EL PASO CORP/DE
Form 10-Q
November 06, 2007

Table of Contents

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

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2007

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer 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 November 2, 2007: 700,486,166

EL PASO CORPORATION
TABLE OF CONTENTS

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

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

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

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

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended September 30, 2007	Quarters Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Operating revenues	$ 1,166	$ 942	$ 3,386	$ 3,368
Operating expenses				
Cost of products and services	55	69	170	201
Operation and maintenance	348	334	978	957
Depreciation, depletion and amortization	293	260	850	766
Taxes, other than income taxes	53	61	185	180
	749	724	2,183	2,104
Operating income	417	218	1,203	1,264
Earnings (losses) from unconsolidated affiliates	(6)	55	75	121
Loss on debt extinguishment		(17)	(287)	(26)
Other income, net	72	51	178	142
Interest and debt expense	(228)	(294)	(742)	(941)
Income before income taxes from continuing operations	255	13	427	560
Income taxes	100	(98)	151	14
Income from continuing operations	155	111	276	546
Discontinued operations, net of income taxes		24	674	95
Net income	155	135	950	641
Preferred stock dividends	9	9	28	28
Net income available to common stockholders	$ 146	$ 126	$ 922	$ 613
Basic earnings per common share				
Income from continuing operations	$ 0.21	$ 0.15	$ 0.36	$ 0.77
Discontinued operations, net of income taxes		0.03	0.97	0.14
Net income per common share	$ 0.21	$ 0.18	$ 1.33	$ 0.91
Diluted earnings per common share				
Income from continuing operations	$ 0.20	$ 0.15	$ 0.35	$ 0.74
Discontinued operations, net of income taxes		0.03	0.96	0.13
Net income per common share	$ 0.20	$ 0.18	$ 1.31	$ 0.87

Dividends declared per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.12

See accompanying notes.

Table of Contents

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

	September 30, 2007	December 31, 2006
ASSETS		
Current assets		
Cash and cash equivalents	$ 389	$ 537
Accounts and notes receivable		
Customers, net of allowance of $18 in 2007 and $28 in 2006	445	516
Affiliates	195	192
Other	210	495
Assets from price risk management activities	166	436
Assets held for sale and from discontinued operations		4,161
Deferred income taxes	358	478
Other	266	352
Total current assets	2,029	7,167
Property, plant and equipment, at cost		
Pipelines	16,407	15,672
Natural gas and oil properties, at full cost	18,673	16,572
Other	537	566
	35,617	32,810
Less accumulated depreciation, depletion and amortization	16,698	16,132
Total property, plant and equipment, net	18,919	16,678
Other assets		
Investments in unconsolidated affiliates	1,638	1,707
Assets from price risk management activities	238	414
Other	1,257	1,295
	3,133	3,416
Total assets	$ 24,081	$ 27,261

See accompanying notes.

Table of Contents

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

	September 30, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 381	$ 478
Affiliates	1	3
Other	498	569
Current maturities of long-term financing obligations	567	1,360
Liabilities from price risk management activities	276	278
Liabilities related to discontinued operations		1,817
Accrued interest	250	269
Other	804	1,377
Total current liabilities	2,777	6,151
Long-term financing obligations, less current maturities	12,445	13,329
Other		
Liabilities from price risk management activities	884	924
Deferred income taxes	1,204	950
Other	1,743	1,690
	3,831	3,564
Commitments and contingencies (Note 7)		
Securities of subsidiaries	22	31
Stockholders equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares of 4.99% convertible perpetual stock; stated at liquidation value	750	750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 709,015,253 shares in 2007 and 705,833,206 shares in 2006	2,127	2,118
Additional paid-in capital	4,724	4,804
Accumulated deficit	(1,994)	(2,940)
Accumulated other comprehensive loss	(413)	(343)
Treasury stock (at cost); 8,475,883 shares in 2007 and 8,715,288 shares in 2006	(188)	(203)
Total stockholders equity	5,006	4,186
Total liabilities and stockholders equity	$ 24,081	$ 27,261

See accompanying notes.

Table of Contents

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

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Cash flows from operating activities		
Net income	$ 950	$ 641
Less income from discontinued operations, net of income taxes	674	95
Income from continuing operations	276	546
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	850	766
Deferred income taxes	127	(15)
Earnings from unconsolidated affiliates, adjusted for cash distributions	81	16
Loss on debt extinguishment	287	26
Other	(52)	53
Asset and liability changes	(76)	340
Cash provided by continuing activities	1,493	1,732
Cash provided by (used in) discontinued activities	(31)	280
Net cash provided by operating activities	1,462	2,012
Cash flows from investing activities		
Capital expenditures	(1,796)	(1,510)
Cash paid for acquisitions, net of cash acquired	(1,182)	
Net proceeds from the sale of assets and investments	82	501
Net change in restricted cash	33	101
Other	17	24
Cash used in continuing activities	(2,846)	(884)
Cash provided by discontinued activities	3,660	229
Net cash provided by (used) in investing activities	814	(655)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	5,253	125
Payments to retire long-term debt and other financing obligations	(7,286)	(2,990)
Dividends paid	(112)	(108)
Net proceeds from issuance of common stock		500
Contributions from discontinued operations	3,346	277
Other	4	(25)
Cash provided by (used in) continuing activities	1,205	(2,221)
Cash used in discontinued activities	(3,629)	(509)

Net cash used in financing activities	(2,424)	(2,730)
Change in cash and cash equivalents	(148)	(1,373)
Cash and cash equivalents		
Beginning of period	537	2,132
End of period	$ 389	$ 759

See accompanying notes.

Table of Contents

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 155	$ 135	$ 950	$ 641
Foreign currency translation adjustments (net of income taxes of less than $1 in 2006)		3		5
Net reclassification adjustments (net of income taxes of $3 and $10 in 2007) associated with pension and other postretirement obligations	5		18	
Cash flow hedging activities:				
Unrealized mark-to-market gains arising during period (net of income taxes of $22 and $3 in 2007 and $51 and $174 in 2006)	39	92	6	311
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $22 and $46 in 2007 and $3 and $18 in 2006)	(38)	4	(78)	29
Investments available for sale:				
Unrealized gains (losses) arising during period (net of income taxes $2 in 2007 and $1 and $4 in 2006)		(2)	3	7
Realized gains arising during period (net of income taxes of $8 in 2007)			(15)	
Other comprehensive income (loss)	6	97	(66)	352
Comprehensive income	$ 161	$ 232	$ 884	$ 993

See accompanying notes.

Table of Contents

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles. You should read this Quarterly Report on Form 10-Q along with our 2006 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2007, and for the quarters and nine months ended September 30, 2007 and 2006, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2006, from the audited balance sheet filed in our 2006 Annual Report on Form 10-K. In our opinion, we have made all adjustments, which are of a normal recurring nature, to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year. Our results for all periods reflect ANR Pipeline Company (ANR), our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission (Great Lakes) as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or stockholders equity.

Significant Accounting Policies

The information below provides an update to the significant accounting policies and accounting pronouncements issued but not yet adopted discussed in our 2006 Annual Report on Form 10-K.

Accounting for Uncertainty in Income Taxes. On January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes* and its related interpretation. FIN No. 48 clarifies Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes,* and requires us to evaluate our tax positions for all jurisdictions and for all years where a statute of limitations has not expired. FIN No. 48 requires companies to meet a more-likely-than-not threshold (i.e., a greater than 50 percent likelihood that a tax position would be sustained under examination) prior to recording a benefit for their tax positions. Additionally, for tax positions meeting this more-likely-than-not threshold, the amount of benefit is limited to the largest benefit that has a greater than 50 percent probability of being realized upon effective settlement. For information on the impact on our financial statements of the adoption of this interpretation, see Note 3.

Accounting for Offsetting Contractual Amounts. In April 2007, the FASB issued FASB Staff Position (FSP) No. FIN 39-1. The FSP amends FIN No. 39, *Offsetting of Amounts Related to Certain Contracts*, and allows companies to offset amounts recorded for their derivative contracts with cash collateral posted or held if the contracts are executed with the same counterparty and under the same master netting arrangement. This pronouncement is effective for fiscal years beginning after November 15, 2007, although early application is permitted. We are currently evaluating the manner in which we will apply this pronouncement.

2. Acquisitions and Divestitures

Acquisitions

On September 28, 2007, we acquired Peoples Energy Production Company (Peoples) for $879 million in cash using cash on hand and borrowings under our revolving credit facilities. Peoples is an exploration and production company with natural gas and oil properties located primarily in the ArkLaTex, Texas Gulf Coast and Mississippi areas and in the San Juan and Arkoma Basins. We accounted for this acquisition under the purchase method of accounting and preliminarily allocated the purchase price to natural gas and oil properties on our balance sheet. This allocation is subject to change. We did not record any goodwill associated with this transaction.

Table of Contents

In January 2007, we acquired producing properties and undeveloped acreage in Zapata County, Texas for $254 million. Also, in the third quarter of 2007, we increased our ownership interest in Four Star, our unconsolidated affiliate, from 43 percent to 49 percent.

Divestitures

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals to be disposed of by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these discontinued operations do not maintain separate cash balances, we reflect the net cash flows generated from these businesses as a contribution to our continuing operations in cash flows from continuing financing activities. As of December 31, 2006, we had total assets of $4.1 billion and total liabilities of $1.8 billion related to our discontinued operations, the composition of which is disclosed in our 2006 Annual Report on Form 10-K. We also had $28 million of assets held for sale as of December 31, 2006. As of September 30, 2007, all of our assets and liabilities related to our discontinued operations and our assets held for sale had been sold.

Discontinued Operations. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes to TransCanada Corporation and TC Pipeline, LP for net cash proceeds of approximately $3.7 billion and recorded a gain on the sale of $648 million, net of taxes of $354 million. Included in the net assets of these discontinued operations as of the date of the sale were net deferred tax liabilities assumed by TransCanada. During 2006, we completed the sale of all of our discontinued international power operations for net proceeds of approximately $368 million including our interest in Macae, a wholly owned power plant facility in Brazil, and certain power assets in Asia and Central America.

Below is summarized income statement information regarding our discontinued operations:

	ANR and Related Operations	Other	Total
		(In millions)	
Nine Months Ended September 30, 2007			
Revenues	$ 101	$	$ 101
Costs and expenses	(43)		(43)
Other expense[(1)]	(7)		(7)
Interest and debt expense	(10)		(10)
Income taxes	(15)		(15)
Income from operations	26		26
Gain on sale, net of income taxes of $354 million	648		648
Net income from discontinued operations	$ 674	$	$ 674
Quarter Ended September 30, 2006			
Revenues	$ 120	$ 28	$ 148
Costs and expenses	(82)	(33)	(115)
Other income	14	2	16
Interest and debt expense	(16)	(1)	(17)
Income taxes	(12)	4	(8)
Net income from discontinued operations	$ 24	$	$ 24

Nine Months Ended September 30, 2006			
Revenues	$ 439	$ 131	$ 570
Costs and expenses	(251)	(144)	(395)
Other income	45	4	49
Interest and debt expense	(49)	(14)	(63)
Income taxes	(67)	1	(66)
Net income (loss) from discontinued operations	$ 117	$ (22)	$ 95

(1) Includes a loss of approximately $19 million associated with the extinguishment of certain debt obligations.

Continuing operations asset sales. During the nine months ended September 30, 2007, we received approximately $82 million of proceeds from the sales of assets and investments, primarily related to the sale of a pipeline lateral and our investment in the New York Mercantile Exchange (NYMEX). During the nine months ended September 30, 2006 we received approximately $501 million of proceeds, primarily related to the sale of our interests in power plants in Brazil, Asia and Central America and certain natural gas and oil properties in south Texas.

3. Income Taxes

Income taxes included in our income from continuing operations for the periods ended September 30 were as follows:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions, except rates)			
Income taxes	$100	$ (98)	$151	$14
Effective tax rate	39%	(754)%	35%	3%

We compute interim period income taxes by applying an anticipated annual effective tax rate to our year-to-date income or loss, except for significant unusual or infrequently occurring items. Significant tax items, which may include the conclusion of income tax audits, are recorded in the period that the item occurs. Our 2007 overall year-to-date effective tax rate on continuing operations was consistent with the statutory rate. Increases to our effective tax rate due to impairments on foreign investments for which there were no corresponding income tax benefits, along with state income taxes (net of federal income tax effects) and the reversal of deferred tax assets on certain foreign investments were offset by tax benefits associated with recent tax law changes and dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends. Our 2007 quarterly effective tax rate was higher than the statutory rate due primarily to impairments on foreign investments for which there were no corresponding income tax benefits.

