EL PASO CORP/DE
Form 10-Q
August 08, 2008

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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2008

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Common stock, par value $3 per share. Shares outstanding on August 4, 2008: 701,202,029

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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.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Operating revenues	$ 1,153	$ 1,198	$ 2,422	$ 2,220
Operating expenses				
Cost of products and services	71	60	127	115
Operation and maintenance	282	329	553	630
Depreciation, depletion and amortization	298	286	611	557
Taxes, other than income taxes	81	72	160	132
	732	747	1,451	1,434
Operating income	421	451	971	786
Earnings from unconsolidated affiliates	52	44	89	81
Loss on debt extinguishment		(86)		(287)
Other income, net	33	60	55	106
Minority interest	(7)	1	(16)	
Interest and debt expense	(221)	(231)	(454)	(514)
Income before income taxes from continuing operations	278	239	645	172
Income taxes	87	70	235	51
Income from continuing operations	191	169	410	121
Discontinued operations, net of income taxes		(3)		674
Net income	191	166	410	795
Preferred stock dividends		10	19	19
Net income available to common stockholders	$ 191	$ 156	$ 391	$ 776
Basic earnings per common share				
Income from continuing operations	$ 0.27	$ 0.23	$ 0.56	$ 0.15
Discontinued operations, net of income taxes				0.97
Net income per common share	$ 0.27	$ 0.23	$ 0.56	$ 1.12
Diluted earnings per common share				

Income from continuing operations	$ 0.25	$ 0.22	$ 0.54	$ 0.15
Discontinued operations, net of income taxes				0.96
Net income per common share	$ 0.25	$ 0.22	$ 0.54	$ 1.11
Dividends declared per common share	$	$ 0.04	$ 0.08	$ 0.08

See accompanying notes.

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

	June 30, 2008	December 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 274	$ 285
Accounts and notes receivable		
Customers, net of allowance of $11 in 2008 and $17 in 2007	829	468
Affiliates	145	196
Other	175	201
Inventory	143	131
Assets from price risk management activities	182	113
Deferred income taxes	458	191
Other	168	127
Total current assets	2,374	1,712
Property, plant and equipment, at cost		
Pipelines	17,191	16,750
Natural gas and oil properties, at full cost	19,011	19,048
Other	306	530
	36,508	36,328
Less accumulated depreciation, depletion and amortization	17,340	16,974
Total property, plant and equipment, net	19,168	19,354
Other assets		
Investments in unconsolidated affiliates	1,863	1,614
Assets from price risk management activities	207	302
Other	1,614	1,597
	3,684	3,513
Total assets	$ 25,226	$ 24,579

See accompanying notes.

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

	June 30, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 639	$ 460
Affiliates	9	5
Other	477	502
Current maturities of long-term financing obligations	1,236	331
Liabilities from price risk management activities	785	267
Accrued interest	182	195
Other	739	653
Total current liabilities	4,067	2,413
Long-term financing obligations, less current maturities	11,223	12,483
Other		
Liabilities from price risk management activities	1,064	931
Deferred income taxes	1,437	1,157
Other	1,566	1,750
	4,067	3,838
Commitments and contingencies (Note 8)		
Minority interest	545	565
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 711,992,983 shares in 2008 and 709,192,605 shares in 2007	2,136	2,128
Additional paid-in capital	4,679	4,699
Accumulated deficit	(1,420)	(1,834)
Accumulated other comprehensive loss	(617)	(272)
Treasury stock (at cost); 9,378,210 shares in 2008 and 8,656,095 shares in 2007	(204)	(191)
Total stockholders equity	5,324	5,280
Total liabilities and stockholders equity	$ 25,226	$ 24,579

See accompanying notes.

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Cash flows from operating activities		
Net income	$ 410	$ 795
Less income from discontinued operations, net of income taxes		674
Income from continuing operations	410	121
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	611	557
Deferred income tax expense	236	42
Earnings from unconsolidated affiliates, adjusted for cash distributions	(8)	40
Loss on debt extinguishment		287
Other non-cash income items	36	13
Asset and liability changes	33	(178)
Cash provided by continuing activities	1,318	882
Cash used in discontinued activities		(17)
Net cash provided by operating activities	1,318	865
Cash flows from investing activities		
Capital expenditures	(1,175)	(1,130)
Cash paid for acquisitions	(336)	(270)
Net proceeds from the sale of assets and investments	659	80
Other	43	20
Cash used in continuing activities	(809)	(1,300)
Cash provided by discontinued activities		3,660
Net cash provided by (used in) investing activities	(809)	2,360
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	2,670	3,666
Payments to retire long-term debt and other financing obligations	(3,071)	(6,765)
Dividends paid	(75)	(75)
Payments to minority interest holders	(12)	
Contributions from discontinued operations		3,360
Other	(32)	4
Cash provided by (used in) continuing activities	(520)	190

Cash used in discontinued activities		(3,643)
Net cash used in financing activities	(520)	(3,453)
Change in cash and cash equivalents	(11)	(228)
Cash and cash equivalents		
Beginning of period	285	537
End of period	$ 274	$ 309

See accompanying notes.

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net income	$ 191	$ 166	$ 410	$ 795
Pension and postretirement obligations:				
Unrealized actuarial losses arising during period (net of income taxes of $1 in 2008)			(2)	
Reclassification adjustments (net of income taxes of $3 and $5 in 2008 and $4 and $7 in 2007)	5	7	10	13
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $152 and $222 in 2008 and $28 and $19 in 2007)	(272)	50	(395)	(33)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $21 and $22 in 2008 and $9 and $24 in 2007)	37	(15)	39	(40)
Investments available for sale:				
Unrealized gains on investments available for sale arising during period (net of income taxes of $2 in 2007)				3
Realized gains on investments available for sale arising during period (net of income taxes of $8 in 2007)		(15)		(15)
Other comprehensive income (loss)	(230)	27	(348)	(72)
Comprehensive income (loss)	$ (39)	$ 193	$ 62	$ 723

See accompanying notes.

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). 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 2007 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2008, and for the quarters and six months ended June 30, 2008 and 2007, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2007, from the audited balance sheet filed in our 2007 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 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 of our significant accounting policies and accounting pronouncements issued but not yet adopted as discussed in our 2007 Annual Report on Form 10-K.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, for our financial assets and liabilities. We elected to defer the adoption of SFAS No. 157 for our non-financial assets and liabilities until January 1, 2009. The impact of adopting SFAS No. 157 was both a pre-tax increase to operating revenues of $6 million and to other comprehensive income of $4 million, and a reduction of our liabilities of $10 million, which represented the impact of the consideration of our credit standing in determining the value of our price risk management liabilities.

Measurement Date of Postretirement Benefits. Effective January 1, 2008, we adopted the measurement date 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 changed the measurement date of our postretirement benefit plans from September 30 to December 31. We recorded a $5 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated deficit and a $3 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated other comprehensive loss upon the adoption of the measurement date provisions of this standard to reflect an additional three months of net periodic benefit cost based on our September 30, 2007 measurement.

Derivative Instruments. In March 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, which requires expanded disclosures about derivative instruments. This standard requires companies to disclose their purpose for using derivative instruments, how those derivatives are accounted for under SFAS No. 133, and where the impacts of those derivatives are reflected in the financial statements. The provisions of this standard are effective for fiscal years beginning after November 15, 2008, and we are currently evaluating the impact that the adoption of this standard will have on our financial statement disclosures.

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2. Acquisitions and Divestitures

Acquisitions

Gulf LNG. In February 2008, we paid $295 million to complete the acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, an LNG terminal which is currently under construction in Pascagoula, Mississippi. The terminal is expected to be placed in service in late 2011 at an estimated total cost of $1.1 billion. In addition, we have a commitment to loan Gulf LNG up to $150 million under which we advanced $7 million as of June 30, 2008. Our partner in this project has a commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

Exploration and Production properties. In June 2008, we acquired interests in onshore domestic natural gas and oil properties for approximately $43 million. In January 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas for approximately $254 million.

Divestitures

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as 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 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 from continuing financing activities.

