBIT	$ 499	$ 452
Throughput volumes (BBtu/d)[(1)(2)]	18,062	18,811

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

(2) March 31, 2010 amount includes throughput volumes of 748 BBtu/d related to our Mexican pipeline assets which were sold in 2010.

	Variance			
	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)			
Expansions	$ 41	$ (9)	$ 49	$ 81
Reservation and usage revenues	(26)	(3)		(29)
Gas not used in operations and revaluations	7	(1)		6
Operating and general and administrative expense		(12)		(12)
Asset write downs		10		10
Other[(1)]	(6)	(7)	4	(9)
Total impact on Segment EBIT	$ 16	$ (22)	$ 53	$ 47

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

Expansions. During 2011, we benefited from increased reservation revenues due to placing the WIC System expansion, Phase A of both the SLNG Elba Expansion III and Elba Express Pipeline expansion, the CIG Raton 2010 expansion, and Phase I of the SNG South System III expansion in service. In April 2011, the FGT Phase VIII Expansion was placed in service on time and on budget. We own a 50 percent interest in Citrus, which owns the FGT system.

Additionally, in the first quarter of 2011, we began construction on the TGP 300 Line pipeline and the remaining compressor facilities. We expect the project to be placed in service in November 2011.

We capitalize a carrying cost (AFUDC) on funds related to our construction of long-lived assets. During the quarter ended March 31, 2011, we benefited from an increase in other income of approximately $49 million associated with the equity portion of AFUDC on our expansion projects. This increase was 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. Additionally, Ruby proposed in its filing to limit total AFUDC accruals to the total amounts included in the original certificate order. The FERC has not yet issued an order on the proposed amendment of the certificate.

Until placed in service, our Ruby project will be consolidated in our financial results. We currently fund and reflect 100 percent of the capital cost of this project, including cost overruns, in our results which reflect higher AFUDC capitalized due to project delays. Shortly after completion of this project, subject to meeting certain conditions, we anticipate reflecting Ruby in our financial statements as an equity investment in which we own 50 percent. Once deconsolidated, we will be required to evaluate our investment in Ruby for impairment. Based on increased costs and delays in project completion which impact the net book value of our investment, depending on the fair value at the time of evaluation, we may be required to write-down a portion of our investment in Ruby. Additionally, we will reflect equity earnings from Ruby in Segment EBIT after the impact of interest expense and preferred interests. As such, our Segment EBIT contribution from Ruby will decline once the pipeline is placed in service. Our level of earnings will depend on the level of contracted customer capacity and our ability to market unsubscribed firm capacity. Currently, approximately 1.1 Bcf/d of the total design capacity of 1.5 Bcf/d on our Ruby pipeline project is subscribed. In the near term, based on current market conditions, we do not expect additional long-term firm capacity subscriptions.

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Reservation and Usage Revenues. During the quarter ended March 31, 2011, our reservation and usage revenues decreased primarily on our EPNG system due to the nonrenewal of expiring contracts as a result of reduced basis differentials and lower throughput volumes as a result of storage withdrawals in California and increased competition in its California and Arizona market areas. The impact of these items unfavorably impacted our Segment EBIT by $21 million when compared with the prior period.

Gas Not Used in Operations and Revaluations. During the quarter ended March 31, 2011, our Segment EBIT, primarily on our TGP system, was favorably impacted by $16 million due to higher volumes and realized prices on operational and other gas sales, partially offset by lower retained fuel volumes in excess of fuel used in operations and lower prices of approximately $11 million, as compared with the same period in 2010. Our future earnings may be impacted positively or negatively depending on changes in throughput and fluctuations in natural gas prices. We continue to explore options to minimize the price volatility associated with these operational pipeline activities. As a result of the TGP rate case filed with the FERC which proposes a change in its rate structure. The percentage of our revenues on TGP derived from reservation charges may increase relative to revenues derived from excess fuel recoveries.

Operating and General and Administrative Expenses. During the quarter ended March 31, 2011, our operating and general and administrative expenses were higher compared to the same period in 2010 primarily due to higher benefits, payroll, and contractor costs.

Asset Write Downs. 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.

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 in 2011 as further described in Item 1, Financial Statements, Note 7 and below.