During 2006, our overall effective tax rate on continuing operations was lower than the statutory rate of 35 percent primarily due to conclusion of IRS audits of The Coastal Corporation s 1998-2000 tax years and El Paso s 2001 and 2002 tax years which resulted in the reduction of tax contingencies and the reinstatement of certain tax credits. Also, impacting the rate were net tax benefits recognized on certain foreign investments. The total net tax benefit associated with the items above was $105 million and $163 million for the quarter and nine months ended September 30, 2006.

We file income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. With a few exceptions, we are no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 1999. Additionally, the Internal Revenue Service has completed an examination of El Paso s U.S. income tax returns for 2003 and 2004, with a tentative settlement at the appellate level for all issues. While the settlement of these matters is expected to change our unrecognized tax benefits in the next twelve months, we do not anticipate the impact to be material to our results of operations, financial condition or liquidity. For our remaining open tax years, our unrecognized tax benefits (liabilities for uncertain tax matters) could increase or decrease our income tax expense and effective income tax rates as these matters are finalized.

Upon the adoption of FIN No. 48, we recorded additional liabilities for unrecognized tax benefits of $2 million, including interest and penalties, which we accounted for as an increase of $4 million to the January 1, 2007 accumulated deficit and an increase of $2 million to additional paid-in capital. The additional amounts recorded increased our overall unrecognized tax benefits (including interest and penalties) to $178 million as of January 1, 2007. During the third quarter, we increased our gross liability by $25 million related to various tax positions. As a result, our overall unrecognized tax benefits are $207 million as of September 30, 2007. Of these amounts, approximately $109 million as of January 1, 2007 and $136 million as of September 30, 2007 (net of federal tax benefits) would favorably affect our income tax expense and our effective income tax rate if recognized in future periods. While the amount of our unrecognized tax benefits could change in the next twelve months, we do not expect this change to have a significant impact on our results of operations or financial position.

We recognize interest and penalties related to unrecognized tax benefits in income tax expense on our income statement. Total interest and penalties recognized in our income statement was not material for the quarters and nine months ended September 30, 2007 and 2006. As of January 1, 2007, we had approximately $39 million of liabilities for interest and penalties related to our unrecognized tax benefits, which have not materially changed as of September 30, 2007.

Table of Contents

4. Earnings Per Share

We calculated basic and diluted earnings per common share as follows:

	2007		2006	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Quarter Ended September 30,				
Income from continuing operations	$ 155	$ 155	$ 111	$ 111
Convertible preferred stock dividends	(9)		(9)	(9)
Income from continuing operations available to common stockholders	146	155	102	102
Discontinued operations, net of income taxes			24	24
Net income available to common stockholders	$ 146	$ 155	$ 126	$ 126
Weighted average common shares outstanding	696	696	693	693
Effect of dilutive securities:				
Options and restricted stock		5		4
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	696	759	693	697
Earnings per common share:				
Income from continuing operations	$ 0.21	$ 0.20	$ 0.15	$ 0.15
Discontinued operations, net of income taxes			0.03	0.03
Net income	$ 0.21	$ 0.20	$ 0.18	$ 0.18

	2007		2006	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Nine Months Ended September 30,				
Income from continuing operations	$ 276	$ 276	$ 546	$ 546
Convertible preferred stock dividends	(28)	(28)	(28)	
Income from continuing operations available to common stockholders	248	248	518	546
Discontinued operations, net of income taxes	674	674	95	95
Net income available to common stockholders	$ 922	$ 922	$ 613	$ 641
Weighted average common shares outstanding	695	695	673	673
Effect of dilutive securities:				
Options and restricted stock		4		4
Convertible preferred stock				57

Weighted average common shares outstanding and dilutive securities	695	699	673	734
Earnings per common share:				
Income from continuing operations	$ 0.36	$ 0.35	$ 0.77	$ 0.74
Discontinued operations, net of income taxes	0.97	0.96	0.14	0.13
Net income	$ 1.33	$ 1.31	$ 0.91	$ 0.87

We exclude potentially dilutive securities (such as employee stock options, restricted stock, convertible preferred stock, and trust preferred securities) from the determination of diluted earnings per share when their impact on income from continuing operations per common share is antidilutive. These antidilutive securities included certain employee stock options and our trust preferred securities in all periods presented, and our convertible preferred stock for the nine months ended September 30, 2007 and quarter ended September 30, 2006. Additionally, our zero coupon convertible debentures (redeemed in April 2006), were antidilutive in both periods in 2006. For a further discussion of our potentially dilutive securities, see our 2006 Annual Report on Form 10-K.

5. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities. In the table below, derivatives designated as accounting hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts not designated as accounting hedges, such as options, swaps, other natural gas and power purchase and supply contracts, and derivatives related to our legacy energy trading activities. Interest rate and foreign currency derivatives consist of swaps that are primarily designated as hedges of our interest rate and foreign currency risk on long-term debt.

Table of Contents

	September 30, 2007	December 31, 2006
	(In millions)	
Net assets (liabilities):		
Derivatives designated as accounting hedges	$ 23	$ 61
Other commodity-based derivative contracts[1]	(861)	(456)
Total commodity-based derivatives	(838)	(395)
Interest rate and foreign currency derivatives	82	43
Net liabilities from price risk management activities	$ (756)	$ (352)

(1) During 2007, we settled derivative assets of approximately $381 million by applying the related cash margin we held against amounts due to us under those contracts. This non-cash transaction is not reflected in our statement of cash flows.

6. Long-Term Financing Obligations and Other Credit Facilities

	September 30, 2007	December 31, 2006
	(In millions)	
Current maturities of long-term financing obligations	$ 567	$ 1,360
Long-term financing obligations	12,445	13,329
Total	$ 13,012	$ 14,689

Changes in Long-Term Financing Obligations. During the nine months ended September 30, 2007, we had the following changes in our long-term financing obligations (in millions):

Company	Interest Rate	Book Value	Cash Received / (Paid)

			Increase (Decrease)		
Issuances					
El Paso Exploration and Production Company (EPEP)					
Revolving credit facility	variable	$	955	$	952
El Paso					
Revolving credit facility	variable		2,200		2,200
Notes due 2014	6.875%		374		371
Notes due 2017	7.00%		893		886
El Paso Natural Gas (EPNG) notes due 2017	5.95%		354		350
Southern Natural Gas (SNG) notes due 2017	5.90%		500		494
Increases through September 30, 2007		$	5,276	$	5,253
Repayments, repurchases and other					
El Paso	6.375%-10.75%	$	(2,880)	$	(3,054)
El Paso-Euro	7.125%		(157)		(165)
EPEP	7.75%		(1,199)		(1,267)
SNG	6.70%		(52)		(52)
SNG	8.875%		(398)		(418)
EPNG	7.625%		(299)		(314)
Other	various		32		(16)
			(4,953)		(5,286)
Revolving Credit Facilities					
EPEP	variable		(200)		(200)
El Paso	variable		(1,800)		(1,800)
Decreases through September 30, 2007		$	(6,953)	$	(7,286)

During the first nine months of 2007, we recorded $287 million of pre-tax losses on the extinguishment of certain debt obligations repurchased and debt refinanced above. During the quarter and nine months ended September 30, 2006, we recorded $17 million and $26 million of pre-tax losses on the extinguishment of certain debt obligations repurchased and debt refinanced.

Other. Approximately $10 billion of our debt obligations provide us the ability to call the debt prior to its stated maturity date. If redeemed prior to their stated maturities, we will be required to pay a make-whole or fixed premium in addition to repaying the principal and accrued interest.

Prior to their redemption in 2006, we recorded accretion expense on our zero coupon debentures. During the nine months ended September 30, 2006, we redeemed $615 million of our zero coupon debentures, of which $110 million represented an increase in the principal balance of long-term debt due to the accretion of interest on the debentures we redeemed. We account for these redemptions as financing activities in our statement of cash flows.

Credit Facilities/Letters of Credit

Credit Facilities. As of September 30, 2007, we had available capacity under various credit agreements of approximately $0.7 billion. Below is a discussion of changes to our existing credit facilities and our new facilities entered into in 2007. For a further discussion of our credit facilities, see our 2006 Annual Report on Form 10-K.

$1.75 billion credit agreement. As of September 30, 2007, we had approximately $0.6 billion available under our $1.75 billion credit agreement. As a result of upgrades to our credit ratings in March 2007, we can borrow funds utilizing the revolver under this credit agreement at rates of LIBOR plus 1.25% or issue letters of credit at a rate of 1.40%. The commitment fee on any unused capacity under the revolver is 0.25%.

EPEP $1.0 billion revolving credit agreement. In September 2007, we amended and restated EPEP s revolving credit facility, increasing the capacity by $0.5 billion to $1.0 billion. The other material terms and conditions of this facility remain the same. As of September 30, 2007, we had available capacity under this facility of $0.1 billion. Based on current borrowing levels, we pay interest at LIBOR plus 1.50% on borrowings, and a commitment fee of 0.35% on any unused capacity.

Unsecured Credit Facility. In June 2007, we entered into a $150 million unsecured facility that provides for both borrowings and issuing letters of credit. As of September 30, 2007, we increased the size of this facility to $300 million and in October 2007 added an additional $200 million of capacity to this facility, bringing total capacity to $500 million. The facility matures in various tranches during 2009. Based on this facility size, we are required to pay a fixed facility fee at a weighted average rate of 1.64% per annum (1.44% as of September 30, 2007) on the full facility amount. Borrowings carry an interest rate of LIBOR in addition to the facility fee. Substantially all of the capacity was used to issue letters of credit under the facility.

Contingent Letter of Credit Facility. In January 2007, we entered into a $250 million unsecured contingent letter of credit facility that matures in March 2008. Letters of credit are available under the facility if the average NYMEX gas price strip for the remaining calendar months through March 2008 is equal to or exceeds $11.75 per MMBtu, which has not occurred. The facility fee, if triggered, is 1.66% per annum.

Letters of Credit. We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of September 30, 2007, we had outstanding letters of credit of approximately $1.4 billion of which approximately $0.9 billion secures our recorded obligations related to price risk management activities.

7. Commitments and Contingencies

Legal Proceedings

ERISA Class Action Suit. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of Texas alleging that our communication with participants in our Retirement Savings Plan included various misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). Various motions have been filed, and we are awaiting the court s ruling. We have insurance coverage for this lawsuit, subject to certain deductibles and co-pay obligations. We have established accruals for this matter which we believe are adequate.

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 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. Certain of the claims that our cash balance plan violated ERISA were recently dismissed by the trial court. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before July 1, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off in 1994. Tenneco retained an obligation to provide certain medical benefits at the time of the spin-off and we assumed this obligation as a result of our merger with Tenneco. Pursuant to an agreement with the applicable union for Case employees, our liability for these benefits was subject to a cap, such that costs in excess of the cap were to be assumed by plan participants. In 2002, we and Case were sued by individual retirees in a federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation.* The suit alleges, among other things, that El Paso and Case violated ERISA and that they should be required to pay all amounts above the cap. Case further filed claims against El Paso asserting that El Paso was obligated to indemnify Case for the amounts it would be required to pay. In separate rulings in 2004, the court ruled that, pending a trial on the merits, Case must pay the amounts incurred above the cap and that El Paso must reimburse Case for those payments. In January 2006, these rulings were upheld on appeal by the U.S. Court of Appeals for the 6th Circuit. In October 2007, pending a trial on the merits, the court expanded the number of retirees that were covered by its prior preliminary rulings. We will proceed with a trial on the merits with regard to the issues of whether the cap is enforceable and to what degree benefits have actually vested. Until this is resolved, El Paso will indemnify Case for payments Case makes above the cap, which are currently about $2 million per month. We continue to defend the action and have filed for approval by the trial court various amendments to the medical benefit plans which would allow us to deliver the benefits to plan participants in a more cost effective manner. Although it is uncertain what plan amendments will ultimately be approved, the approval of plan amendments could reduce our overall costs and, as a result, could reduce our recorded obligation. We have established an accrual for this matter which we believe is adequate.