Continuing operations asset sales. During the six months ended June 30, 2008, we sold natural gas and oil properties primarily in our Gulf of Mexico and Texas Gulf Coast regions for net cash proceeds of approximately $640 million. We also sold two power investments located in Central America and Asia. During the six months ended June 30, 2007, we received approximately $80 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).

Discontinued Operations. In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for approximately $3.7 billion. During the first quarter of 2007, we 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 sale were net deferred tax liabilities assumed by the purchaser. Below is summarized income statement information regarding our discontinued operations:

	ANR and Related Operations (In millions)
Six Months Ended June 30, 2007	
Revenues	$ 101
Costs and expenses	(43)
Other expense	(7)
Interest and debt expense	(10)
Income taxes	(15)
Income from operations	26
Gain on sale, net of income taxes of $354 million[(1)]	648
Net income from discontinued operations	$ 674

(1) During the second quarter

of 2007, we recognized a $3 million loss, net of income taxes of $2 million, from discontinued operations related to a reduction of the gain on the sale of ANR primarily to reflect post-closing adjustments related to the sale.

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3. Income Taxes

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions, except for rates)			
Income taxes	$ 87	$ 70	$ 235	$ 51
Effective tax rate	31%	29%	36%	30%

We compute interim period income taxes by applying an anticipated annual effective tax rate to our year-to-date income or loss, except for significant unusual or infrequently occurring items. Significant tax items are recorded in the period that the item occurs.

In the second quarter of 2008, our effective tax rate was primarily impacted by the tax impact of the settlement of legacy litigation matters. For the six months ended June 30, 2008, this impact was largely offset by the tax impact of adjusting our postretirement benefit obligations. Our 2007 overall effective tax rate on continuing operations was lower than the statutory rate of 35 percent primarily due to tax benefits associated with tax law changes and dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends. These reductions were partially offset by state income taxes (net of federal income tax effects) and the reversal of deferred tax assets on certain foreign investments.

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. In June 2008, the Internal Revenue Service s examination of El Paso s U.S. income tax returns for 2003 and 2004 was settled at the appellate level with approval by the Joint Committee on Taxation. The settlement of issues raised in this examination did not materially impact 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, although we are unable to estimate the range of potential impacts these matters could have on our financial statements.

As of January 1, 2008 and June 30, 2008, we had unrecognized tax benefits of $157 million and $125 million. The reduction in these amounts was primarily associated with the settlement of the 2003 and 2004 Internal Revenue Service audits and was recorded as an adjustment to additional paid in capital. Approximately $132 million as of January 1, 2008 and $121 million as of June 30, 2008 (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.

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4. Earnings Per Share

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

	2008		2007	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Quarters Ended June 30				
Income from continuing operations	$ 191	$ 191	$ 169	$ 169
Convertible preferred stock dividends[(1)]			(10)	
Income from continuing operations available to common stockholders	191	191	159	169
Discontinued operations, net of income taxes			(3)	(3)
Net income available to common stockholders	$ 191	$ 191	$ 156	$ 166
Weighted average common shares outstanding	698	698	696	696
Effect of dilutive securities:				
Options and restricted stock		5		4
Convertible preferred stock		58		57
Weighted average common shares outstanding and dilutive securities	698	761	696	757
Earnings per common share:				
Income from continuing operations	$ 0.27	$ 0.25	$ 0.23	$ 0.22
Discontinued operations, net of income taxes				
Net income	$ 0.27	$ 0.25	$ 0.23	$ 0.22

	2008		2007	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Six Months Ended June 30				
Income from continuing operations	$ 410	$ 410	$ 121	$ 121
Convertible preferred stock dividends	(19)		(19)	(19)
Income from continuing operations available to common stockholders	391	410	102	102
Discontinued operations, net of income taxes			674	674
Net income available to common stockholders	$ 391	$ 410	$ 776	$ 776
Weighted average common shares outstanding	698	698	695	695
Effect of dilutive securities:				

Options and restricted stock		4		4
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	698	760	695	699
Earnings per common share:				
Income from continuing operations	$ 0.56	$ 0.54	$ 0.15	$ 0.15
Discontinued operations, net of income taxes			0.97	0.96
Net income	$ 0.56	$ 0.54	$ 1.12	$ 1.11

(1) Dividends were declared in February and March 2008. No dividends were declared during the quarter ended June 30, 2008.

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. For the quarter and six months ended June 30, 2008 and 2007, certain of our employee stock options and our trust preferred securities were antidilutive. Also, our convertible preferred stock for the six months ended June 30, 2007 was antildilutive. For a further discussion of our potentially dilutive securities, see our 2007 Annual Report on Form 10-K.

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5. Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS No. 157, *Fair Value Measurements*, and SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, for our financial assets and liabilities. SFAS No. 157 expands the disclosure requirements for financial instruments and other derivatives recorded at fair value, and also requires that a company s own credit risk be considered in determining the fair value of those instruments. The adoption of SFAS No. 157 resulted in a $6 million increase in operating revenues, a $4 million pre-tax increase in other comprehensive income, and a $10 million reduction of our liabilities to reflect the consideration of our credit risk on our liabilities that are recorded at fair value. SFAS No. 159 provided us the option to record most financial assets and liabilities at fair value on an instrument-by-instrument basis with changes in their fair value reported through the income statement. The adoption of SFAS No. 159 had no impact on our financial statements as we elected not to apply fair value accounting at adoption for our applicable financial assets and liabilities.

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

Level 1 instruments fair values are based on quoted prices in actively traded markets. Included in this level are our marketable securities invested in non-qualified compensation plans whose fair value is determined using quoted prices of these instruments.

Level 2 instruments fair values are based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets). Included in this level are our production-related natural gas and oil derivatives and certain of our other natural gas derivatives (such as natural gas supply arrangements) whose fair values are based on commodity pricing data obtained from an independent pricing source.

Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but their fair value also reflects adjustments for being in less liquid markets or having longer contractual terms. For these instruments, we use available pricing data adjusted for liquidity and/or contractual terms to develop an estimate of forward price curves. The curves are then used to estimate the value of settlements in future periods based on contractual settlement quantities and dates. Our valuation of these instruments considers specific contractual terms, statistical and simulation analysis, present value concepts and other internal assumptions related to (i) contract maturities that extend beyond the periods in which quoted market prices are available; (ii) the uniqueness of the contract terms and (iii) the lack of viable market participants. Since a significant portion of the fair value of our power-related derivatives, foreign currency swaps and certain of our remaining natural gas derivatives with longer terms or in less liquid markets than similar Level 2 derivatives, rely on the techniques discussed above, we classify these instruments as Level 3 instruments.

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Listed below are the fair values of our financial instruments classified in each level at June 30, 2008 (in millions):

	Level 1	Level 2	Level 3	Total
Assets				
Marketable securities invested in non-qualified compensation plans	$ 20	$	$	$ 20
Production-related natural gas and oil derivatives		3		3
Other natural gas derivatives		44	46	90
Power-related derivatives			164	164
Foreign currency swaps			132	132
Total assets	$ 20	$ 47	$ 342	$ 409

	Level 1	Level 2	Level 3	Total
Liabilities				
Production-related natural gas and oil derivatives	$	$ (714)	$	$ (714)
Other natural gas derivatives		(183)	(209)	(392)
Power-related derivatives			(736)	(736)
Interest rate swaps		(7)		(7)
Other			(67)	(67)
Total liabilities		(904)	(1,012)	(1,916)
Total	$ 20	$ (857)	$ (670)	$ (1,507)

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter and six months ended June 30, 2008 (in millions):

Quarter Ended June 30, 2008

	Balance at Beginning of Period	Change in fair value reflected in operating revenues[(1)]	Change in fair value reflected in operating expenses[(2)]	Change in fair value reflected in long-term financing obligations[(3)]	Settlements, Net	Balance at End of Period
Assets	$ 332	$ 58	$	$ (39)	$ (9)	$ 342
Liabilities	(913)	(154)	13		42	(1,012)
Total	$ (581)	$ (96)	$ 13	$ (39)	$ 33	$ (670)

Six Months Ended June 30, 2008

Assets	$ 250	$ 90	$	$ 20	$ (18)	$ 342
Liabilities	(839)	(224)	(31)		82	(1,012)

Total	$	(589)	$	(134)	$	(31)	$	20	$	64	$	(670)

(1) Includes approximately $92 million and $133 million of net losses that had not been realized through settlements for the quarter and six months ended June 30, 2008.