EPNG Rate Case. In September 2010, EPNG filed a new rate case proposing an increase in its base tariff rates which would increase revenue by approximately $100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not determinable.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates which would increase reservation revenues by approximately $200 million annually over previously effective tariff rates. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not determinable.

CIG Rate Case. In February 2011, the FERC approved an amendment of CIG s 2006 rate case settlement allowing the effective date of a required new rate case to be moved to December 1, 2011. In April 2011, CIG filed a second petition to amend the effective date of a required new rate case to be moved to February 1, 2012 to allow CIG and its shippers the opportunity to reach a settlement of the rate proceeding before it is formally filed with the FERC. The FERC has not ruled on that petition. At this time, the outcome of the pre-filing settlement negotiations and the outcome of the upcoming general rate case, in the event pre-filing settlement cannot be reached, are uncertain.

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

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. In March 2011, we also announced that we would develop our Eagle Ford program without a partner.

Significant Operational Factors Affecting the Quarter Ended March 31, 2011

Production. Our average daily production for the three months ended March 31, 2011 was 821 MMcfe/d, including 63 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the quarters ended March 31:

	2011	**2010**
	MMcfe/d	
United States		
Central	406	331
Western	155	151
Southern	166	214
International		
Brazil	31	21
Total Consolidated	758	717
Four Star	63	64
Total Combined	821	781

Central division Our 2011 Central division production volumes continued to increase as a result of our successful drilling programs in the Haynesville shale. At March 31, 2011, we had 74 operated wells and our total production was approximately 258 MMcfe/d.

Western division Our 2011 Western division production volumes increased primarily due to our successful drilling programs in Altamont offset by natural declines in the Rockies.

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 10 additional wells, for a total of 31 wells. These wells are located principally in the liquids rich area. We also continue to assess our

Wolfcamp shale area.

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Brazil Our 2011 production in Brazil increased due to production from our Camarupim Field. We continue to work with Petrobras in this field where a fourth well is expected to begin production in late second quarter of 2011. We also continue the process of obtaining regulatory and environmental approvals in the Pinauna Field in the Camamu Basin that are required in order to enter the next phase of development.

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. During the quarter ended March 31, 2011, cash operating costs per unit decreased to $1.85/Mcfe as compared to $1.88/Mcfe during the same period in 2010, due to higher production volumes.

Capital Expenditures. Our total oil and natural gas capital expenditures were $352 million for the quarter ended March 31, 2011, of which $348 million were domestic capital expenditures.

Outlook for 2011. Our guidance related to capital expenditures, production volumes, cash operating costs, and depreciation, depletion and amortization is consistent with those outlined in our 2010 Annual Report on Form 10-K. We continue to review our capital program in light of changes in commodity prices, our decision not to seek a partner for our Eagle Ford shale acreage, the results of our core programs, and potential acquisitions and divestitures.

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 the entirety of our price risks, this strategy only partially reduces our commodity price exposure. Our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company. During the first quarter of 2011, approximately 80 percent of our natural gas production and 100 percent of our crude oil production were economically hedged at average floor prices of $5.81 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 March 31, 2011.

	2011		2012		2013	
	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]
Natural Gas						
Fixed Price Swaps	134	$ 5.76	105	$ 6.01		$
Ceilings	14	$ 7.29		$		$
Floors	14	$ 6.00		$		$
Basis Swaps [(2)]						
Texas Gulf Coast	25	$ (0.13)		$		$
Raton	16	$ (0.25)		$		$
Oil						
Fixed Price Swaps	1,513	$87.54	640	$100.13		$
Ceilings		$	1,464	$ 95.00	2,920	$96.88
Three Way Collars Ceiling	2,750	$94.27	4,300	$108.69		$
Three Way Collars Floors [(3)]	2,750	$85.14	4,300	$ 90.00		$

(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) Assumes market prices are at or above $65.00. If prices drop below $65.00, our three way collars-floors effectively lock-in a cash settlement of $20.14 above market prices for 2011 and a cash settlement of $25.00 above market prices for 2012.