Natural Gas Commodities Litigation. Beginning in August 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. The first cases were consolidated in federal court in New York for all pre-trial purposes and are styled *In re: Gas Commodity Litigation.* In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. A settlement was finalized and has been paid. The second set of cases, involving similar allegations on behalf of commercial and residential customers, was transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada and styled *In re: Western States Wholesale Natural Gas Antitrust Litigation*. These cases were dismissed. The U.S. Court of Appeals for the Ninth Circuit, however, reversed the dismissal and ordered that these cases be remanded to the trial court. Defendants have filed a motion for reconsideration of that ruling. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include *Farmland Industries v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in July 2005) and *Missouri Public Service Commission v. El Paso Corporation, et al.* (filed in the circuit court of Jackson County, Missouri at Kansas City in October 2006), and the purported class action lawsuits styled: *Leggett, et al. v. Duke Energy Corporation, et al.* (filed in Chancery Court of Tennessee in January 2005); *Ever-Bloom Inc. v. AEP Energy Services Inc., et al.* (filed in federal court for the Eastern District of California in September 2005); *Learjet, Inc. v. Oneok Inc.,* (filed in state court in Wyandotte County, Kansas in September 2005); *Breckenridge, et al. v. Oneok Inc., et al.* (filed in state court in Denver County, Colorado in May 2006); *Arandell, et al. v. Xcel Energy, et al.* (filed in the circuit court of Dane County, Wisconsin in December 2006); and *Heartland, et al. v. Oneok Inc., et al.* (filed in the circuit court of Buchanan County, Missouri in March 2007). The *Leggett* case was dismissed by the Tennessee state court and has been appealed. The remaining cases have all been transferred to the MDL proceeding. Defendants motions to dismiss in *Farmland, Learjet* and

Breckenridge have been denied. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Gas Measurement Cases. A number of our subsidiaries were named defendants in actions that generally allege mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act, which have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming). These complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands. In October 2006, the U.S. District Judge issued an order dismissing all claims against all defendants. An appeal has been filed.

Similar allegations were filed in a set of actions initiated in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The plaintiffs currently seek certification of a class of royalty owners in wells on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. Motions for class certification have been briefed and argued in the proceedings and the parties are awaiting the court s ruling. The plaintiff seeks an unspecified amount of monetary damages in the form of additional royalty payments (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. Our costs and legal exposure related to these lawsuits and claim are not currently determinable.

MTBE. Certain of our subsidiaries used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of their gasoline. Certain subsidiaries have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding the potential impact of MTBE on water supplies. Some of our subsidiaries are among the defendants in approximately 80 such lawsuits. Although these suits had been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York, a recent appellate court decision directed two of the cases to be remanded back to state court. A limited number of cases have since been remanded to separate state court proceedings. It is possible many of the other cases will also be remanded. The plaintiffs, certain state attorneys general, various water districts and a limited number of individual water customers, generally seek remediation of their groundwater, prevention of future contamination, damages (including natural resource damages), punitive damages, attorney s fees and court costs. Among other allegations, plaintiffs assert that gasoline containing MTBE is a defective product and that defendant refiners are liable in proportion to their market share. While the damages claimed in these actions are substantial, there remains significant legal uncertainty regarding the validity of causes of action asserted and availability of the relief sought by plaintiffs. Although there have been preliminary settlement discussions with the plaintiffs in the past, such discussions have been unsuccessful to date. We have tendered the matter to our insurers and, although the primary layer has agreed to reimburse us for reasonable defense costs, they have reserved their rights to deny coverage for any losses incurred by way of settlement or judgment associated with these proceedings. As a result, our costs and legal exposure related to these lawsuits are not currently determinable.

Government Investigations and Inquiries

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We originally self-reported this matter to the SEC and have been cooperating fully with the investigation, which has included producing a large volume of documents and making our employees available for interviews or testimony upon request. On July 13, 2007, we received a notice indicating the SEC staff has made a preliminary decision to recommend to the SEC that it institute an enforcement action against us and two of our subsidiaries related to the reserve revisions. We understand that the staff of the SEC may have also issued similar notices to several of our former employees related to the reserves revisions. We were given the opportunity to respond to the staff before it makes its formal recommendation on whether any action should be brought by the SEC, and on September 25, 2007 we submitted our response.

Other Government Investigations. We continue to provide information and cooperate with the inquiry or investigation of the U.S. Attorney and the SEC in response to requests for information regarding price reporting of transactional data to the energy trade press.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, we evaluate the merits of the case, 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 September 30, 2007, we had approximately $458 million accrued, net of related insurance receivables, for our outstanding legal and governmental proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In August 2007, EPNG received approval of the settlement of its rate case from the FERC. The settlement provides benefits for both EPNG and its customers for a three year period ending December 31, 2008. Under the terms of the settlement, EPNG is required to file a new rate case to be effective January 1, 2009. EPNG has received approval from the FERC to begin billing the settlement rates on October 1, 2007 and it will refund amounts, with interest, within 120 days of that date. Our financial statements reflect EPNG s proposed rates and we have reserved a sufficient amount to meet the refund obligations under this settlement.

Notice of Inquiry on Pipeline Fuel Retention Policies. In September 2007, the FERC issued a Notice of Inquiry regarding its policy about the in-kind recovery of fuel and lost and unaccounted for gas by natural gas pipeline companies. Under current policy, pipelines have options for recovering these costs. For some pipelines, the tariff states a fixed percentage as a non-negotiable fee-in-kind retained from the volumes tendered for shipment by each shipper. This percentage is changed only through filing a rate case. There is also a tracker approach, where the pipeline s tariff provides for prospective adjustments to the fuel retention rates from time-to-time, but does not include a mechanism to allow the pipeline to reconcile past over or under-recoveries of fuel. Finally, some pipelines tariffs provide for a tracker with a true-up approach, where provisions in a pipeline s tariff allow for periodic adjustments to the fuel retention rates, and also provide for a true-up of past over and under-recoveries of fuel and lost and unaccounted for gas. In this proceeding, the FERC is seeking comments on whether it should change its current policy and prescribe a uniform method for all pipelines to use in recovering these costs. Our pipeline subsidiaries currently utilize a variety of these methodologies and plan to file comments with the FERC. At this time, we do not know what impact this proceeding may ultimately have on any of our pipelines.

Other Contingencies

Iraq Imports. In December 2005, the Ministry of Oil for the State Oil Marketing Organization of Iraq (SOMO) sent an invoice to one of our subsidiaries for shipments of crude oil that SOMO alleged were purchased by Coastal in 1990 just before the 1990 invasion of Kuwait by Iraq. The invoice requests $144 million for such shipments, along with an allegation of an undefined amount of interest. Prior to our merger with Coastal in 2001, Coastal had accrued approximately $77 million for potential claims that SOMO might make for additional payments for these shipments. Following the completion of our review of the invoice and our defenses, including the expiration of the related statute of limitation periods, we determined that no amounts are owed to SOMO, and as a result, we reversed those accrued amounts to other income in our income statement during the third quarter of 2007.

Navajo Nation. Approximately 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on lands held in trust by the United States for the benefit of the Navajo Nation. Our rights-of-way on lands crossing the Navajo Nation are the subject of a pending renewal application filed in 2005 with the Department of the Interior s Bureau of Indian Affairs. An interim agreement with the Navajo Nation expired at the end of December 2006. Negotiations on the terms of the long-term agreement are continuing. In addition, we continue to preserve other legal, regulatory and legislative alternatives, which includes continuing to pursue our application with the Department of the Interior for renewal of our rights-of-way on Navajo Nation lands. It is uncertain whether our negotiation, or other alternatives, will be successful, or if successful, what the ultimate cost will be of obtaining the rights-of-way and whether we will be able to recover these costs in our rates.

Cheyenne Plains (CP) Compression Station Fire. In September 2007, the CP Compressor Station, located near the border between Colorado and Wyoming, experienced a fire which has required CP to temporarily shut down certain of its facilities and reduce service to its customers. We currently expect that full service will be restored in mid-November, and we will be required to provide partial demand charge credits to our shippers during the period in which service levels are reduced. We have business interruption and property insurance and do not anticipate a material impact on our financial results as a result of the shut-down of these facilities.

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 on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2007, we have accrued approximately $275 million, which has not been reduced by $29 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $266 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $9 million for related environmental legal costs.

Table of Contents

Our estimates of potential liability range from approximately $275 million to approximately $486 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($19 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($256 million to $467 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. Our recorded liabilities reflect our current estimates of amounts we will expend to remediate these sites. 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:

	September 30, 2007	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 24	$ 29
Non-operating	223	406
Superfund	28	51
Total	$ 275	$ 486

Below is a reconciliation of our accrued liability from January 1, 2007 to September 30, 2007 (in millions):

Balance as of January 1, 2007	$ 314
Additions/adjustments for remediation activities	19
Payments for remediation activities	(58)
Balance as of September 30, 2007	$ 275

For the remainder of 2007, we estimate that our total remediation expenditures will be approximately $22 million, most of which will be expended under government directed clean-up programs. In addition, we expect to make capital expenditures for environmental matters of approximately $23 million in the aggregate for the remainder of 2007 through 2011. These expenditures primarily relate to compliance with clean air regulations.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 45 active sites under the CERCLA or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements, which provide for payment of our allocable share of remediation costs. As of September 30, 2007, we have estimated our share of the remediation costs at these sites to be between $28 million and $51 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

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 Indemnifications

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support through the issuance of financial and performance guarantees. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of the assets sold.

Table of Contents

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $785 million, for which we are indemnified by third parties for $15 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 6. Included in the above maximum stated value is approximately $440 million related to indemnification arrangements associated with the sale of ANR and related operations and approximately $119 million related to tax matters, related interest and other indemnifications and guarantees arising out of the sale of our Macae power facility. As of September 30, 2007, we have recorded obligations of $38 million related to our guarantees and indemnification arrangements, of which $9 million is related to ANR and related assets and Macae. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments under the agreement due to the uncertainty of these exposures.

In addition to the exposures described above, a trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits being paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $371 million associated with our estimated exposure under this matter as of September 30, 2007. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

8. Retirement Benefits

The components of net benefit cost for our pension and postretirement benefit plans for the periods ended September 30 are as follows:

	Quarters Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006	2007	2006	2007	2006
	(In millions)							
Service cost	$ 4	$ 4	$	$	$ 13	$ 12	$	$
Interest cost	30	29	6	7	90	87	19	21
Expected return on plan assets	(45)	(44)	(4)	(4)	(136)	(132)	(12)	(12)
Amortization of net actuarial loss	11	14			32	42		
Amortization of prior service cost[1]	(1)		1		(2)			
Special termination benefits[2]					6			
Net benefit cost (income)	$ (1)	$ 3	$ 3	$ 3	$ 3	$ 9	$ 7	$ 9

(1) As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period

of employees expected to receive benefits under the plan.

(2) Relates to providing enhanced benefits to former ANR employees, which is included in discontinued operations in our income statement.

In December 2006, we adopted the recognition provisions of SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R)* and began reflecting assets and liabilities related to our pension and other postretirement benefit plans based on their funded or unfunded status and reclassified all actuarial deferrals as a component of accumulated other comprehensive income. In March 2007, the FERC issued guidance requiring regulated pipeline companies to recognize a regulatory asset or liability for the funded status asset or liability that would otherwise be recorded in accumulated other comprehensive income under SFAS No. 158, if it is probable that amounts calculated on the same basis as SFAS No. 106, *Employers Accounting for Postretirement Benefits Other Than Pensions* would be included in rates in future periods. Upon adoption of this FERC guidance, we reclassified approximately $4 million from the beginning balance of accumulated other comprehensive income to other non-current assets and liabilities on our balance sheet.

During the nine months ended September 30, 2007 and 2006, we made $15 million and $54 million of cash contributions to our supplemental benefits plan and other postretirement benefit plans. We also made $2 million of cash contributions to our pension plans for the nine months ended September 30, 2007. For the remainder of 2007, we expect to contribute an additional $6 million to our other postretirement benefit plans, $1 million to our pension plans and less than $1 million to our supplemental benefits plan.

Table of Contents

9. Stockholders Equity

In May 2006, we issued 35.7 million shares of common stock for net proceeds of approximately $500 million. The table below shows the amount of dividends paid and declared in 2007.

	Common Stock ($0.04/Share per Qtr)	Convertible Preferred Stock (4.99%/Year)
	($ in millions)	
Amount paid through September 30, 2007	$84	$ 28
Amount paid in October 2007	$27	$ 9
Declared subsequent to September 30, 2007:		
Date of declaration	October 25, 2007	October 25, 2007
Payable to shareholders on record	December 7, 2007	December 15, 2007
Date payable	January 7, 2008	January 7, 2008

Dividends on our common stock and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For the remainder of 2007, we expect dividends paid on our common and preferred stock will be taxable to our stockholders because we anticipate they will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set aside for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restriction on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If our fixed charge ratio were to exceed the permitted maximum level, our ability to pay additional dividends would be restricted.