(2) Includes approximately $12 million of net gains and $26 million of net losses that had not been realized through settlements for the quarter and six months ended June 30, 2008.

(3) Includes approximately $39 million of net losses and $20 million of net gains that had not been realized through settlements for the quarter and six months ended June 30, 2008.

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6. 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 and 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 accounting hedges of our interest rate and foreign currency risk on long-term debt.

	June 30, 2008	December 31, 2007
	(In millions)	
Net assets (liabilities):		
Derivatives designated as accounting hedges	$ (581)	$ (23)
Other commodity-based derivative contracts	(1,004)	(869)
Total commodity-based derivatives	(1,585)	(892)
Interest rate and foreign currency derivatives	125	109
Net liabilities from price risk management activities[1]	$ (1,460)	$ (783)

(1) Included in both current and non-current assets and liabilities on the balance sheet.

7. Long-Term Financing Obligations and Other Credit Facilities

	June 30, 2008	December 31, 2007
	(In millions)	
Current maturities of long-term financing obligations	$ 1,236	$ 331
Long-term financing obligations	11,223	12,483
Total	$ 12,459	$ 12,814

Long Term Financing Obligations. During the second quarter of 2008, we repurchased approximately $289 million of our subsidiary debt obligations and issued $600 million of unsecured senior notes that mature in June 2018. Interest accrues on the issued notes at a rate of 7.25% per year and is payable semiannually. We applied the net proceeds from these notes to reduce outstanding borrowings under our credit facilities.

Credit Facilities. As of June 30, 2008, we had available capacity under various credit agreements of approximately $1.5 billion. During the second quarter of 2008, we made net repayments of $275 million under our $1.5 billion revolving credit facility bringing the debt outstanding to zero. As of June 30, 2008, we had approximately $0.3 billion of letters of credit issued under this facility. Additionally, as of June 30, 2008, (i) substantially all of the $1.0 billion of capacity under our various other unsecured revolving credit facilities was used to issue letters of credit and

(ii) approximately $0.7 billion was outstanding under our El Paso Exploration & Production Company (EPEP) $1.0 billion revolving credit facility.

During 2008, El Paso Pipeline Partners, L.P. (EPB), our master limited partnership (MLP), had net additional borrowings of $40 million under its credit facility. As of June 30, 2008, the total amount outstanding under the facility was $495 million. The EPB borrowings are not recourse to El Paso and the facility is solely available for use by EPB and its subsidiaries.

Letters of Credit. We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of June 30, 2008, we had outstanding letters of credit of approximately $1.3 billion of which approximately $1.0 billion secure our recorded obligations related to price risk management activities.

8. Commitments and Contingencies

Legal Proceedings

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

Retiree Medical Benefits Matter. In 2002, a lawsuit entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation* was filed in a federal court in Detroit, Michigan. The lawsuit was filed on behalf of a group of retirees of Case Corporation (Case) that alleged they are entitled to retiree medical benefits under a medical benefits plan that we serve as plan administrator pursuant to a merger agreement with Tenneco Inc. Although we had asserted that our obligations under the plan were subject to a cap pursuant to an agreement with the union for Case employees, in the first quarter of 2008, the trial court granted summary judgment and ruled that the benefits were vested and not subject to the cap. As a result, we were obligated to pay the amounts above the cap and we adjusted our existing indemnification accrual using current actuarial assumptions and reclassified our liability as a postretirement benefit obligation. See Note 9 for a discussion of the impact of this matter. We intend to pursue appellate options following the determination by the trial court of any damages incurred by the plaintiffs during the period when premium payments above the cap were paid by the retirees. We believe our accruals established for this matter are adequate.

Price Reporting Litigation. Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price information to industry trade publications that published gas indices. The first 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. The second set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include Farmland Industries v. Oneok Inc., et al. (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., et al. v. AEP Energy Services Inc., et al. (filed in federal court for the Eastern District of California in September 2005); Learjet, Inc., et al. v. Oneok Inc., et al. (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 Missouri Public Service case was transferred to the MDL, but remanded back to state court, where a motion to dismiss has been filed. The remaining cases have all been transferred to the MDL proceeding. The Breckenridge Case has been dismissed, but a motion for reconsideration was filed. Motions for summary judgment in Learjet and Farmland were denied, but a motion for reconsideration has been filed. Discovery is proceeding in the MDL cases. 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 and 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 second 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 claims 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 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 81 such lawsuits. 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. 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 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. We have reached an agreement with the plaintiffs to settle approximately 59 of the lawsuits. We have also reached an agreement with our insurers, whereby our insurers would fund substantially all of the consideration to be provided by our subsidiaries under the terms of the settlement with the plaintiffs. The settlement is subject to the approval of several courts, one of which has approved it. The settlement will become effective upon the approval of the remaining courts and the exhaustion of all appellate rights. Approximately 22 of the remaining lawsuits are not covered by the terms of this settlement. While the damages claimed in these remaining actions are substantial, there remains significant legal uncertainty regarding the validity of the causes of action asserted and the availability of the relief sought by the plaintiffs. We have tendered these remaining cases to our insurers. Our costs and legal exposure related to these remaining 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 cooperated with the SEC in its investigation. On July 10, 2008, the SEC approved a settlement entered into by El Paso Corporation and two of its subsidiaries, El Paso Exploration and Production and El Paso CGP (which was formerly known as The Coastal Corporation), that fully resolves the previously disclosed SEC s investigation of our oil and gas reserve estimates for periods prior to 2004. Pursuant to the terms of the settlement, no monetary fine or penalty has been imposed upon the companies and, without admitting or denying any wrongdoing, the companies consented to the entry of a cease and desist order with respect to various provisions of the Securities Act of 1933, the Securities Exchange Act of 1934 and related SEC rules.

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 June 30, 2008, we had approximately $120 million accrued, which has not been reduced by $33 million of related insurance receivables, for outstanding legal and governmental proceedings.

Rates and Regulatory Matters

Notice of Inquiry on Pipeline Fuel Retention Policies. In September 2007, the Federal Energy Regulatory Commission (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 the recovery of a fixed percentage as a non-negotiable fee-in-kind retained from the volumes tendered for shipment by each shipper. 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. At this time, we do not know what impact, if any, this proceeding may ultimately have on our pipeline subsidiaries.

EPNG Rate Case. In June 2008, El Paso Natural Gas Company (EPNG) filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposes an increase in EPNG s base tariff rates which would increase revenue by $83 million annually over current tariff rates. In August 2008, the FERC issued an order accepting and suspending the effective date of the proposed rates to January 1, 2009, subject to refund and the outcome of a hearing and technical conference.

Notice of Proposed Rulemaking. On October 3, 2007, the Minerals Management Service (MMS) issued a Notice of Proposed Rulemaking for Oil and Gas and Sulphur Operations in the Outer Continental Shelf (OCS) Pipelines and Pipeline Rights-of-Way. If adopted, the proposed rules would substantially revise MMS OCS pipeline and rights-of-way regulations. The proposed rules would have the effect of: (1) increasing the financial obligations of entities, like us, which have pipelines and pipeline rights-of-way in the OCS; (2) increasing the regulatory requirements imposed on the operation and maintenance of existing pipelines in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS.

Greenhouse Gas Emissions. In July, 2008, the U.S. Environmental Protection Agency (EPA) requested public comments on the potential regulation of greenhouse gases (GHGs) under the Clean Air Act. Some of the regulatory alternatives identified by the EPA in its request for comments, if eventually promulgated as final rules, would likely impact our operations and financial results. It is uncertain whether the EPA will proceed with adopting final rules or whether the regulation of the GHGs will be addressed in federal and state legislation. Since it is uncertain what, if any, regulatory or legislative alternatives may be adopted, it is not possible at this time to determine whether and how such laws or regulations could impact our operations and financial results and whether those impacts will be material to our financial statements.

Other Matter

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. In June 2008, EPNG reached an agreement in principle on the fundamental economic terms of a tribal consent extension through October 2025. Based on the preliminary agreement, EPNG made payments to the Navajo Nation covering the period from January 2007 through October 2008. Negotiations on the remaining terms and conditions are continuing. We have filed with the FERC for recovery of these amounts in our recent rate case, but are uncertain as to whether such recovery will be allowed.