Operating Results and Variance Analysis

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

	Quarter Ended March 31, 2011	Quarter Ended March 31, 2010
	(In millions)	
Physical sales		
Natural gas	$ 240	$ 288
Oil and condensate	103	75
NGL	15	18
Total physical sales	358	381
Realized and unrealized (losses) gains on financial derivatives	(109)	253
Other revenues	1	13
Total operating revenues	250	647
Operating expenses		
Cost of products		10

Transportation costs	20	18
Production costs	73	69
Depreciation, depletion and amortization	134	107
General and administrative expenses	50	49
Ceiling test charges		2
Other	3	4
Total operating expenses	280	259
Operating (loss) income	(30)	388
Other (expense) income [1]	(1)	2
Segment EBIT	$ (31)	$ 390

(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 inclusive of the impacts of financial derivative settlements. Our average realized prices, including financial derivative settlements, reflect cash received and/or paid during the period on settled financial derivatives based on the period the contracted settlements were originally scheduled to occur; however, these prices do not reflect the impact of any associated premiums paid to enter into certain of our derivative contracts.

	Quarter Ended March 31,	
	2011	2010
Volumes		
Natural gas (MMcf)		
Consolidated volumes	59,262	56,147
Unconsolidated affiliate volumes	4,253	4,214
Oil and condensate (MBbls)		
Consolidated volumes	1,194	999
Unconsolidated affiliate volumes	82	90
NGL (MBbls)		
Consolidated volumes	293	403
Unconsolidated affiliate volumes	152	156
Equivalent volumes		
Consolidated MMcfe	68,187	64,557
Unconsolidated affiliate MMcfe	5,660	5,690
Total combined MMcfe	73,847	70,247
Consolidated MMcfe/d	758	717
Unconsolidated affiliate MMcfe/d	63	64
Total combined MMcfe/d	821	781
Consolidated prices and costs per unit		
Natural gas ($/Mcf)		
Average realized price on physical sales	$ 4.06	$ 5.13
Average realized price, including financial derivative settlements(1)(2)	$ 5.44	$ 6.04
Average transportation costs	$ 0.31	$ 0.29
Oil and condensate ($/Bbl)		
Average realized price on physical sales	$ 86.27	$ 75.00
Average realized price, including financial derivative settlements(1)(2)	$ 85.69	$ 73.26
Average transportation costs	$ 0.06	$ 0.05
NGL ($/Bbl)		
Average realized price on physical sales	$ 50.37	$ 44.67
Average transportation costs	$ 5.01	$ 2.79
Production costs and other cash operating costs ($/Mcfe)		
Average lease operating expenses	$ 0.74	$ 0.75
Average production taxes(3)	0.32	0.31
Total production costs	$ 1.06	$ 1.06
Average general and administrative expenses	0.74	0.76
Average taxes, other than production and income taxes	0.05	0.06

Total cash operating costs	$	1.85	$	1.88
Depreciation, depletion and amortization ($/Mcfe)(4)	$	1.96	$	1.67

(1) We had no cash premiums related to natural gas and oil derivatives settled during the quarter ended March 31, 2011. Premiums related to natural gas derivatives settled during the quarter ended March 31, 2010 were $52 million. Had we included these premiums in our natural gas average realized prices in 2010, our realized price, including financial derivative settlements, would have decreased by $0.93/Mcf for the quarter ended March 31, 2010. We had no cash premiums related to oil derivatives settled during the quarter ended March 31, 2010.

(2) The quarters ended March 31, 2011 and 2010 include approximately $82 million and $51 million, respectively, of cash receipts on settlements related to natural gas derivative contracts and approximately $1 million for each quarter, respectively, of cash paid on settlements related to crude oil derivative contracts.

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

(4) Includes $0.06 per Mcfe and $0.07 per Mcfe for the quarters ended March 31, 2011 and 2010 related to accretion expense on asset retirement obligations.

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Quarter Ended March 31, 2011 Compared with Quarter Ended March 31, 2010

Our Segment EBIT for the quarter ended March 31, 2011 decreased $421 million as compared to the same period in 2010. The table below shows the significant variances of our financial results for the quarter ended March 31, 2011 as compared with the same period in 2010:

	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Lower realized prices in 2011	$ (64)	$	$	$ (64)
Higher volumes in 2011	16			16
Oil and condensate				
Higher realized prices in 2011	13			13
Higher volumes in 2011	15			15
NGL				
Higher realized prices in 2011	2			2
Lower volumes in 2011	(5)			(5)
Realized and unrealized gains (losses) on financial derivatives	(362)			(362)
Other revenues	(12)			(12)
Depreciation, depletion and amortization expense				
Higher depletion rate in 2011		(21)		(21)
Higher production volumes in 2011		(6)		(6)
Production costs				
Higher lease operating expenses in 2011		(2)		(2)
Higher production taxes in 2011		(2)		(2)
General and administrative expenses		(1)		(1)
Ceiling test charges		2		2
Earnings from investment in Four Star			(2)	(2)
Other		9	(1)	8
Total Variances	$ (397)	$ (21)	$ (3)	$ (421)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the first quarter of 2011 our revenues from physical sales decreased compared to the same quarter of 2010. Natural gas prices continued to decline, although focus on our core programs in the Haynesville and Eagle Ford shale increased oil and natural gas production volumes in the first quarter of 2011.

Realized and unrealized gains (losses) on financial derivatives. During the first quarter of 2011, we recognized net losses of $109 million compared to net gains of $253 million during the same period 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 first quarter of 2011, our depreciation, depletion and amortization expense increased as a result of a higher depletion rate and higher production volumes compared with the same quarter in 2010. In 2009, we recorded ceiling test charges which significantly lowered our depletion rate. We expect the upward trend in our depletion rate relative to prior periods to continue as we focus our capital on developing our core programs.

General and administrative expenses. During the first quarter of 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 lower labor-related costs. The impact of these severance costs was approximately $5 million, or $0.07 per Mcfe on total cash operating costs.

Production costs. Our production costs increased during the first quarter of 2011 as compared to the same period in 2010 primarily due to higher lease operating expenses and higher production taxes as a result of higher production volumes. Production costs per unit were relatively flat when comparing these periods.

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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.

Other. Our equity earnings from Four Star decreased by $2 million during the first quarter of 2011 as compared to the same period in 2010 primarily due to the impact of lower natural gas prices. Four Star s results are more sensitive to changes in natural gas prices as production volumes are predominantly natural gas.

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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 March 31, 2011, these contracts require us to pay demand charges of $31 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 March 31, 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 ended March 31 are as follows:

	2011	2010
	(In millions)	
Income (Loss):		
Contracts Related to Legacy Trading Operations:		
Changes in fair value of power contracts	$ (1)	$ 18
Natural gas transportation-related contracts:		
Demand charges	(10)	(9)
Settlements, net of termination payments	(1)	11
Changes in fair value of other natural gas derivative contracts		(1)
Total revenues	(12)	19
Operating expenses	(2)	(2)
Operating income (loss)	$ (14)	$ 17
Other income, net		
Segment EBIT	$ (14)	$ 17

Our first quarter 2011 results were primarily driven by a $15 million loss related to settlements on an affiliated fuel supply agreement. Our first quarter 2010 results were primarily driven by an $18 million mark-to-market gain on our legacy power contracts due to changes in the locational power prices used to value the contracts.

Other Activities

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

Midstream. As of March 31, 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 gathering and processing system and 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 Marcellus shale in Pennsylvania, the Eagle Ford area, and opportunities in emerging shale plays in the Rockies, west Texas and the northeast United States. 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 ended March 31:

Income (Loss)	**2011**	**2010**
	(In millions)	
Loss on debt extinguishment	$ (41)	$
Change in environmental, legal, and other reserves	(11)	(8)
Midstream	2	
Other	(9)	(3)
Total Segment EBIT	$ (59)	$ (11)

Loss on Debt Extinguishment. During the first quarter of 2011, we recorded a total loss of $41 million in conjunction with repurchasing $148 million of our notes due in 2012 through 2025 for cash. In April 2011, we repurchased an additional $153 million of our notes which will result in recording a loss of approximately $19 million in the second quarter of 2011. We will continue to evaluate repurchasing debt as conditions warrant for the remainder of 2011 which may result in additional losses.

Environmental, Legal and Other Reserves. We have a number of pending litigation and environmental 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 may continue to impact our future results.

Interest and Debt Expense

Our interest and debt expense decreased during the quarter ended March 31, 2011 as compared to the same period in 2010 primarily due to the exchange or repurchase of debt as described below. This decrease was offset by the 2010 issuance of approximately $1.3 billion of EPPOC notes having rates ranging from 4.1 percent to 7.5 percent and increases in Ruby pipeline project financing, net of higher capitalized AFUDC related to debt, primarily associated with the Ruby pipeline project.