10. Business Segment Information

As of September 30, 2007, our business consists of Pipelines, Exploration and Production, Marketing and Power segments. We have reclassified certain operations as discontinued operations for all periods presented (see Notes 1 and 2). 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. Our corporate operations include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets, all of which are immaterial. A further discussion of each segment follows:

Pipelines. Provides natural gas transmission, storage, and related services, primarily in the United States. As of September 30, 2007, we conducted our activities primarily through seven wholly owned and four partially owned transmission systems along with two underground natural gas storage entities and an LNG terminalling facility.

Exploration and Production. Engages in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States, Brazil and Egypt.

Marketing. Markets the majority of our natural gas and oil production, manages the associated commodity price risks and manages our remaining historical trading portfolio.

Power. Manages the risks associated with our remaining international power assets, primarily in Brazil, Asia and Central America. We continue to pursue the sale of certain of these assets.

Table of Contents

Our management uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income from continuing operations for the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Segment EBIT	$ 432	$ 324	$ 1,432	$ 1,552
Corporate and other EBIT	51	(17)	(263)	(51)
Interest and debt expense	(228)	(294)	(742)	(941)
Income taxes	(100)	98	(151)	(14)
Income from continuing operations	$ 155	$ 111	$ 276	$ 546

The following table reflects our segment results for each of the periods ended September 30:

	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other(1)	Total
	(In millions)					
Quarter Ended September 30, 2007						
Revenue from external customers	$572	$ 290(4)	$ 284	$	$ 20	$1,166
Intersegment revenue	14	285(4)	(293)		(6)	
Operation and maintenance	199	106	4	5	34	348
Depreciation, depletion, and amortization	94	194		1	4	293
Earnings (losses) from unconsolidated affiliates	28	2		(36)(2)		(6)
EBIT	275	232	(8)	(67)(2)	51(3)	483
2006						
Revenue from external customers	$567	$ 186(4)	$ 162	$ 1	$ 26	$ 942
Intersegment revenue	15	270(4)	(267)	2	(20)	
Operation and maintenance	198	109	6	14	7	334

Depreciation, depletion, and amortization	92	163	1		4	260
Earnings from unconsolidated affiliates	25	2		28		55
EBIT	253	141	(108)	38	(17)	307

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. During the quarter ended September 30, 2007, we recorded an intersegment revenue elimination of $6 million, and for the quarter ended September 30, 2006, we recorded an intersegment revenue elimination of $19 million and an operation and maintenance expense elimination of $13 million, which is included in the Corporate and other column to remove

intersegnment transactions.

(2) Includes a loss associated with our equity investment in and note receivable from the Porto Velho project, which is further discussed in Note 11.

(3) Includes a $77 million gain associated with the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business which is further discussed in Note 7.

(4) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing the majority of our production.

Table of Contents

	Segments Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
	(In millions)					
Nine Months Ended September 30, 2007						
Revenue from external customers	$1,803	$ 778(4)	$ 744	$	$ 61	$3,386
Intersegment revenue	41	877(4)	(904)		(14)	
Operation and maintenance	541	326	7	16	88	978
Depreciation, depletion, and amortization	279	553	2	1	15	850
Earnings (losses) from unconsolidated affiliates	83	4		(12)[2]		75
EBIT	957	646	(138)	(33)[2]	(263)[3]	1,169
2006						
Revenue from external customers	$1,759	$ 501(4)	$1,015	$ 4	$ 89	$3,368
Intersegment revenue	46	883(4)	(897)	2	(34)	
Operation and maintenance	540	295	18	44	60	957
Depreciation, depletion, and amortization	278	465	3	1	19	766
Earnings (losses) from unconsolidated affiliates	69	10		43	(1)	121
EBIT	885	503	113	51	(51)	1,501

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. During the nine

months ended September 30, 2007, we recorded an intersegment revenue elimination of $15 million, and for the nine months ended September 30, 2006, we recorded an intersegment revenue elimination of $32 million and an operation and maintenance expense elimination of $13 million, which is included in the Corporate column to remove intersegment transactions.

(2) Includes a loss associated with our equity investment in and note receivable from the Porto Velho project, which is further discussed in Note 11.

(3) Debt and treasury management activities, which are part of Corporate and Other, includes debt extinguishment

costs of $287 million, $86 million of which related to refinancing EPEP s $1.2 billion notes. This amount also includes a $77 million gain associated with the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business, which is further discussed in Note 7.

(4) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing the majority of our production.

Total assets by segment are presented below:

	September 30, 2007	December 31, 2006
	(In millions)	

Pipelines	$ 13,599	$ 13,105
Exploration and Production	7,814	6,262
Marketing	499	1,143
Power	563	618
Total segment assets	22,475	21,128
Corporate and Other	1,606	2,000
Discontinued operations		4,133
Total assets	$ 24,081	$ 27,261

Table of Contents

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

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. The earnings from unconsolidated affiliates reflected in our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) any impairments and other adjustments recorded by us. The information below related to our unconsolidated affiliates includes (i) our net investment and earnings (losses) we recorded from these investments, (ii) summarized financial information of our proportionate share of these investments, and (iii) revenues and charges with our unconsolidated affiliates.

Net investment and earnings (losses)	**Investment**		**Earnings (Losses) from Unconsolidated Affiliates**			
			Quarters Ended		**Nine Months Ended**	
	September 30, 2007	**December 31, 2006**	**September 30, 2007**	**2006**	**September 30, 2007**	**2006**
	(In millions)		**(In millions)**			
Domestic:						
Four Star[1]	$ 708	$ 723	$ 2	$ 2	$ 4	$ 10
Citrus	560	597	21	19	65	48
Other	38	36	2	11	3	15
Foreign:						
Bolivia to Brazil Pipeline	110	105	3	5	8	10
Manaus/Rio Negro	81	96	(7)	4	2	15
Porto Velho[2]	(60)	(34)	(31)	2	(24)	1
Asian and Central American Investments[2]	26	27		2	(1)	(3)
Other[2]	175	157	4	10	18	25
Total	$ 1,638	$ 1,707	$ (6)	$ 55	$ 75	$ 121

(1) During the third quarter of 2007, we increased our ownership interest in Four Star from 43 percent to 49 percent. Amortization of our purchase cost in excess of the underlying net assets of Four Star was $10 million and $13 million for the quarters ended September 30, 2007 and 2006 and $37 million and

$40 million for the nine months ended September 30, 2007 and 2006. For a further discussion, see our 2006 Annual Report on Form 10-K.

(2) As of September 30, 2007 and December 31, 2006, we had outstanding advances and receivables of $349 million and $380 million related to our foreign investments of which $335 million and $350 million related to our investment in Porto Velho. Earnings above do not reflect income (loss) recognized on these outstanding advances and receivables of approximately $(24) million and $11 million for the quarters ended September 30, 2007 and 2006 and less than $1 million and $34 million for the nine months ended September 30, 2007 and 2006. For further information, see the Porto Velho discussion below.

	Quarters Ended September 30,		Nine Months Ended September 30,	
Summarized Financial Information	**2007**	**2006**	**2007**	**2006**
	(In millions)			
Operating results data:				
Revenues	$222	$276	$638	$896

Operating expenses	132	138	375	619
Income from continuing operations	51	92	164	121
Net income[(1)]	51	92	164	121

(1) Includes net income of less than $1 million and $2 million for the quarters ended September 30, 2007 and 2006, and $9 million and $11 million for the nine months ended September 30, 2007 and 2006, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

We received distributions and dividends of $35 million and $61 million for the quarters ended September 30, 2007 and 2006 and $173 million and $137 million for the nine months ended September 30, 2007 and 2006. Included in these amounts are returns of capital of less than $1 million and $17 million for the quarter and nine months ended September 30, 2007 and less than $1 million for the quarter and nine months ended September 30, 2006.

Revenues and charges with unconsolidated affiliates	Quarter Ended September 30, 2007	Quarter Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)			
Operating revenue	$ 1	$ 1	$4	$61
Operating expense	2		4	2
Other income		2	2	5
Interest income	(24)[(1)]	11		34

(1) Included is an impairment of our Porto Velho note receivable as further described below.

Matters that Could Impact Our Investments

Porto Velho. We have an equity investment in and a note receivable from the Porto Velho project in Brazil. The power generated by the Porto Velho project is committed to a state-owned utility under power purchase agreements, the largest of which extends through 2023. In July 2007, we received an offer from our partner to purchase our investment in the project for less than its overall carrying value, but a decision to sell our investment has not been made at this time. The power markets in Brazil continue to evolve and mature, and during the third quarter of 2007, the Brazilian national power grid operator communicated to Porto Velho s management that its power plant (and the region that the plant serves) will be interconnected to an integrated power grid in Brazil as soon as late 2008. When the interconnection is completed, the state-owned utility will have access to sources of power at rates that may be less than the price under Porto Velho s existing power purchase agreements. Furthermore, there are plans to construct new hydroelectric plants in northern Brazil that could reportedly be completed as early as 2012 which, once connected to the grid, could further reduce regional power prices and the amount of power Porto Velho will be able to sell under its power purchase agreements. Based on our assessment of the impact these ongoing developments may have on northern Brazil s electricity markets and Porto Velho s power purchase agreements, we recorded incremental losses on our investment during the third quarter of 2007 of approximately $32 million. We also recorded a $25 million impairment of our note receivable from the project, and have discontinued accruing interest on the note. After these adjustments, our total investment in the Porto Velho project was approximately $275 million as of September 30, 2007, comprised primarily of the note receivable from the project. During the fourth quarter of 2007, we will be required to convert approximately $80 million of the amounts due under this note into an equity investment in the project. In addition, we may be required to convert up to an additional $80 million of the note, depending on the level of equity that our partner contributes to the project, which would increase our percentage ownership in Porto Velho. Further adverse developments in the Brazilian power markets or at the project could impact our ability to recover our remaining investment in the future.

In addition, in December 2006 the Brazilian tax authorities assessed a $30 million fine against the Porto Velho power project for allegedly not filing the proper tax forms related to the delivery of fuel to the power facility under its power purchase agreements. We believe the claim by the tax authorities is without merit.

Manaus/Rio Negro. As of September 30, 2007, our total investment and guarantees related to the Manaus and Rio Negro projects were approximately $83 million. During the third quarter of 2007, we impaired our investments in these projects by approximately $7 million as a result of mechanical failures at the plants. We have an agreement to transfer our ownership in these facilities to the power purchaser in January 2008, and a dispute has arisen with the purchaser about whether certain maintenance should be performed at the plants prior to the transfer. Although the outcome of the dispute is unknown at this time, an unfavorable outcome could negatively impact our ability to recover our remaining investment in these projects.

Asian and Central American power investments. As of September 30, 2007, our total investment (including advances to the projects) and guarantees related to these projects was approximately $77 million. We are in the process of selling these assets. Any changes in the political and economic conditions could negatively impact the amount of net proceeds we expect to receive upon their sale, which may result in additional impairments.

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of September 30, 2007, our total investment and guarantees related to this pipeline project was approximately $122 million, of which the Bolivian portion was $3 million. In 2006, the Bolivian government announced a decree significantly increasing its interest in and control over Bolivia s oil and gas assets. We continue to monitor and evaluate, together with our partners, the potential commercial impact that these political

Table of Contents

events in Bolivia could have on our investment. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Investment in Argentina. We own an approximate 22 percent interest in the Argentina to Chile pipeline. As of September 30, 2007, our total investment in this pipeline project was approximately $25 million. In July 2006, the Ministry of Economy and Production in Argentina issued a decree that significantly increases the export taxes on natural gas. We continue to evaluate, together with our partners, the potential commercial impact that this and other decrees could have on the Argentina to Chile pipeline. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Table of Contents

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2006 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

Financial Update. During the first nine months of 2007, our pipeline operations continued to provide a strong base of earnings and cash flow and make progress on expansion projects. In 2007, we completed several expansions including Phase I of our Cypress project, our Louisiana Deepwater Link project, Triple-T Extension project and our Northeast Connexion New England project. We continue to make progress towards completing FERC approved expansions including the Essex Middlesex, WIC Kanda lateral and related compression, Medicine Bow, Elba Island LNG and Elba Express Pipeline expansion projects. In our exploration and production business, we acquired Peoples Energy Production Company in September 2007 and continued to execute on our capital programs. Average daily production was within our expected production range for the third quarter of 2007 and has increased eight percent comparing the nine months ended September 30, 2007 to the same period in 2006, excluding our equity investment in Four Star. Our year to date 2007 financial results were also marked by several significant events including (i) the completion of the sale of ANR and related assets in which we recorded a gain of approximately $0.6 billion and (ii) the repurchase or refinancing of approximately $5 billion of debt on which we recorded approximately $0.3 billion of losses on the extinguishment of certain of these obligations.