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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 June 30, 2008, we had accrued approximately $244 million for environmental matters, which has not been reduced by $24 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $236 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $8 million for related environmental legal costs. Of the $244 million accrual, $20 million was reserved for facilities we currently operate and $224 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $244 million to approximately $450 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 ($14 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($230 million to $436 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:

	June 30, 2008	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 20	$ 26
Non-operating	200	376
Superfund	24	48
Total	$ 244	$ 450

Below is a reconciliation of our accrued liability from January 1, 2008 to June 30, 2008 (in millions):

Balance as of January 1, 2008	$ 260
Additions/adjustments for remediation activities	4
Payments for remediation activities	(20)
Balance as of June 30, 2008	$ 244

For the remainder of 2008, we estimate that our total remediation expenditures will be approximately $41 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $13 million in the aggregate for the years 2008 through 2012. These expenditures primarily relate to compliance with clean air regulations.

CERCLA Matters. As part of our environmental remediation projects, 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 39 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (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. 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 matters 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 Other Contractual Commitments

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. 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, and environmental matters.

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 $834 million, which primarily relates to indemnification arrangements associated with the sale of ANR, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 7. As of June 30, 2008, we have recorded obligations of $73 million related to our indemnification arrangements. This liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification. 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 due to the uncertainty of these exposures.

Other Purchase Obligations. We have entered into contracts to purchase approximately $1.0 billion of pipe associated with the Ruby Pipeline project and TGP s Line 300 project which are anticipated to be placed in service between 2010 and 2011. Our estimated annual obligations under these agreements are approximately $0.3 billion for the remainder of 2008, $0.6 billion in 2009 and $0.1 billion in 2010.

9. Retirement Benefits

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

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007	2008	2007	2008	2007
	(In millions)							
Service cost	$ 3	$ 4	$	$	$ 7	$ 9	$	$
Interest cost	30	30	10	7	60	60	17	13
Expected return on plan assets	(46)	(46)	(4)	(4)	(93)	(91)	(8)	(8)
Amortization of net actuarial loss (gain)	6	11	(1)		12	21	(2)	
Amortization of prior service cost[(1)]			(1)	(1)	(1)	(1)	(1)	(1)
Net benefit cost (income)	$ (7)	$ (1)	$ 4	$ 2	$ (15)	$ (2)	$ 6	$ 4

(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.

Other Matters. In various court rulings prior to March 2008, we were required to indemnify Case Corporation for certain benefits paid to a closed group of Case retirees as further discussed in Note 8. In conjunction with those rulings, we recorded a liability for estimated amounts due under the indemnification using actuarial methods similar to those used in estimating our postretirement benefit plan obligations. This liability, however, was not included in our postretirement benefit obligations or disclosures.

In March 2008, we received a summary judgment from the trial court on this matter that we effectively became the primary party that is obligated to pay for these benefit payments. As a result of the judgment, we adjusted our obligation using current actuarial assumptions, recording a $65 million reduction to current and non-current other liabilities and to operation and maintenance expense. We also reclassified this obligation from an indemnification liability to a postretirement benefit obligation, which increased our overall postretirement benefit obligations by

$280 million.

Due to the addition of the Case retirees described above, we now expect payments under our postretirement benefit plans, net of participant contributions and Medicare subsidies, to be approximately $62 million each year through 2012 and $287 million in total for the five year period from 2013 to 2017.

For the remainder of 2008, we expect to contribute an additional $33 million to our other postretirement benefit plans.

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10. Stockholders Equity

The table below shows the amount of dividends paid and declared in 2008 (dollars in millions).

	Common Stock ($0.04/Share)	Convertible Preferred Stock (4.99%/Year)
Amount paid through June 30, 2008	$ 56	$ 19
Amount paid in July 2008	$ 28	$ 9
Dividends declared subsequent to June 30, 2008		
Date of declaration	July 25, 2008	July 25, 2008
Payable to shareholders on record	September 5, 2008	September 15, 2008
Date payable	October 1, 2008	October 1, 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 2008, 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. On May 15, 2008, our Board of Directors declared a dividend of $0.05 per share for our common shareholders. The dividend will be payable on October 1, 2008 to holders of record on September 5, 2008.

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.

11. Business Segment Information

As of June 30, 2008, our business consists of two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. 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 and other various 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 June 30, 2008, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in three interstate transmission systems. We also own or have interests in two underground natural gas storage facilities, an LNG terminalling facility, and an LNG terminalling facility which is under construction.

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

Marketing. Markets and manages the price risks associated with our natural gas and oil production as well as our remaining legacy trading portfolio.

Power. Manages the risks associated with our remaining international power investments located primarily in South America and Asia. We continue to pursue the sale of these assets.

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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 and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the 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 discontinued operations, (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 June 30:

	Quarters Ended June 30,		**Six Months Ended June 30,**	
	2008	**2007**	**2008**	**2007**
	(In millions)			
Segment EBIT	$ 458	$ 574	$ 1,019	$ 1,000
Corporate and other	41	(104)	80	(314)
Interest and debt expense	(221)	(231)	(454)	(514)
Income taxes	(87)	(70)	(235)	(51)
Income from continuing operations	$ 191	$ 169	$ 410	$ 121

The following table reflects our segment results for the periods ended June 30:

	Segments					
	Pipelines	**Exploration and Production**	**Marketing**	**Power**	**Corporate and Other[1]**	**Total**
	(In millions)					
Quarters Ended June 30, 2008						
Revenue from external customers	$632	$ 198[2]	$ 322	$	$ 1	$1,153
Intersegment revenue	14	457[2]	(468)		(3)	
Operation and maintenance	205	105	8	4	(40)	282
Depreciation, depletion and amortization	99	197			2	298
Earnings from unconsolidated affiliates	25	16		11		52
EBIT	295	304	(153)	12	41	499
2007						
Revenue from external customers	$600	$ 268[2]	$ 301	$	$ 29	$1,198
Intersegment revenue	14	307[2]	(317)		(4)	
Operation and maintenance	181	110	3	7	28	329
	91	189	1		5	286

Depreciation, depletion and amortization						
Earnings (losses) from unconsolidated affiliates	29	3		13	(1)	44
EBIT	318	235	5	16	(104)[3]	470

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. During the quarters ended June 30, 2008 and 2007, we recorded an intersegment revenue elimination of $5 million and $4 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our price risk management activities associated with our natural gas and oil

production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Debt and treasury management activities, which are part of Corporate and Other, included debt extinguishment costs of $86 million for the quarter ended June 30, 2007 primarily related to refinancing of EPEP s $1.2 billion notes.

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	Segments					
		Exploration and			Corporate and	
	Pipelines	Production	Marketing	Power	Other[1]	Total
			(In millions)			
Six Months Ended June 30, 2008						
Revenue from external customers	$1,339	$ 328(2)	$ 744	$	$ 11	$2,422
Intersegment revenue	27	930(2)	(947)		(10)	
Operation and maintenance	400	213	10	9	(79)	553
Depreciation, depletion and amortization	198	409			4	611
Earnings from unconsolidated affiliates	46	26		16	1	89
EBIT	676	546	(213)	10	80	1,099
2007						
Revenue from external customers	$1,231	$ 488(2)	$ 460	$	$ 41	$2,220
Intersegment revenue	27	592(2)	(611)		(8)	
Operation and maintenance	342	220	3	11	54	630
Depreciation, depletion and amortization	185	359	2		11	557
Earnings from unconsolidated affiliates	55	2		24		81
EBIT	682	414	(130)	34	(314)[3]	686

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

June 30, 2008 and 2007, we recorded an intersegment revenue elimination of $10 million and $9 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our price risk management activities associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

(3) Debt and treasury management activities, which are part of Corporate and Other, included debt extinguishment costs of $287 million for the six months ended June 30,

2007, $86 million of which is related to refinancing of EPEP s $1.2 billion notes.