In 2010 and 2011, we exchanged or repurchased approximately $1.2 billion of debt having rates ranging from 7 percent to 12 percent as further described in our 2010 Annual Report on Form 10-K and in Note 6. Interest savings associated with these liability management transactions have been offset by interest costs on new borrowings.

Income Taxes

	Quarter Ended March 31,	
	2011	**2010**
	(In millions, except for rates)	
Income taxes	$ 19	$ 186

Effective tax rate	12%	31%

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 3.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Note 7, 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 Update and Liquidity Outlook for 2011. As of March 31, 2011, we had approximately $2.8 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby). The increase in our available liquidity during the first quarter of 2011 was primarily the result of issuing additional MLP common units in conjunction with contributing additional ownership interests in SNG to our MLP. During the first quarter of 2011, among other activities, we continued to repurchase notes and also borrowed the remaining amount under our seven-year amortizing $1.5 billion Ruby financing facility to support the construction of the Ruby pipeline project.

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 quarter ended March 31, 2011, and the amount of cash we expect to spend for the remainder of 2011 to grow and maintain our businesses are as follows:

	Quarter Ended March 31, 2011	2011 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.1	$ 0.3	$ 0.4
Growth[(1)]	0.7	0.6	1.3
Exploration and Production	0.3	1.0	1.3
Other[(2)]		0.2	0.2
	$ 1.1	$ 2.1	$ 3.2

(1) Our pipeline growth capital expenditures reflect 100 percent of capital related to our Ruby project. We have a partner on this project as described below.

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

GIP, our 50 percent partner in the Ruby pipeline project, has provided approximately $700 million to support the Ruby 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. We have also provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, as of March 31, 2011, we have $350 million outstanding in letters of credit to cover anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender s engineer in subsequent months, additional collateral may be required to be issued pursuant to the Ruby financing agreements. For a further description of this project and our agreement with GIP, see our 2010 Annual Report on Form 10-K and Note 11.

We expect our current liquidity sources and operating cash flow to be sufficient to fund our estimated 2011 capital program. For the remainder of 2011, we also have remaining debt maturities of approximately $500 million 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, 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 fund our long-term capital needs if the financial markets are restricted, or a further decline in commodity prices. If these events occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program, reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects or 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 quarter of 2011, we generated operating cash flow of approximately $0.5 billion primarily from our pipeline and exploration and production operations. We also generated approximately $1.3 billion in the first quarter as a result of Ruby and other consolidated project financings, as well as the issuance of MLP common units. We used cash flow generated from these operating and financing activities to fund our capital programs and to make net repayments under our various credit facilities and other

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debt obligations, among other items. For the quarter ended March 31, 2011, our cash flows are summarized as follows:

		2011 (In billions)
Cash Flow from Operations		
Operating activities		
Net income	$	0.1
Other income adjustments		0.2
Change in assets and liabilities		0.2
Total cash flow from operations	$	0.5
Other Cash Inflows		
Financing activities		
Net proceeds from the issuance of long-term debt		0.8
Net proceeds from the issuance of noncontrolling interests		0.5
Total other cash inflows	$	1.3
Cash Outflows		
Investing activities		
Capital expenditures	$	1.1
Financing activities		
Payments to retire long-term debt and other financing obligations		0.8
Total cash outflows	$	1.9
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 derivatives to changes in fair values arising from immediate selected potential changes in the market prices (primarily natural gas, oil and power prices and basis differentials) used to value these contracts. This table reflects the sensitivities of the derivative contracts only and does not include any impacts on the underlying hedged commodities.

		Change in Market Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(In millions)				
Production-related derivatives net assets (liabilities)					
March 31, 2011	$ 50	$(187)	$(237)	$ 274	$224
December 31, 2010	$ 237	$ 33	$(204)	$ 434	$197
Other commodity-based derivatives net assets (liabilities)					
March 31, 2011	$(394)	$(393)	$ 1	$(394)	$
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 March 31, 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 March 31, 2011.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the first 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 7, 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. There have been no material changes in our risk factors since that report.

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

None.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	EL PASO CORPORATION
Date: May 6, 2011	/s/ John R. Sult
	John R. Sult Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: May 6, 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
*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.