We have strengthened our credit metrics in 2007 through various financing activities including debt repurchases and refinancings. The refinancings provide us a lower cost of capital and investment grade covenants on that debt. Our credit ratings were upgraded by both Moody s and Standard & Poor s, while maintaining a positive outlook, and Fitch Ratings initiated coverage on El Paso in the first quarter of 2007. For further information on our debt obligations and changes to our credit ratings, see our Liquidity and Capital Resources discussion.

What to Expect Going Forward. In our pipeline operations, we will continue to focus on expansion projects in our primary growth areas and anticipate that our pipeline operations will continue to provide strong operating results for the remainder of the year based on the current levels of contracted capacity, continued success in re-contracting, expansion plans in our market and supply areas and rate and regulatory actions.

We are currently pursuing the formation of a master limited partnership (MLP) to enhance the value and financial flexibility of our pipeline assets and provide a lower-cost source of capital for new projects. We have filed a registration statement with the Securities and Exchange Commission that has not yet become effective relating to a proposed initial public offering of common units of our MLP, El Paso Pipeline Partners, L.P. If this offering is completed, we would contribute to the MLP 100% of Wyoming Interstate Company, Ltd. (our wholly owned interstate pipeline transportation business located primarily in Wyoming and Colorado) and 10 percent equity interests in Colorado Interstate Gas Company and Southern Natural Gas Company (excluding Citrus, Southern LNG, Inc. and Elba Express Company, LLC). At or prior to closing of the offering, CIG and SNG will distribute certain entities and assets to us. We will serve as the general partner of the MLP and continue to operate these assets. For further information regarding this offering of common units, see Part II, Item 1A, Risk Factors.

In our exploration and production business, we will continue to create value through a disciplined and balanced capital investment program, through active management of the cost of production services, portfolio management and a focus on delivering reserves and volumes at reasonable finding and operating costs. We will continue to evaluate opportunities to acquire properties, as shown by our acquisition of Peoples, that are tightly focused around our core competencies and areas of competitive advantage. Additionally, we are beginning a process to upgrade our portfolio by selling selected non-core properties that no longer meet our strategic objectives. While we do not anticipate exiting any region, our divestitures could total approximately 10 percent of our December 31, 2006 proved reserve base and will be weighted towards the Gulf of Mexico and south Texas areas. Our future financial results in this business will be primarily dependent on continued successful execution of our capital programs. These results may also be impacted by changes in commodity prices to the extent our anticipated natural gas and oil production is unhedged. We have currently hedged a substantial portion of our remaining anticipated 2007 and 2008 natural gas production and continue to evaluate opportunities to effectively manage our commodity price risk going forward.

Table of Contents

Segment Results

Below are our results of operations, as measured by earnings before interest expense and income taxes (EBIT) by segment. Our business segments consist of our Pipelines, Exploration and Production, Marketing and Power segments. These segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets, all of which are immaterial.

Our management uses EBIT to assess the operating results and effectiveness of our business segments, which consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT (by segment) to our consolidated net income for the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Segment				
Pipelines	$ 275	$ 253	$ 957	$ 885
Exploration and Production	232	141	646	503
Marketing	(8)	(108)	(138)	113
Power	(67)	38	(33)	51
Segment EBIT	432	324	1,432	1,552
Corporate and other	51	(17)	(263)	(51)
Consolidated EBIT	483	307	1,169	1,501
Interest and debt expense	(228)	(294)	(742)	(941)
Income taxes	(100)	98	(151)	(14)
Income from continuing operations	155	111	276	546
Discontinued operations, net of income taxes		24	674	95
Net income	$ 155	$ 135	$ 950	$ 641

Table of Contents

Pipelines Segment

Operating Results. Below is a discussion of the operating results for our Pipelines segment:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions, except volume amounts)			
Operating revenues	$ 586	$ 582	$ 1,844	$ 1,805
Operating expenses	(352)	(361)	(1,010)	(1,012)
Operating income	234	221	834	793
Other income	41	32	123	92
EBIT	$ 275	$ 253	$ 957	$ 885
Throughput volumes (BBtu/d)[1]	18,512	17,770	17,909	17,021

(1) Throughput volumes include volumes associated with our proportionate share of unconsolidated affiliates.

The table below outlines the variances in our operating results for the quarter and nine months ended September 30, 2007 as compared to the same periods in 2006:

	Quarter Ended September 30, 2007 Variance				Nine Months Ended September 30, 2007 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 14	$ (3)	$ 1	$ 12	$ 33	$ (6)	$ 5	$ 32
Reservation and usage revenues	8			8	13			13
Bankruptcy settlements	(14)	(4)		(18)	(2)	(4)		(6)
Operational gas and revaluations	(3)	8		5	(10)			(10)
Hurricanes Katrina and Rita		3		3		14		14
Losses on development projects		16		16		12		12
Equity earnings from Citrus			3	3			18	18

Other[(1)]	(1)	(11)	5	(7)	5	(14)	8	(1)
Total impact on EBIT	$ 4	$ 9	$ 9	$ 22	$ 39	$ 2	$ 31	$ 72

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

Expansions. During the quarter and nine months ended September 30, 2007, our reservation revenues and throughput volumes were higher than the same periods in 2006 primarily due to the Elba Island LNG, Piceance Basin and Cheyenne Plains Yuma Lateral expansion projects completed during 2006. In May 2007, we placed Phase I of the Cypress pipeline into service which is anticipated to generate annual EBIT of approximately $32 million. In July 2007, we completed the Louisiana Deepwater Link project which is anticipated to increase gas supply attached to our TGP system, over time, by up to one Bcf/d. In September 2007, we completed the Triple-T Extension project which is also anticipated to increase gas supply related to our TGP system. Revenues for the Louisiana Deepwater Link project and Triple-T Extension project will be based on throughput levels as natural gas reserves are developed. In November 2007, we placed the Northeast Connexion New England expansion project into service.

We continue to make progress on growth projects and have several expansion projects approved by the FERC in various stages of construction including our Essex Middlesex, WIC Kanda lateral and related compression, and Medicine Bow expansion projects. We anticipate that these projects will be placed in service in 2008. In September 2007, we received FERC approval for the expansion of the Elba Island LNG receiving terminal and the construction of the Elba Express Pipeline. The Elba Island LNG expansion is anticipated to increase the peak sendout capacity of the terminal from 1.2 Bcf/d to 2.1 Bcf/d. The Elba Express Pipeline will consist of approximately 190 miles of pipeline with a total capacity of 1.2 Bcf/d, which will transport natural gas from the Elba Island LNG terminal to markets in the southeastern and eastern United States.

Reservation and Usage Revenues. During 2007, our EBIT was favorably impacted by an increase in overall reservation and usage revenues. Throughput on our pipeline systems, primarily in the Rocky Mountains and southern regions, increased due to new supply, colder weather and transportation services to power plants. During 2007, we also benefited from additional firm capacity sold in the south central region on our TGP system and increased rates on our CIG system that went into effect in October 2006 as a result of its most recent rate case. Partially offsetting these favorable impacts were an increased provision for rate refund on our EPNG system and expiration of certain firm transportation contracts on our Mojave and SNG systems.

Table of Contents

Bankruptcy Settlements. In the second quarter of 2007, we received $10 million to settle our bankruptcy claim against USGen New England, Inc. During the third quarter of 2006 and the second quarter of 2007, we recorded income of approximately $18 million and $2 million, respectively net of amounts owed to certain customers, as a result of the Enron bankruptcy settlement.

Operational Gas and Revaluations. Our net gas imbalances and other gas owed to customers are revalued each period. During the nine months ended September 30, 2007, our EBIT decreased from the same period in 2006 due to these revaluations. During 2007, higher natural gas prices unfavorably impacted our results. Additionally, natural gas prices decreased during 2006 favorably impacting our results during that period. We anticipate that the overall activity in this area will continue to vary based on factors such as volatility in natural gas prices, the efficiency of our pipeline operations, regulatory actions and other factors.

Hurricanes Katrina and Rita. During 2007, we incurred lower operation and maintenance expenses to repair damage caused by Hurricanes Katrina and Rita as compared to 2006. For a further discussion of the impact of these hurricanes on our capital expenditures, see Liquidity and Capital Resources.

Losses on Development Projects. For the nine months ended September 30, 2007, we expensed costs of approximately $5 million associated with a storage project that we are no longer developing. During the third quarter of 2006, we discontinued our Continental Connector pipeline project and our Seafarer project and recorded a loss on these projects of approximately $16 million due to changing market conditions.

Equity Earnings from Citrus. During the first nine months of 2007, equity earnings on our Citrus investment increased primarily due to (i) a favorable settlement of approximately $8 million for litigation brought against Spectra LNG Sales (formerly Duke Energy LNG Sales, Inc.) for the wrongful termination of a gas supply contract; (ii) Citrus sale of a receivable for approximately $3 million related to the bankruptcy of Enron North America and (iii) favorable operating results of approximately $4 million from Florida Gas Transmission Company, a pipeline owned 100 percent by Citrus, due to higher system usage.

Regulatory Matters/Rate Cases. Our pipeline systems periodically file for changes in their rates, which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to impact our profitability.

EPNG In August 2007, EPNG received approval of the settlement of its rate case from the FERC. The settlement provides benefits for both EPNG and its customers for a three year period ending December 31, 2008. Under the terms of the settlement, EPNG is required to file a new rate case to be effective January 1, 2009. EPNG has received approval from the FERC to begin billing the settlement rates on October 1, 2007 and it will refund amounts, with interest, within 120 days of that date. Our financial statements reflect EPNG s proposed rates and we have reserved a sufficient amount to meet the refund obligations under this settlement. For a further discussion, see Item 1, Financial Statements, Note 7.

Mojave Pipeline (MPC) In February 2007, as required by its prior rate case settlement, MPC filed with the FERC a general rate case proposing a 33 percent decrease in its base tariff rates resulting from a variety of factors, including a decline in rate base and various changes in rate design since the last rate case. No new services were proposed. We anticipate a decrease in revenues of approximately $13 million annually due to these rate changes. The new base rates were effective March 1, 2007 and are subject to further adjustment upon the outcome of the rate case proceeding. In October 2007, MPC filed an offer of settlement to resolve all issues in the rate case. The offer has either been supported or unopposed by all participants, and the Presiding Judge over the preceding has certified the settlement offer to the FERC for its review.

CIG/WIC In August 2007, CIG filed a tariff change with the FERC to modify its fuel recovery mechanism to recover all cost impacts, or flow through to shippers any revenue impacts, of all fuel imbalance revaluations and related gas balance items. CIG currently experiences variability in cash flow and earnings under its fuel recovery mechanism, but its earnings variability related to price fluctuations will be substantially reduced if the FERC approves the fuel tracker. This tariff filing was protested by certain shippers and the FERC has suspended the effective date to March 1, 2008 subject to the outcome of a technical conference on the proposed tariff change that is scheduled for November 2007. In addition, WIC filed a tariff change with the FERC in September 2007 to establish a fuel and related gas balance recovery mechanism, which if approved, will recover all cost impacts, or flow through to shippers any revenue impacts of all such items. This tariff filing was protested by certain shippers and the FERC has suspended the effective date to April 1, 2008, subject to the outcome of a technical conference on the proposed tariff change, which has not been scheduled.

Table of Contents

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance in this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management.

Our domestic natural gas and oil reserve portfolio blends slower decline rate, typically longer lived assets in our Onshore region, with steeper decline rate and shorter lived assets in our Texas Gulf Coast and Gulf of Mexico Shelf/south Louisiana regions. We believe the combination of our assets in these regions provides significant near-term cash flows while providing consistent opportunities for competitive investment returns. In addition, our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and longer term cash flows. We will continue to evaluate acquisition and growth opportunities that are tightly focused around our core competencies and areas of competitive advantage. Additionally, we have begun the process of upgrading our portfolio by selling selected non-core properties that no longer meet our strategic objectives. While we do not anticipate exiting any region, our divestitures could total approximately 10 percent of our December 31, 2006 proved reserve base and will be weighted towards the Gulf of Mexico and south Texas areas. For a further discussion of our business and strategy, see our 2006 Annual Report on Form 10-K.