Total assets by segment are presented below:

	June 30, 2008	December 31, 2007
	(In millions)	
Pipelines	$ 14,537	$ 13,939
Exploration and Production	7,663	8,029
Marketing	675	537
Power	498	531
Total segment assets	23,373	23,036
Corporate and Other	1,853	1,543
Total consolidated assets	$ 25,226	$ 24,579

12. 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.

	Investment		Earnings (Losses) from Unconsolidated Affiliates			
			Quarters Ended		Six Months Ended	
	June 30,	December 31,	June 30,		June 30,	
Net Investment and Earnings (Losses)	2008	2007	2008	2007	2008	2007
	(In millions)		(In millions)			
Four Star [1]	$ 688	$ 698	$ 16	$ 3	$ 26	$ 2
Citrus	568	576	19	22	32	44
Gulf LNG[2]	295					
Bolivia to Brazil Pipeline	110	105	3	2	6	5
Gasoductos de Chihuahua	159	146	6	6	13	10
Manaus/Rio Negro[3]		56		5		9
Porto Velho[4]	(62)	(60)		5		7
Asian and Central American Investments[4][5]	17	26	6	(1)	6	(1)
Argentina to Chile Pipeline	24	21	2	2	3	3
Other	64	46			3	2
Total	$ 1,863	$ 1,614	$ 52	$ 44	$ 89	$ 81

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $13 million for the quarters ended June 30, 2008 and 2007 and $27 million for the six months ended June 30, 2008 and 2007. For a further discussion, see

our 2007 Annual Report on Form 10-K.

(2) In February 2008, we acquired a 50 percent interest in Gulf LNG. See Note 2.

(3) We transferred ownership of these plants to the power purchaser in January 2008. Accordingly, we eliminated our equity investments in these entities and retained current assets of $80 million and current liabilities of $24 million after the transfer. For a further discussion, see *Matters that Could Impact our Investments* below.

(4) As of June 30, 2008 and December 31, 2007, we had outstanding advances and receivables of $298 million and $350 million related to our foreign investments of

which $292 million and $335 million related to our investment in Porto Velho.

(5) In the second quarter of 2008, we sold our interests in our Khulna and Tipitapa power investments and recognized a pre-tax gain of $6 million.

Summarized Financial Information	Quarters Ended June 30, 2008	Quarters Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In millions)			
Operating results data:				
Operating revenues	$194	$227	$380	$416
Operating expenses	84	132	177	243
Income from continuing operations	66	62	122	113
Net income[1]	66	62	122	113

(1) Includes net income of less than $1 million and $4 million for the quarters ended June 30, 2008 and 2007, and $1 million and $9 million for the six months ended June 30, 2008 and 2007, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

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We received distributions and dividends from our unconsolidated affiliates of $21 million and $64 million for the quarters ended June 30, 2008 and 2007 and $81 million and $138 million for the six months ended June 30, 2008 and 2007. Included in these amounts for the quarter and six months ended June 30, 2007 are returns of capital of $17 million. Our revenues and charges with unconsolidated affiliates were not material during the quarter and six months ended June 30, 2008. For the quarter and six months ended June 30, 2007, we recorded $12 million and $24 million in interest income primarily related to our note receivable with Porto Velho.

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 that totaled $230 million as of June 30, 2008. The Porto Velho facility generates power committed to a state-owned utility under power purchase agreements, the largest of which extends through 2023. In June of 2008, we signed a letter of intent to sell our investment in the project to our partner, subject to the execution of definitive agreements and the resolution of certain claims with the state-owned utility. These claims include those related to alleged excess fuel consumption by the plant during the period of 2003 to 2007 totaling approximately $60 million. We believe that we have valid defenses to these fuel claims. The state-owned utility has made additional net claims of $30 million for retroactive currency indexation adjustments through 2007, which are partially offset by retroactive revenue surcharges for periods through 2007 when the plant used oil for fuel. We are currently in negotiations with the utility to resolve these issues and any adverse developments in our negotiations with our partner or the utility could impact our ability to sell our investment in the project.

If we do not complete the sale of our interests in the project, our remaining investment in the Porto Velho project may be adversely impacted by developments in the Brazilian power market, which continues to evolve and mature. During 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.

We recovered $45 million of our investment during the first half of 2008 and an additional $19 million in July 2008 through payments we received from the project. In conjunction with the negotiations on the sale of our investment, in July 2008, we and our partner extended to November 30, 2008 the date on which we will be required to convert into equity approximately $80 million of the amounts due to us under the note receivable from Porto Velho. In addition, we may be required to convert up to an additional $80 million of the note on November 30, 2008, depending on the level of equity that our partner contributes to the project. These potential equity conversions would occur only if we were unable to complete the sale of our interest to our partner. The conversions would not impact our total investment in the project, however they could increase our percentage ownership in Porto Velho while diluting our partner s ownership in the project.

During the second quarter of 2008, the Brazilian courts upheld a ruling that the statute of limitations had expired related to a $30 million fine assessed against the Porto Velho power project pertaining to filing certain tax forms for the delivery of fuel to the power facility in 2001. The Brazilian tax authorities exhausted their ability to appeal these rulings and, as a result, we believe that this matter has been resolved.

Manaus /Rio Negro. On January 15, 2008, we transferred our ownership in the Manaus and Rio Negro facilities to the plants power purchaser as required by their power purchase agreements. As of June 30, 2008, we have approximately $72 million of Brazilian reais-denominated accounts receivable owed to us under the projects terminated power purchase agreements, which are guaranteed by the purchaser s parent. The purchaser has withheld payment of these receivables in light of their Brazilian reais-denominated claims of approximately $70 million related to plant maintenance the purchaser claims should have been performed at the plants prior to the transfer, inventory levels and other items. We have been in ongoing discussions with the purchaser about their claims, and early in the second quarter of 2008 we began discussions with the parent of the purchaser. Should these discussions fail and the purchaser not agree to payment of our receivables, we will initiate legal action against the purchaser to collect our receivables and defend against their claims, and ultimately we will seek legal action to enforce the parental guarantee related to our receivables. We have reviewed our obligations under the power purchase agreement in relation to the claims and have accrued an obligation for the uncontested claims. We believe the remaining contested claims are without merit. The ultimate resolution of each of these matters is unknown at this time. Adverse developments related to either our ability to collect amounts due to us or related to the dispute could require us to record additional losses in the future.

Asian power investments. As of June 30, 2008, we had a total investment (including advances to the projects) and guarantees related to our one remaining power plant investment in Asia of approximately $26 million. Any changes in political and economic conditions could negatively impact the amount we ultimately recover in the future on this investment.

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of June 30, 2008, 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. In June 2008, the Bolivian government took control of the majority owner of the Bolivian portion of the pipeline, but has taken no action with regard to our two percent interest in this portion of the pipeline. We continue to monitor and evaluate the potential commercial impact that these political 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 June 30, 2008, our total investment in this pipeline project was approximately $24 million. The government of Argentina has issued decrees significantly increasing export taxes on natural gas transported on the Argentina-to-Chile pipeline. We continue to monitor and evaluate, together with our partners, the potential impact that these events in Argentina could have on our investment. In 2008, we executed a letter of intent to sell our interest to one of our partners, subject to the execution of definitive agreements and completion of due diligence by the buyer.

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2007 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 and Operational Update. During the first six months of 2008, our pipeline operations continued to provide a strong base of earnings and cash flow. Additionally, we continue to make progress on and grow our backlog of committed expansion projects, which is currently $8 billion. During 2008, our backlog increased primarily as a result of receiving long-term binding commitments for our Ruby Pipeline project and the Tennessee Gas Pipeline (TGP) Line 300 expansion. In our exploration and production business, we experienced continued success based on a favorable commodity price environment, an ongoing focus on increasing volumes, and effective cost management. In our Marketing segment, we incurred significant non-cash mark-to-market losses in the second quarter due primarily to volatility in locational power prices in the Pennsylvania New Jersey Maryland (PJM) power market.

Outlook. For 2008, we expect the current operating trends in our core pipeline and exploration and production businesses to continue with a focus on growth of these businesses. We anticipate that our pipeline operations will continue to provide strong operating results based on significant planned pipeline growth capital expenditures over the next five years including our $8 billion committed project backlog, current levels of contracted capacity, and recent rate and regulatory actions. In the pipeline industry, a favorable macroeconomic environment supports continued industry growth and we believe our systems are situated in locations that will allow us to be a participant in this growth. We will continue to pursue additional expansion projects, including proposed joint venture development projects that would use our incumbent pipeline infrastructure to connect supply areas to areas of high demand in the West, Northeast and Southeast. Finally, we are committed to growing our MLP through organic growth opportunities, potential acquisitions, or through future asset contributions. Our MLP provides us financial flexibility, a competitive cost of capital on expansion opportunities, and is a strategic growth vehicle for El Paso.

In our exploration and production business, we will continue to seek opportunities in our domestic regions to increase production levels, provide near-term cash flows and generate competitive investment returns. In addition, our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and cash flows. In 2008, while our international capital is expected to be approximately 50 percent higher than 2007, we expect our domestic programs to constitute approximately 80 percent of our total planned capital and substantially all of our expected production.

In the first half of 2008, we received net proceeds of approximately $640 million on the sale of certain non-core properties primarily in our Texas Gulf Coast and Gulf of Mexico regions as part of our efforts to high grade our asset portfolio. In June 2008, we also acquired interests in domestic natural gas and oil properties in the Onshore Western region for approximately $43 million. These transactions, together with the Peoples Energy Production Company (Peoples) acquisition in the third quarter of 2007, increased the onshore U.S. weighting of our inventory of future capital projects and are expected to reduce our per-unit lease operating expenses as well as increase our future production growth rate.

For a more detailed discussion of our operations, refer to our Annual Report on Form 10-K. For a more detailed discussion of liquidity and capital resources related matters, see below.

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Segment Results

We have two core operating business segments, Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages our legacy trading activities and a Power segment that has interests in assets in South America and Asia. Our 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 earnings before interest expense and income taxes (EBIT) as a measure to assess the operating results and effectiveness of our business segments, which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to investors because it allows them to evaluate more effectively our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense from this measure so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income and operating cash flows.

Below is a reconciliation of our EBIT (by segment) to our consolidated net income for the periods ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions)			
Segment				
Pipelines	$ 295	$ 318	$ 676	$ 682
Exploration and Production	304	235	546	414
Marketing	(153)	5	(213)	(130)
Power	12	16	10	34
Segment EBIT	458	574	1,019	1,000
Corporate and other	41	(104)	80	(314)
Consolidated EBIT	499	470	1,099	686
Interest and debt expense	(221)	(231)	(454)	(514)
Income taxes	(87)	(70)	(235)	(51)
Income from continuing operations	191	169	410	121
Discontinued operations, net of income taxes		(3)		674
Net income	$ 191	$ 166	$ 410	$ 795

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Pipelines Segment

Operating Results. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT, or that could potentially impact EBIT in future periods.

	Quarters Ended June 30, 2008	Quarters Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(In millions, except volume amounts)			
Operating revenues	$ 646	$ 614	$ 1,366	$ 1,258
Operating expenses	(383)	(338)	(746)	(658)
Operating income	263	276	620	600
Other income	40	42	73	82
EBIT before minority interest	303	318	693	682
Minority interest	(8)		(17)	
EBIT	$ 295	$ 318	$ 676	$ 682
Throughput volumes (BBtu/d)[1]	17,981	17,161	18,652	17,597

[1] Throughput volumes include volumes associated with our proportionate share of unconsolidated affiliates.

	Quarter Ended June 30, 2008 Variance				Six Months Ended June 30, 2008 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 20	$ (5)	$ 2	$ 17	$ 45	$ (12)	$ 1	$ 34
Reservation and usage revenues	5			5	15			15
Gas not used in operations and revaluations	11	(16)		(5)	19	(12)		7
Bankruptcy settlements		1		1	30	1		31
Operating and general and administrative expenses		(19)		(19)		(30)		(30)

Gain/loss on long-lived assets		(3)		(3)		(26)		(26)
Equity earnings from Citrus			(3)	(3)			(12)	(12)
Minority interest			(8)	(8)			(17)	(17)
Other[1]	(4)	(3)	(1)	(8)	(1)	(9)	2	(8)
Total impact on EBIT	$ 32	$ (45)	$ (10)	$ (23)	$ 108	$ (88)	$ (26)	$ (6)

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

Expansions. In 2008, we benefited from increased reservation revenues and throughput volumes due to projects placed in service including the Wyoming Interstate Company, Ltd. (WIC) Kanda lateral project in January 2008, Phase II of the Cypress project in May 2008, and various projects placed in service throughout 2007 including Phase I of the Cypress project, the Louisiana Deepwater Link project, the Triple-T extension project and the Northeast ConneXion-New England project.

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We have continued to make progress on and grow our significant backlog of expansion projects to $8 billion. El Paso s committed backlog of new pipeline growth projects are all substantially fully contracted with customers and will be placed in service over the next five years. For the six months ended June 30, 2008, we have spent approximately $0.6 billion on these projects and currently anticipate spending $0.8 billion for the remainder of 2008. Listed below are significant additions and updates to our December 31, 2007 backlog of projects originally discussed in our 2007 Annual Report on Form 10-K:

Significant New Backlog Projects:

Ruby Pipeline project. We obtained sufficient long-term capacity commitments from customers and committed to move forward with the $3 billion Ruby Pipeline project, which is anticipated to be placed in service in March 2011. We plan to file a certificate application with the FERC in January 2009.

TGP Line 300 expansion. In August 2008, we announced the expansion of TGP s Line 300 pipeline. The estimated total capital cost for this expansion project is approximately $750 million with anticipated in-service dates in 2010 for Phase I and 2011 for Phase II.

CIG Raton Basin expansion. In July 2008, we announced the expansion of the CIG Raton Basin Pipeline. The estimated capital cost for the Raton Basin Pipeline expansion project is $146 million and we expect to place this project in service in the second quarter of 2010.

WIC expansions. We announced the expansions of the WIC system in July 2008. This project has an estimated total capital cost of $55 million and will consist of two projects with separate in-service dates of November 2010 and March 2011.

Significant Backlog Project Updates:

High Plains and Totem Gas Storage. We received FERC approval on the High Plains Pipeline project in March 2008 and the Totem Gas Storage project in April 2008. The estimated total capital cost for the High Plains Pipeline project is $216 million ($108 million to be paid by us) and the estimated in-service date is December 2008. The estimated total capital cost for the Totem Gas Storage project is $154 million ($77 million to be paid by us) and the estimated in-service date is July 2009.

South System III. The South System III expansion project will be completed in three phases. During the second quarter of 2008, we changed the scope of this project at the request of the customer which increased the total estimated cost to $352 million. We anticipate filing an application with the FERC during the fourth quarter of 2008 for certificate authorization to construct and operate these facilities. The project has estimated in-service dates of January 2011 for Phase I, June 2011 for Phase II and June 2012 for Phase III.

Southeast Supply Header. We own an undivided interest in the northern portion of the Southeast Supply Header project jointly owned by Spectra Energy Corp. (Spectra) and Centerpoint Energy. The construction of this project is managed by Spectra and our share of the estimated cost for this project is $241 million. This project is expected to be completed in two phases. The FERC issued an order approving the first phase in September 2007. The estimated in-service dates are September 2008 for Phase I and June 2011 for Phase II.

Florida Gas Transmission Phase VIII. We have a 50 percent interest in this project through our equity investment in Citrus. Our proportional share of the estimated cost of this project has increased to $1.2 billion due to higher than expected pipe and other costs.

For a further discussion of these projects, see our 2007 Annual Report on Form 10-K.

Successful execution on our $8 billion committed pipeline backlog will require effective project management. In addition, effective supply chain sourcing will also be important to controlling costs. For our Ruby Pipeline project, we have ordered all the pipe for the project, substantially all of which is on a fixed price basis. We have also ordered all the pipe for our TGP Line 300 expansion project on a fixed price basis. See Liquidity and Capital Resources for a discussion regarding financing of the capital required to execute on our committed backlog.

Reservation and Usage Revenues. During 2008, our EBIT was favorably impacted by an increase in overall reservation and usage revenues. During 2008, we benefited from additional capacity sold in the northern and southern regions of our TGP system, additional interruptible and firm commodity services provided in several of our pipeline systems, and increased demand for the off-system capacity on our CIG system. Partially offsetting these favorable impacts were lower surcharges from certain firm customers on our TGP system and lower reservation revenues on our Mojave system due to a decrease in tariff rates under its 2007 rate case settlement and the expiration of certain firm contracts.