In September 2007, we acquired Peoples for total cash consideration of $879 million. Peoples natural gas and oil properties are located primarily in the ArkLaTex, Texas Gulf Coast and Mississippi areas and the San Juan and Arkoma Basins.

Operating Results for the Periods Ended September 30, 2007

Average Daily Production. Our average daily production for the nine months ended September 30, 2007, was 774 MMcfe/d (excluding 67 MMcfe/d from our equity investment in Four Star). Average daily production was within our expected production range for the third quarter of 2007 and, excluding our equity investment in Four Star, increased eight percent for the nine months ended September 30, 2007 compared with the same period in 2006. Below is an analysis of our production by region for the periods ended September 30:

	Nine Months Ended September 30,	
	2007	**2006**
	(MMcfe/d)	
United States		
Onshore	364	342
Texas Gulf Coast	199	189
Gulf of Mexico Shelf /south Louisiana	196	162
International		
Brazil	15	26
Total Consolidated	774	719
Four Star[1]	67	67

[1] Amounts represent our proportionate share of the production of Four Star.

We have increased production volumes across all of our domestic operating regions. In our Onshore region, our 2007 production continued to increase through capital projects where we maintained or increased production in most of our major operating areas, with the majority of growth coming from the Rockies and ArkLaTex areas. In the Texas Gulf Coast region, the acquisition of properties in Zapata County during the first quarter of 2007 and success of our subsequent drilling program more than offset natural production declines and the sale of certain non-strategic south Texas properties in 2006. In the Gulf of Mexico Shelf/south Louisiana region, we began producing from development wells in the western gulf and south Louisiana and several exploratory discoveries occurring prior to 2007. We also recovered volumes shut-in by hurricane damage, which when coupled with these new production sources, helped to offset natural production declines. In Brazil, production volumes decreased due to natural production declines and a contractual reduction of our ownership interest in the Pescada-Arabaiana fields in early 2006.

Table of Contents

Drilling

The following is a discussion of our drilling results for the nine months ended September 30, 2007:

Onshore. We realized a 100 percent success rate on 469 gross wells drilled.

Texas Gulf Coast. We experienced a 90 percent success rate on 61 gross wells drilled.

Gulf of Mexico Shelf /south Louisiana. We drilled four successful wells and six unsuccessful wells.

Brazil. We completed drilling two successful exploratory wells south of the Pinauna Field in the BM-CAL-4 concession in the Camamu Basin that extend the southern limits of the Pinauna project. We are currently evaluating test results and assessing development options. We currently own 100 percent of the BM-CAL-4 concession and are in the process of marketing up to a 50 percent non-operating interest in this concession. In addition, we completed drilling and testing an exploratory well with Petrobras in the ES-5 Block in the Espirito Basin. This well confirmed the extension of an earlier discovery by Petrobras on a block to the south and we have begun drilling an appraisal well on the ES-5 Block to further delineate this structure.

Egypt. In April 2007, we received formal government approval and signed the concession agreement for the South Mariut Block. We paid $3 million for the concession and agreed to a $22 million firm working commitment over three years. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta.

Cash Operating Costs. We monitor the cash operating costs required to produce our natural gas and oil volumes. These costs are generally reported on a per Mcfe basis and include total operating expenses less depreciation, depletion and amortization expense and cost of products and services on our income statement. During the nine months ended September 30, 2007, cash operating costs per unit increased to $1.89/Mcfe as compared to $1.85/Mcfe for the same period in 2006, primarily as a result of higher workover activity levels, industry inflation in services, labor and material costs, lower severance tax credits, higher marketing and other costs and higher corporate overhead allocations.

Capital Expenditures. Our total natural gas and oil capital expenditures on an accrual basis were approximately $2 billion for the nine months ended September 30, 2007, including $879 million for our Peoples acquisition in September 2007, $254 million to acquire producing properties and undeveloped acreage in Zapata County, Texas in January 2007 and $27 million to increase our ownership interest in Four Star from 43 percent to 49 percent. The Peoples acquisition complements our operations in the ArkLaTex and Texas Gulf Coast areas while the acquisition in Zapata County complements our existing Texas Gulf Coast operations and provides a re-entry into the Lobo area.

Outlook

For the full year 2007, we anticipate the following on a worldwide basis:

- Average daily production volumes of approximately 785 MMcfe/d to 800 MMcfe/d, which excludes approximately 65 MMcfe/d to 70 MMcfe/d from our equity investment in Four Star;

- Total capital expenditures, excluding acquisitions, between $1.4 billion and $1.5 billion. While more than 80 percent of the 2007 capital program is allocated to our domestic program, we have invested approximately $179 million internationally through September 2007, primarily in our Brazil exploration and development program;

- Average cash operating costs which include production costs, general and administrative expenses and taxes (other than production and income) of approximately $1.85/Mcfe to $1.95/Mcfe; and

- An overall depreciation, depletion, and amortization rate between $2.60/Mcfe and $2.75/Mcfe.

Table of Contents

Price Risk Management Activities

As part of our strategy, we enter into derivative contracts on our natural gas and oil production to stabilize cash flows, to reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. Because this strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. Adjustments to our hedging 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 nine months ended September 30, 2007, we entered into floor and ceiling option contracts, 77 TBtu of basis swaps and 28 TBtu of fixed price swaps, all related to anticipated 2008 natural gas production. The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts when combined with the sale of the underlying hedged production as of September 30, 2007:

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)			
							Texas Gulf Coast		Onshore-Raton	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas										
2007	22	$ 7.66	14	$8.00	14	$16.89	20	$ (0.66)	7	$ (1.09)
2008	33	$ 7.65	104	$8.00	104	$10.82	51	$ (0.33)	26	$ (1.13)
2009	5	$ 3.56								
2010-2012	11	$ 3.81								
Oil										
2007	48	$35.15								

(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.

In October 2007, we entered into additional derivative contracts, which include (i) swaps at a fixed price of $8.00 per MMBtu on approximately 8 TBtu of anticipated 2007 natural gas production, (ii) option contracts on approximately 4 TBtu of anticipated 2008 natural gas production at a floor price of $8.00 per MMBtu and a ceiling price of $10.00 per MMBtu and (iii) basis swaps on 15 TBtu of anticipated 2009 natural gas production in the Onshore-Raton area.

Most of our floor and ceiling option contracts are designated as accounting hedges. Gains and losses associated with these natural gas contracts are deferred in accumulated other comprehensive income and will be recognized in earnings upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. Our oil fixed price swaps and approximately 9 TBtu, 11 TBtu and 90 TBtu of our natural gas fixed price swaps, option contracts and basis swaps are not designated as accounting hedges. Accordingly, changes in the fair value of these derivatives are not deferred, but are recognized in earnings each period.

Additionally, the table above does not include (i) net realized gains on derivative contracts previously accounted for as hedges on which we will record an additional $15 million as natural gas and oil revenues for the remainder of 2007, which are also currently deferred in accumulated other comprehensive income or (ii) contracts entered into by our Marketing segment as further described in that segment. For the consolidated impact of the entirety of El Paso s production-related price risk management activities on our liquidity, see the discussion of factors that could impact our liquidity in Liquidity and Capital Resources.

Table of Contents

Financial Results and Analysis

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Operating Revenues:				
Natural gas	$ 431	$ 357	$ 1,298	$ 1,049
Oil, condensate and NGL	129	119	328	327
Other	15	(20)	29	8
Total operating revenues	575	456	1,655	1,384
Operating Expenses:				
Depreciation, depletion and amortization	(194)	(163)	(553)	(465)
Production costs	(79)	(92)	(249)	(235)
Cost of products and services	(25)	(23)	(68)	(67)
General and administrative expenses	(46)	(38)	(141)	(121)
Other	(3)	(2)	(10)	(6)
Total operating expenses	(347)	(318)	(1,021)	(894)
Operating income	228	138	634	490
Other income[(1)]	4	3	12	13
EBIT	$ 232	$ 141	$ 646	$ 503

(1) Includes equity earnings from our investment in Four Star.

	Quarters Ended September 30,			Nine Months Ended September 30,		
	2007	2006	Percent Variance	2007	2006	Percent Variance
Consolidated volumes, prices and costs per unit:						
Natural gas						
Volumes (MMcf)	60,705	56,736	7%	177,222	162,403	9%
Average realized prices including hedges ($/Mcf)	$ 7.12	$ 6.30	13%	$ 7.33	$ 6.46	13%
Average realized prices excluding hedges ($/Mcf)	$ 5.92	$ 6.31	(6)%	$ 6.52	$ 6.79	(4)%
Average transportation costs ($/Mcf)	$ 0.29	$ 0.23	26%	$ 0.28	$ 0.23	22%
Oil, condensate and NGL						
Volumes (MBbls)	1,948	1,959	(1)%	5,684	5,662	%
Average realized prices including hedges ($/Bbl)	$ 66.26	$ 60.81	9%	$ 57.71	$ 57.81	%

Average realized prices excluding hedges ($/Bbl)	$ 66.82	$ 60.81	10%	$ 58.36	$ 58.22	%
Average transportation costs ($/Bbl)	$ 0.84	$ 0.71	18%	$ 0.76	$ 0.91	(16)%
Total equivalent volumes						
MMcfe	72,392	68,490	6%	211,327	196,376	8%
MMcfe/d	787	744	6%	774	719	8%
Production costs and other cash operating costs ($/Mcfe)						
Average lease operating cost	$ 0.83	$ 1.03	(19)%	$ 0.87	$ 0.89	(2)%
Average production taxes[(1)]	0.26	0.32	(19)%	0.31	0.31	%
Total production cost	1.09	1.35	(19)%	1.18	1.20	(2)%
Average general and administrative cost	0.64	0.57	12%	0.67	0.62	8%
Average taxes, other than production and income	0.04	0.03	33%	0.04	0.03	33%
Total cash operating costs	$ 1.77	$ 1.95	(9)%	$ 1.89	$ 1.85	2%
Unit of production depletion cost ($/Mcfe)	$ 2.56	$ 2.27	13%	$ 2.50	$ 2.24	12%
Unconsolidated affiliate volumes (Four Star)						
Natural gas (MMcf)	4,107	4,379		13,854	13,342	
Oil, condensate and NGL (MBbls)	254	278		756	847	
Total equivalent volumes						
MMcfe	5,634	6,049		18,389	18,424	
MMcfe/d	61	66		67	67	

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

32

Table of Contents

The table below outlines the variances in our operating results for the quarter and nine months ended September 30, 2007 as compared to the same periods in 2006:

	Quarter Ended September 30, 2007				Nine Months Ended September 30, 2007			
	Variance				Variance			
	Operating Revenue	Operating Expense	Other	EBIT	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)							
Natural Gas Revenue								
Lower realized prices in 2007	$ (23)	$	$	$ (23)	$ (48)	$	$	$ (48)
Impact of hedges	72			72	196			196
Higher volumes in 2007	25			25	101			101
Oil, Condensate and NGL Revenue								
Higher realized prices in 2007	12			12	1			1
Impact of hedges	(1)			(1)	(1)			(1)
Higher (lower)volumes in 2007	(1)			(1)	1			1
Other Revenue								
Change in fair value of derivatives not designated as accounting hedges	50			50	45			45
Other	(15)			(15)	(24)			(24)
Depreciation, Depletion and Amortization Expense								
Higher depletion rate in 2007		(22)		(22)		(55)		(55)
Higher production volumes in 2007		(8)		(8)		(33)		(33)
Production Costs								
Lower (higher) lease operating costs in 2007		10		10		(11)		(11)
Lower (higher) production taxes in 2007		3		3		(3)		(3)
General and Administrative Expenses		(8)		(8)		(20)		(20)
Other								
Earnings from investment in Four Star							(6)	(6)
Other		(4)	1	(3)		(5)	5	
Total Variances	$ 119	$ (29)	$ 1	$ 91	$ 271	$ (127)	$ (1)	$ 143

Operating revenues. During 2007, revenues increased compared with 2006 primarily due to higher realized natural gas prices, including the effects of our hedging program. Realized gains on hedging transactions were $71 million and $140 million during the quarter and nine months ended September 30, 2007, as compared to losses of less than $1 million and $55 million for the quarter and nine months ended September 30, 2006. During both periods in 2007, we also benefited from an increase in production volumes over 2006.