Gas Not Used in Operations and Revaluations. During the six months ended June 30, 2008, our EBIT was favorably impacted by higher volumes of gas not used in our TGP operations compared to the same period in 2007. Effective March 1, 2008 and April 1, 2008, CIG and WIC implemented FERC-approved fuel and related gas cost recovery mechanisms which recover all cost impacts, or flow through to shippers any revenue impacts, of all fuel imbalance revaluations and related gas balance items and should reduce earnings volatility resulting from these items over time.

Bankruptcy Settlements. During the first six months of 2008, we recognized revenue of $35 million related to distributions received under Calpine Corporation s (Calpine) approved plan of reorganization. This settlement was related to Calpine s rejection of its transportation contracts with us. During 2008 and 2007, we recorded income of approximately $8 million and $2 million as a result of settlements received from the Enron Corporation bankruptcy. In the second quarter of 2007, we received $10 million to settle our bankruptcy claim against US Gen New England, Inc.

Operating and General and Administrative Expenses. For the quarter and six months ended June 30, 2008, our operating and general and administrative expenses were higher than the same periods in 2007 primarily due to increased labor costs and additional maintenance associated with required work on both the TGP and SNG systems.

Gain/Loss on Long-Lived Assets. During the six months ended June 30, 2008, we recorded impairments of $24 million, including an impairment related to our Essex-Middlesex Lateral project due to a prolonged permitting process. In February 2007, we recorded a $7 million pre-tax gain on the sale of a pipeline lateral.

Equity Earnings from Citrus. During the six months ended June 30, 2008, equity earnings on our Citrus investment decreased as compared to the same period in 2007 primarily due to a favorable settlement in 2007 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. In the second quarter of 2007, we also recorded $3 million of equity earnings due to Citrus sale of a receivable related to the bankruptcy of Enron North America.

Minority Interest. During the quarter and six months ended June 30, 2008, we recorded approximately $8 million and $17 million of minority interest expense related to our MLP formed in November 2007.

Other Regulatory Matters. In addition to the matters discussed above, 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 positively or negatively impact our profitability. Currently, while certain of our pipelines are expected to continue operating under their existing rates, other pipelines have projected upcoming rate actions with anticipated effective dates in 2009 through 2011.

In June 2008, EPNG filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposes an increase in EPNG s base tariff rates which would increase revenues by $83 million annually over current tariff rates. In August 2008, the FERC issued an order accepting and suspending the effective date of the proposed rates to January 1, 2009, subject to refund and the outcome of a hearing and technical conference.

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Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance 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. We also enter into financial derivative contracts to protect against significant downward price movements and allow us to achieve acceptable economic returns. Our strategy focuses on building and applying competencies in assets with repeatable programs, sharpening our execution skills to improve capital and expense efficiency and maximizing returns, and adding assets with inventory that match our competencies and divesting assets that do not.

Our domestic natural gas and oil reserve portfolio blends lower decline rate, typically longer lived assets in our Onshore regions, with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. At the beginning of 2008, our Onshore region was split into two operating areas, Onshore Central and Onshore Western. Onshore Central includes the Arklatex, Black Warrior and Mid-Continent areas, and Onshore Western includes the Rockies and Raton Basin areas. In 2008, our international capital is expected to increase approximately 50 percent over 2007 and will constitute approximately 20 percent of our total capital program. Successful execution, primarily in Brazil, will require effective project management, partner relations and successful negotiations with regulatory agencies.

During the first six months of 2008, we completed the sale of certain non-core properties for net cash proceeds of approximately $640 million, primarily in our Texas Gulf Coast and Gulf of Mexico regions, as part of our efforts to high grade our asset portfolio. These properties had estimated proved reserves of approximately 309 Bcfe and estimated asset retirement obligations of $109 million at December 31, 2007. The cash proceeds from the sale of these properties were used to repay debt incurred for the acquisition of Peoples in the third quarter of 2007. In June 2008, we also acquired interests in domestic natural gas and oil properties in the Onshore Western region for approximately $43 million. These transactions, together with our acquisition of Peoples, increased the onshore U.S. weighting of our inventory of future capital projects and are expected to reduce our per-unit lease operating expenses as well as increase our future production growth rate.

Significant Operational Factors Affecting the Periods Ended June 30, 2008

Production. Our average daily production volume for the six months ended June 30, 2008 was 786 MMcfe/d (which does not include 73 MMcfe/d from our share of production volume from our equity investment in Four Star). Average daily production for the six months ended June 30, 2008 associated with divested properties was 48 MMcfe/d. Below is an analysis of our production volumes by region for the periods ended June 30:

	Six Months Ended June 30,	
	2008	2007
	(MMcfe/d)	
United States		
Onshore Central	239	218
Onshore Western	151	147
Texas Gulf Coast	230	196
Gulf of Mexico and south Louisiana	154	192
International		
Brazil	12	15
Total Consolidated	786	768
Four Star	73	70

The increased 2008 production volumes in our Onshore Central, Western and Texas Gulf Coast operating regions were primarily due to our Peoples acquisition in the third quarter of 2007 and a successful Arklatex drilling program. Our Gulf of Mexico and south Louisiana region production volumes decreased due to natural production declines and asset sales partially offset by our successful drilling program at High Island and West Cameron areas. In Brazil, production volumes decreased primarily due to natural production declines.

2008 Drilling Results

Onshore Central. We achieved a 100 percent success rate on 142 gross wells drilled.

Onshore Western. We achieved a 100 percent success rate on 41 gross wells drilled.

Texas Gulf Coast. We achieved a 92 percent success rate on 49 gross wells drilled.

Gulf of Mexico and south Louisiana. We achieved a 50 percent success rate on 4 gross wells drilled.

Brazil. Our drilling activity operations in Brazil is primarily in the Camamu and Espirito Santo Basins.

Camamu Basin- In 2008, we retained a 100 percent working interest in two development areas in the BM-CAL-4 block and relinquished the remainder of the acreage in the block. The two development areas include the Camarao and Pinauna Fields. In 2007, we completed the drilling of two successful exploratory wells south of the Pinauna Field that extended the southern limits of the Pinauna project. We continue to advance the Pinauna project and are in the process of obtaining all regulatory and environmental approvals that are required before we can enter the next major phase of development.

We own an approximate 18 percent working interest in the BM-CAL-5 and BM-CAL-6 blocks, operated by Petrobras. In the first half of 2008, we participated in drilling an exploratory well in the BM-CAL-6 block that was unsuccessful. We continue to evaluate other opportunities in this block. We also plan to participate in drilling up to two exploratory wells in the BM-CAL-5 block during the second half of 2008.

Espirito Santo Basin- In 2007, we completed drilling and testing two exploratory wells with Petrobras in the ES-5 block. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. We are currently in negotiations with Petrobras on a unitization agreement. The plan of development for this area includes four wells that are projected to be completed and producing during the first quarter of 2009. It is expected that the gas price we will receive will be indexed to a basket of international fuel oils. During the second half of 2008, we plan to participate with Petrobras in the drilling of two more exploratory wells in this block in which we have a 35 percent working interest.

Egypt. During the second quarter of 2008, we completed the acquisition of seismic data on our operated South Mariut block and are in the process of interpreting the data. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We have selected our first well location and expect to commence drilling operations in the fourth quarter of 2008. In addition, in the first half of 2008, we participated in drilling an exploratory well in the South Feiran block that was unsuccessful. The South Feiran block is our non-operated block in the Gulf of Suez in which we own a 20 percent working interest. We continue to evaluate other opportunities in this block.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil production volumes. These costs are calculated on a per Mcfe basis and include total operating expenses less depreciation, depletion and amortization expense, ceiling test or impairment charges, transportation costs and cost of products. During the six months ended June 30, 2008 and 2007, cash operating costs per unit were $1.96/Mcfe for both periods. Higher production taxes in 2008 resulting from higher natural gas and oil revenues were partially offset by lower lease operating expenses and lower general and administrative expenses. Lease operating expenses decreased in 2008 primarily due to lower maintenance and repair expenses, lower workover activities, and the impact of divested properties in the Gulf of Mexico and south Louisiana region.