Other revenue. During the quarter and nine months ended September 30, 2007, we recognized mark-to-market gains of $7 million and $4 million as compared to losses of $43 million and $41 million for the same periods in 2006 related to the change in fair value of derivatives not designated as hedges including a portion of our oil and natural gas fixed-price swaps, option contracts and basis swaps.

Depreciation, depletion and amortization expense. During 2007, our depletion rate increased as compared to the same periods in 2006 as a result of downward revisions in previous estimates of reserves due to lower commodity prices and higher finding and development costs. Finding and development costs in 2006 were higher due to mechanical problems experienced in executing our drilling program and service cost inflation.

Production costs. Our lease operating costs increased during the nine months ended September 30, 2007 as compared to the same period in 2006 due to higher workover activity levels, industry-wide cost inflation for services, labor and material costs and lower severance tax credits. Our lease operating costs decreased during the quarter ended September 30, 2007 as compared to the same period in 2006 primarily due to lower workover activity levels.

Table of Contents

General and administrative expenses. Our general and administrative expenses increased during the 2007 periods as compared to 2006 primarily due to higher labor costs, higher marketing and other costs previously in our Marketing segment, and higher corporate overhead allocations.

Marketing Segment

Overview. Our Marketing segment markets the majority of our Exploration and Production segment s natural gas and oil production and manages the company s overall commodity price risks, primarily through the use of natural gas and oil derivative contracts. This segment also manages our remaining legacy natural gas supply, transportation, power and other natural gas contracts entered into prior to our decision to exit the energy trading business. To the extent it is economical to do so, we may liquidate certain of these remaining legacy contracts before their expiration, which could affect our operating results in future periods. For a further discussion of our contracts in this segment including our expected earnings volatility by contract type, see our 2006 Annual Report on Form 10-K.

Operating Results. Our 2007 year-to-date results were primarily driven by mark-to-market losses on our legacy natural gas and power positions and on option contracts that were entered into to manage the price risk of the company s natural gas and oil production. These positions were negatively impacted by changes in commodity prices and decreases in interest rates used in determining their fair value. Our 2007 year-to-date losses were partially offset by $51 million of income recognized upon the sale of our investment in the NYMEX and the settlement of outstanding California power price disputes. Below is further information about our overall operating results during the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Gross Margin by Significant Contract Type:				
Production-Related Natural Gas and Oil Derivative Contracts:				
Changes in fair value of derivative contracts	$ 15	$ 67	$ (63)	$ 256
Contracts Related to Legacy Trading Operations:				
Natural gas transportation-related natural gas contracts:				
Demand charges	(27)	(28)	(82)	(97)
Settlements	18	15	54	52
Changes in fair value of other natural gas derivative contracts [(1)]	(4)	(186)	(26)	(157)
Changes in fair value of power contracts[(2)]	(11)	27	(43)	64
Total gross margin[(3)]	(9)	(105)	(160)	118
Operating expenses	(4)	(8)	(9)	(23)
Operating income (loss)	(13)	(113)	(169)	95
Other income, net[(4)]	5	5	31	18
EBIT	$ (8)	$ (108)	$ (138)	$ 113

(1) During the third quarter of 2006, we recognized a loss of

$133 million on our MCV natural gas supply agreements upon our Power segment s sale of its interest in that facility.

(2) Includes $2 million and $23 million of revenue during the quarter and nine months ended September 30, 2007, related to the settlement of outstanding California power price disputes.

(3) Gross margin consists of revenues from commodity marketing activities less costs of commodities sold, including changes in the fair value of derivative contracts.

(4) We recognized a $23 million gain on the sale of our investment in the NYMEX during the first quarter of 2007 and recognized $5 million of interest income during the third

quarter of 2007 related to the settlement of outstanding California power price disputes. Amounts in 2006 primarily represent interest on cash margin deposits.

Production-related Natural Gas and Oil Derivative Contracts

Option contracts. Our production-related natural gas and oil derivative contracts are designed to provide protection to El Paso against changes in natural gas and oil prices. These are in addition to those contracts entered into by our Exploration and Production segment which are further discussed in that segment. For the consolidated impact of all of El Paso s production-related price risk management activities, refer to our Liquidity and Capital Resources discussion. Our production-related derivatives consist of various option contracts which are marked-to-market in our results each period based on changes in commodity prices.

Table of Contents

Listed below are the volumes and average prices associated with our production-related derivative contracts as of September 30, 2007:

	Floors[1]		Ceilings[1]	
	Volumes	Average Price	Volumes	Average Price
Natural Gas				
2007[2]	22	$ 7.50		$
2008 [2]		$		$
2009	17	$ 6.00	17	$ 8.75
Oil				
2007	239	$55.00	239	$58.75
2008	930	$55.00	930	$57.03

(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) In the third quarter of 2007, we paid approximately $3 million to terminate our 2008 contracts. In October 2007, we also terminated 6 TBtu of our 2007 floors in connection with additional positions entered into by our Exploration and Production segment.

We experience volatility in our financial results based on changes in the fair value of our option contracts which generally move in the opposite direction from changes in commodity prices. During the nine months ended September 30, 2007, increases in commodity prices reduced the fair value of our option contracts resulting in a loss on these contracts. For the quarters ended September 30, 2007 and 2006 and the nine months ended September 30, 2006, decreases in commodity prices increased the fair value of our option contracts resulting in a gain on these contracts.

During the nine months ended September 30, 2007 and 2006, we received cash of approximately $42 million and $22 million on contracts that settled during the period.

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. As of September 30, 2007, our transportation contracts provide us with approximately 0.8 Bcf/d of pipeline capacity. Effective November 1, 2007, our Alliance capacity will transfer to a third party and our annual demand charges will average $46 million from 2008 to 2011. The recovery of demand charges and profitability of our transportation contracts is dependent upon our ability to use or remarket the contracted pipeline capacity, which is impacted by a number of factors as described in our 2006 Annual Report on Form 10-K. These transportation contracts are accounted for on an accrual basis and impact our gross margin as delivery or service under the contracts occurs. The following table is a summary of our demand charges (in millions) and our percentage of recovery of these charges for the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Alliance:				
Demand charges	$ 17	$16	$ 50	$48
Recovery	47%	72%	47%	53%
Other:				
Demand charges	$ 10	$12	$ 32	$49
Recovery	100%	25%	100%	54%

Other natural gas derivative contracts. In addition to our transportation-related natural gas contracts, we have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices. In 2006 we divested or entered into transactions to divest of a substantial portion of these natural gas contracts, which substantially reduced our future cash and earnings exposure to price movements on these contracts. During the first quarter of 2007, we assigned a weather call derivative which had required us to supply gas in the northeast region if temperatures fell to specific levels resulting in a charge of $13 million. During 2006, we recognized a $49 million gain associated with the assignment of certain natural gas derivative contracts to supply natural gas in the southeastern U.S. Also in 2006, our Power segment sold its interest in the MCV power plant. We continue to supply gas to MCV under natural gas supply contracts and in the third quarter of 2006 recorded a cumulative mark to market loss of approximately $133 million which had not been previously recognized due to our affiliated ownership interest.

Power Contracts. We currently have four power contracts that require us to swap locational differences in power prices between several power plants in the Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub and provide installed capacity in the PJM power pool through 2016. We recognized gains in 2006 primarily related to locational price differences in these regions as we had eliminated the commodity price risk associated with these contracts by the end of 2006. In 2007, the PJM Independent System Operator (ISO) conducted auctions in April, July and October to set prices for providing installed capacity to customers in the PJM power pool from June 2007 to May 2010. The fair value of our power contracts is impacted by changes in installed capacity prices, which are based in part on the result of these auctions. The fair value of our power contracts was also impacted by a dispute with a downstream purchaser with regard to the region within PJM that capacity must be made available. During the quarter ended September 30, 2007, we recorded a loss of approximately $7 million and for the nine months ended September 30, 2007 we recorded a loss of approximately $48 million primarily as a result of changing installed capacity prices. The results of future auctions, including one scheduled in January 2008, and other potential developments with our contracts and the PJM marketplace may possibly impact the fair value of our power contracts and result in future volatility in our operating results.

Power Segment

Our Power segment consists of assets in Brazil, Asia and Central America. We continue to pursue the sales of certain of our remaining power investments. As of September 30, 2007, our remaining investment, guarantees and letters of credit related to power projects in this segment totaled approximately $582 million which consisted of approximately $540 million in equity investments and notes receivable and approximately $42 million in financial guarantees and letters of credit, as follows (in millions):

Area	**Amount**
Brazil	
Porto Velho	$ 275
Manaus & Rio Negro	83
Pipeline projects	147
Asia & Central America	77
Total investment, guarantees and letters of credit	$ 582

Operating Results. Our Power segment generated EBIT losses of $67 million and $33 million for the quarter and nine months ended September 30, 2007. Our 2007 third quarter results were negatively impacted by losses of $57 million on our interests in Porto Velho and $7 million on our interest in the Manaus and Rio Negro project based on adverse developments at these projects. For a discussion of these developments and other matters that could impact our Brazilian investments, see Item 1, Financial Statements and Supplementary Data, Note 11.

In 2006, we generated EBIT of $38 million and $51 million for the quarter and nine month periods. Our third quarter 2006 operating results included a gain on the sale of our MCV project of $13 million and a gain on the sale of a cost basis investment of $12 million.

During each of the periods in 2006 and 2007, we did not recognize earnings from certain of our Asian and Central American investments based on our inability to realize earnings through the expected selling price of these assets. We continue to pursue the sale of our remaining investments in Asia and Central America and until these sales are completed, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in impairments of our investments.

Table of Contents

Corporate and Other Expenses, Net

Our corporate activities include our general and administrative functions as well as a number of miscellaneous businesses, which do not qualify as operating segments and are not material to our current period results. The following is a summary of significant items impacting EBIT in our corporate operations for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions)			
Loss on extinguishment of debt	$	$ (17)	$ (287)	$ (26)
Foreign currency fluctuations on Euro-denominated debt	(4)	2	(7)	(12)
Change in litigation, insurance and other liabilities	56	(18)	21	(60)
Other	(1)	16	10	47
Total EBIT	$ 51	$ (17)	$ (263)	$ (51)

Extinguishment of Debt. During 2007, we have repurchased or refinanced debt of approximately $5 billion. We recorded charges of $287 million in our income statement for the loss on extinguishment of these obligations, which included $86 million related to repurchasing EPEP s $1.2 billion notes. For further information on our debt, see Item 1, Financial Statements, Note 6.

Litigation, Insurance, and Other Liabilities. During the third quarter of 2007, we recorded a gain of approximately $77 million on the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business. For a further discussion of this matter, see Item 1, Financial Statements, Note 7. We have a number of other pending litigation matters, environmental matters and other reserves related to our historical business operations that also affect our corporate results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may further impact our future results. For further information on these matters, see Item 1, Financial Statements, Note 7.

Interest and Debt Expense

Interest and debt expense for the quarters and nine months ended September 30, 2007 decreased compared to the same periods in 2006 due primarily to the retirement (net of issuances) of approximately $2.6 billion of debt during 2006 and $1.7 billion in the first nine months of 2007.

Income Taxes

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In millions, except for rates)			
Income taxes	$100	$ (98)	$151	$14
Effective tax rate	39%	(754)%	35%	3%

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

Discontinued Operations

Income from our discontinued operations was $674 million and $95 million for the nine months ended September 30, 2007 and 2006 and $24 million for the quarter ended September 30, 2006. In February 2007, we sold ANR and related operations and recognized a gain of $648 million, net of taxes of $354 million.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item I, Financial Statements, Note 7 which is incorporated herein by reference.

37

Table of Contents

Liquidity and Capital Resources

Sources and Uses of Cash. Our primary sources of cash are cash flow from operations and amounts available to us under revolving credit facilities. On occasion and as conditions warrant, we may also generate funds through capital market activities and proceeds from asset sales. Our primary uses of cash are funding the capital expenditure programs of our pipeline and exploration and production operations, meeting operating needs, and repaying debt when due or repurchasing certain debt obligations when conditions warrant.

Overview of Cash Flow Activities. For the nine months ended September 30, 2007 and 2006, our cash flows from continuing operations are summarized as follows:

	2007	2006
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Income from continuing operations	$ 0.3	$ 0.5
Loss on debt extinguishment	0.3	
Other income adjustments	1.0	0.9
Change in other assets and liabilities	(0.1)	0.3
Total cash flow from operations	$ 1.5	$ 1.7
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.1	$ 0.5
Net change in restricted cash and other	0.1	0.1
	0.2	0.6
Continuing financing activities		
Net proceeds from the issuance of long-term debt	5.2	0.1
Contribution from discontinued operations	3.4	0.3
Net proceeds from the issuance of common stock		0.5
	8.6	0.9
Total other cash inflows	$ 8.8	$ 1.5
Cash Outflows		
Continuing investing activities		
Capital expenditures	$ 1.8	$ 1.5
Cash paid for acquisitions, net of cash acquired	1.2	
	3.0	1.5
Continuing financing activities		
Payments to retire long-term debt and other financing obligations	7.3	3.0

Dividends and other	0.1	0.1
	7.4	3.1
Total cash outflows	$ 10.4	$ 4.6
Net change in cash	$ (0.1)	$ (1.4)

During 2007, we generated positive operating cash flow of approximately $1.5 billion, primarily as a result of cash provided by our pipeline and exploration and production operations. We utilized this operating cash flow and cash from our discontinued operations to fund maintenance and growth projects in our pipeline and exploration and production operations and to reduce our debt obligations (see Item 1, Financial Statements, Note 6). The contribution of cash generated from our discontinued operations reflected above consists of the following for the nine months ended September 30, 2007:

	(In billions)
Proceeds from sale of ANR and related assets	$ 3.7
Payments to retire ANR debt obligations	(0.3)
Contribution from discontinued operations	$ 3.4

Table of Contents

Our cash capital expenditures (including acquisitions) for the nine months ended September 30, 2007, and our expected capital expenditures for the remainder of 2007 to grow and maintain our businesses are as follows (in billions):

	Nine Months Ended September 30, 2007	2007 Remaining	Total
Maintenance			
Pipelines	$ 0.3	$ 0.1	$ 0.4
Exploration and Production	1.1	0.1	1.2
Growth			
Pipelines	0.4	0.3	0.7
Exploration and Production	1.2	0.2	1.4
	$ 3.0	$ 0.7	$ 3.7

The substantial repayment of debt obligations during 2007 has been a milestone in improving our credit profile and credit ratings. In March 2007, Moody s Investor Services upgraded our pipeline subsidiaries senior unsecured debt rating to an investment grade rating of Baa3 and upgraded El Paso s senior unsecured debt rating to Ba3 while maintaining a positive outlook. Additionally, in March 2007, (i) Standard and Poor s upgraded our pipeline subsidiaries senior unsecured debt rating to BB and upgraded El Paso s senior unsecured debt rating to BB- maintaining a positive outlook and (ii) Fitch Ratings initiated coverage on El Paso assigning a rating of BB+ on our senior unsecured debt and an investment grade rating of BBB- to our pipeline subsidiaries senior unsecured debt. In addition, the refinancing of approximately $2.0 billion of the debt of our subsidiaries EPEP, SNG and EPNG provides us with a lower cost of borrowing and less restrictive covenants on this debt.

Liquidity/Cash Flow Outlook. For the remainder of 2007, we expect to continue to generate positive operating cash flows. We anticipate using these amounts together with amounts borrowed under credit facilities and proceeds from remaining asset sales for working capital requirements, expected capital expenditures and to repay debt as it matures (approximately $0.6 billion of debt matures through September 30, 2008). Based on financings completed in 2007 and our debt maturity profile, we do not anticipate having to access the debt capital markets until 2008.

Factors That Could Impact Our Future Liquidity. Based on the simplification of our capital structure and our businesses, we have reduced the amount of liquidity needed in the normal course of business. However, our liquidity needs could increase or decrease based on certain factors described below. For a complete discussion of risk factors that could impact our liquidity, see our 2006 Annual Report on Form 10-K.

Price Risk Management Activities and Cash Margining Requirements. Our Exploration and Production and Marketing segments have derivative contracts that provide price protection on a portion of our anticipated natural gas and oil production. During the nine months ended September 30, 2007, we entered into floor and ceiling option contracts (net of terminations) on approximately 86 TBtu, basis swaps on 77 TBtu and fixed price swaps on 28 TBtu, all related to anticipated 2008 natural gas production. The following table shows the contracted volumes and the minimum, maximum and average cash prices that we will receive under our derivative contracts when combined with the sale of the underlying production as of September 30, 2007. These cash prices may differ from the income impacts of our derivative contracts, depending on whether the contracts are designated as hedges for accounting purposes or not. The individual segment discussions provide additional information on the income impacts of our derivative contracts.

Table of Contents

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)			
							Texas Gulf Coast		Onshore-Raton	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas										
2007	22	$ 7.66	36	$ 7.69	14	$16.89	20	$(0.66)	7	$ (1.09)
2008	33	$ 7.65	104	$ 8.00	104	$10.82	51	$(0.33)	26	$ (1.13)
2009	5	$ 3.56	17	$ 6.00	17	$ 8.75				
2010-2012	11	$ 3.81								
Oil										
2007	48	$35.15	239	$55.00	239	$58.75				
2008			930	$55.00	930	$57.03				

(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.

In October 2007, on our anticipated natural gas production, we terminated 6 TBtu of our $7.50 floors for 2007 and entered into (i) 8TBtu of $8.00 fixed price swaps for 2007; (ii) 4 TBtu of $8.00 floors and $10.00 ceilings for 2008; and (iii) 15 TBtu of basis swaps for the onshore Raton region for 2009.

We currently post letters of credit for the required margin on certain of our derivative contracts. Historically, we were required to post cash margin deposits for these amounts. During the first nine months of 2007, approximately $83 million of posted cash margin deposits were returned to us resulting from settlement of the related contracts and changes in commodity prices. For the remainder of 2007, based on current prices, we expect approximately $0.1 billion of the total of $1.0 billion in collateral outstanding at September 30, 2007 to be returned to us, primarily in the form of letters of credit.

Depending on changes in commodity prices, we could be required to post additional margin or may recover margin earlier than anticipated. Based on our derivative positions at September 30, 2007, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements of approximately $14 million which consists of $1 million for transactions that settle in the remainder of 2007, $4 million for transactions that settle in 2008, $3 million for transactions that settle in 2009 and $6 million for transactions that settle in 2010 and thereafter. We have a $250 million unsecured contingent letter of credit facility available to us if the average NYMEX gas price strip for the remaining calendar months through March 2008 reaches $11.75 per MMBtu, which is further described in Item I, Financial Statements, Note 6.

Hurricanes. We continue to repair damages to our pipeline and other facilities caused by Hurricanes Katrina and Rita in 2005. For the remainder of 2007 and 2008, we expect repair costs of approximately $95 million (a substantial portion of which is capital related) and insurance reimbursements of approximately $140 million for cumulative recoverable costs from our insurers. While our capital expenditures and liquidity may vary from period to period, we do not believe our remaining hurricane related expenditures will materially impact our overall liquidity or financial results.

Commodity-Based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. In the tables below, derivatives designated as accounting hedges primarily consist of collars and swaps used to hedge natural gas production. Other commodity-based derivative contracts relate to derivative contracts not designated as accounting hedges, such as options, swaps and other natural gas and power purchase and supply contracts. The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of September 30, 2007:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as accounting hedges						
Assets	$ 93	$ 13	$	$	$	$ 106
Liabilities	(19)	(38)	(26)			(83)
Total derivatives designated as accounting hedges	74	(25)	(26)			23
Other commodity-based derivatives						
Exchange-traded positions[1]						
Liabilities		(12)				(12)
Non-exchange traded positions						
Assets	72	56	54	28	6	216
Liabilities	(257)	(365)	(262)	(177)	(4)	(1,065)
Total other commodity-based derivatives	(185)	(321)	(208)	(149)	2	(861)
Total commodity-based derivatives	$ (111)	$ (346)	$ (234)	$ (149)	$ 2	$ (838)

(1) These positions are traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London

Clearinghouse.

The following is a reconciliation of our commodity-based derivatives for the nine months ended September 30, 2007:

	Derivatives Designated as Accounting Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at January 1, 2007	$ 61	$ (456)	$ (395)
Fair value of contract settlements during the period[1]	(84)	(281)	(365)
Change in fair value of contracts	25	(148)	(123)
Assignment of contracts		18	18
Option premiums paid[2]	21	6	27
Net change in contracts outstanding during the period	(38)	(405)	(443)
Fair value of contracts outstanding at September 30, 2007	$ 23	$ (861)	$ (838)

(1) During 2007, we settled derivative assets of approximately $381 million by applying the related cash margin we held against amounts due to us under those contracts.

(2) Amounts are net of premiums received.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

Production-Related Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These derivative contracts are entered into by both our Exploration and Production and Marketing segments. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks. We have designated certain of these derivatives as accounting hedges. Contracts that are designated as accounting hedges will impact our earnings when the related hedged production sales occur, and, as a result, any gain or loss on these hedging derivatives would be offset by a gain or loss on the sale of the underlying hedged commodity, which is not included in the table. Contracts that are not designated as accounting hedges impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risks of our forecasted sales of natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

		10 Percent Increase		**10 Percent Decrease**	
	Fair Value	**Fair Value**	**(Decrease)**	**Fair Value**	**Increase**
Impact of changes in commodity prices on production-related derivative assets (liabilities)					
September 30, 2007	$ 11	$(111)	$(122)	$138	$127
December 31, 2006	$124	$ (9)	$(133)	$264	$140

Other Commodity-Based Derivatives. In our Marketing segment, we have other derivative contracts that are not used to mitigate the commodity price risk associated with our natural gas and oil production. Many of these contracts, which include forwards, swaps, options and futures, are long-term historical contracts that we either intend to assign to third parties or manage until their expiration. We measure risks from these contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts of adverse market movements over a defined period of time within a specified confidence level and allows us to monitor our risk in comparison to established thresholds. To measure Value-at-Risk, we use what is known as the historical simulation technique. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio s sensitivity to underlying risks. These analyses and our Value-at-Risk simulations do not include commodity exposures related to our production-related derivatives (described above), our Marketing segment s natural gas transportation related contracts that are accounted for under the accrual basis of accounting, or our Exploration and Production segment s sales of natural gas and oil production.

Our maximum expected one-day unfavorable impact on the fair values of our other commodity-based derivatives as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $1 million and $6 million as of September 30, 2007 and December 31, 2006. We may experience changes in our Value-at-Risk in the future if commodity prices are volatile.

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2007, 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, as defined by the Securities Exchange Act of 1934, as amended. 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 SEC reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and 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 a company have been detected. Based on the results of our evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective at a reasonable level of assurance at September 30, 2007.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the third quarter of 2007.

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 2006 Annual Report on Form 10-K filed with the SEC.

Fort Morgan Storage Field. CIG owns and operates an underground natural gas storage field in the vicinity of Fort Morgan, Colorado. In October 2006, the production casing in one of the field s injection and withdrawal wells resulted in the emergence of natural gas from the storage reservoir at the ground surface. CIG has received a proposed Administrative Order by Consent (AOC) from the Colorado Oil and Gas Conservation Commission that contains an initial penalty demand of $638,000. The parties are currently in negotiations regarding the resolution of the AOC and the determination of the fine to be imposed, if any.

Rawlins Plant Notice of Probable Violation. CIG owns and operates the Rawlins Gas Plant and Compressor Station which produces butane, propane, and natural gas liquids. Recently, CIG discovered that emissions from the loading process were emitted into the atmosphere and self-reported the discovery to the Wyoming Department of Environmental Quality (the Department) which issued a Notice of Violation. CIG and the Department have reached a tentative settlement of this matter of $119,000, pending the negotiation of definitive settlement documents.

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.

Table of Contents

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 2006 Annual Report on Form 10-K. There have been no material changes in our risk factors since that report.

With regard to any discussion of a potential pipeline master limited partnership, a registration statement relating to such securities has been filed with the SEC but has not yet become effective. The common units of the MLP may not be sold, nor may offers to buy be accepted, prior to the time the registration statement becomes effective. The information in this quarterly report on Form 10-Q does not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the common units of the MLP in any state or jurisdiction in which such offer, solicitation, or sale would be unlawful prior to registration or qualification under the securities laws of any such state or jurisdiction.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference and lists the exhibits required to be filed by this report by Item 601(b)(10)(iii) of Regulation S-K.

Table of Contents

SIGNATURES

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

	EL PASO CORPORATION
Date: November 6, 2007	/s/ D. Mark Leland
	D. Mark Leland Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 6, 2007	/s/ John R. Sult
	John R. Sult Senior Vice President and Controller (Principal Accounting Officer)

Table of Contents

EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed as a part of this Report.

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.