Capital Expenditures. Our total natural gas and oil capital expenditures were $745 million for the six months ended June 30, 2008, of which $689 million were domestic capital expenditures.

Outlook

For the full year 2008, we anticipate the following on a worldwide basis:

- Average daily production volumes for the year at the low end of our previously disclosed guidance range of approximately 795 MMcfe/d to 850 MMcfe/d, excluding approximately 65 MMcfe/d to 70 MMcfe/d from our equity investment in Four Star.

- Capital expenditures, excluding acquisitions, of approximately $1.9 billion. While approximately 80% of our planned 2008 capital program is allocated to our domestic program, we plan to spend approximately $350 million to $385 million in international capital in 2008, primarily in our Brazil exploration and development program. As part of our domestic capital program, we will allocate a greater percentage of our capital to our Onshore Central, Onshore Western and Texas Gulf Coast regions, as compared to our 2007 capital program.

- Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.95/Mcfe to $2.05/Mcfe for the year. Average cash operating costs have increased during 2008 and could change further, primarily as a result of severance taxes which are sensitive to commodity prices; and

- Depreciation, depletion and amortization rate of between $2.90/Mcfe and $3.10/Mcfe.

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.

In the first half of 2008, we entered into option and swap contracts on approximately 54 TBtu of our anticipated 2008 natural gas production and 168 TBtu of anticipated 2009 natural gas production. We also entered into 597 MBbls and 3,431 MBbls of fixed price swaps on our anticipated 2008 and 2009 oil production. While a significant amount of these contracts were designated as hedges, a portion will be marked-to-market in our earnings each period.

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The following tables reflect the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of June 30, 2008. The tables below do not include contracts entered into by our Marketing segment. For the consolidated impact of the entirety of El Paso s production-related price risk management activities, see Liquidity and Capital Resources.

Derivatives designated as accounting hedges

	Fixed Price Swaps[1]		Floors[1]		Ceilings[1]	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
Natural Gas						
2008	13	$ 7.50	63	$8.00	63	$10.84
2009	5	$ 3.56	126	$8.93	101	$14.58
2010	5	$ 3.70				
2011-2012	6	$ 3.88				
Oil						
2008	1,260	$ 87.80				
2009	1,934	$109.32				

(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.

Derivatives not designated as accounting hedges

	Fixed Price Swaps[1]		Floors[1]		Ceilings[1]		Basis Swaps[1][2]					
							Texas Gulf Coast		Onshore-Raton		Rockies	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2008	4	$ 8.24	18	$8.00	18	$10.45	30	$ (0.33)	13	$ (1.14)	6	$ (1.37)
2009			42	$9.61	42	$17.40			15	$ (1.00)		
Oil												
2009	1,497	$110.71										

(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.

Gains and losses associated with derivative contracts designated as hedges are deferred in accumulated other comprehensive income and 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. Gains and losses associated with derivative contracts not designated as hedges are recognized in earnings each period.

In July 2008, we entered into swaps on approximately 4 TBtu of anticipated 2009 natural gas production at a fixed price of $12.06 per MMBtu. These contracts were not designated as accounting hedges.

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Operating Results and Variance Analysis

The tables below and the discussion that follows provide our financial results and analysis of significant variances in these results during the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions)			
Operating Revenues:				
Natural gas	$ 574	$ 459	$ 1,042	$ 867
Oil, condensate and NGL	137	111	296	199
Changes in fair value of derivative contracts not designated as accounting hedges	(75)	(5)	(110)	(2)
Other	19	10	30	16
Total operating revenues	655	575	1,258	1,080
Operating Expenses:				
Depreciation, depletion and amortization	(197)	(189)	(409)	(359)
Production costs	(93)	(84)	(184)	(170)
Transportation costs	(21)	(15)	(40)	(34)
Cost of products	(10)	(4)	(15)	(9)
General and administrative expenses	(43)	(49)	(90)	(95)
Other	(10)	(5)	(13)	(7)
Total operating expenses	(374)	(346)	(751)	(674)
Operating income	281	229	507	406
Other income(1)	23	6	39	8
EBIT	$ 304	$ 235	$ 546	$ 414

(1) Other income includes equity earnings from our investment in Four Star.

	Quarters Ended June 30,			Six Months Ended June 30,		
	2008	2007	Percent Variance	2008	2007	Percent Variance
Consolidated volumes, prices and costs per unit:						
Natural gas						
Volumes (MMcf)	60,270	59,804	1%	122,079	116,517	5%
Average realized prices including hedges ($/Mcf)	$ 9.53	$ 7.67	24%	$ 8.54	$ 7.44	15%
Average realized prices excluding hedges ($/Mcf)	$ 10.46	$ 7.17	46%	$ 9.07	$ 6.83	33%

Average transportation costs ($/Mcf)	$ 0.32	$ 0.24	33%	$ 0.30	$ 0.27	11%
Oil, condensate and NGL Volumes (MBbls)	1,516	1,948	(22)%	3,508	3,736	(6)%
Average realized prices including hedges ($/Bbl)	$ 90.64	$ 56.87	59%	$ 84.45	$ 53.25	59%
Average realized prices excluding hedges ($/Bbl)	$ 105.12	$ 57.50	83%	$ 92.59	$ 53.94	72%
Average transportation costs ($/Bbl)	$ 1.07	$ 0.68	57%	$ 0.87	$ 0.72	21%
Total equivalent volumes						
MMcfe	69,366	71,493	(3)%	143,128	138,935	3%
MMcfe/d	762	786	(3)%	786	768	2%
Production costs and other cash operating costs ($/Mcfe)						
Average lease operating expenses	$ 0.79	$ 0.85	(7)%	$ 0.80	$ 0.89	(10)%
Average production taxes[1]	0.54	0.33	64%	0.48	0.33	45%
Total production costs	1.33	1.18	13%	1.28	1.22	5%
Average general and administrative expenses	0.63	0.68	(7)%	0.64	0.69	(7)%
Average taxes, other than production and income taxes	0.05	0.06	(17)%	0.04	0.05	(20)%
Total cash operating costs	$ 2.01	$ 1.92	5%	$ 1.96	$ 1.96	%
Depreciation, depletion and amortization ($/Mcfe)	$ 2.84	$ 2.64	8%	$ 2.85	$ 2.58	10%
Unconsolidated affiliate volumes (Four Star)						
Natural gas (MMcf)	4,926	4,806		10,047	9,747	
Oil, condensate and NGL (MBbls)	249	268		534	501	
Total equivalent volumes						
MMcfe	6,419	6,417		13,251	12,755	
MMcfe/d	71	71		73	70	

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

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Quarter and Six Months Ended June 30, 2008 Compared to Quarter and Six Months Ended June 30, 2007

Our EBIT for the quarter and six months ended June 30, 2008 increased $69 million and $132 million as compared to the same periods in 2007. The table below lists the significant variances in our operating results for the quarter and six months ended June 30, 2008 as compared to the same periods in 2007:

	Quarter Ended June 30, 2008 Variances				Six Months Ended June 30, 2008 Variances			
	Operating Revenue	Operating Expense	Other	EBIT	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)							
Natural Gas Revenue								
Higher realized prices in 2008	$ 198	$	$	$ 198	$ 274	$	$	$ 274
Impact of hedges	(86)			(86)	(136)			(136)
Higher volumes in 2008	3			3	37			37
Oil, Condensate and NGL Revenues								
Higher realized prices in 2008	72			72	135			135
Impact of hedges	(21)			(21)	(26)			(26)
Lower volumes in 2008	(25)			(25)	(12)			(12)
Other Revenue								
Changes in fair value of derivatives not designated as accounting hedges	(70)			(70)	(108)			(108)
Other	9			9	14			14
Depreciation, Depletion and Amortization Expense								
Higher depletion rate in 2008		(15)		(15)		(40)		(40)
Lower (higher) production volumes in 2008		5		5		(10)		(10)
Production Costs								
Lower lease operating expenses in 2008		5		5		9		9
Higher production taxes in 2008		(14)		(14)		(23)		(23)
Other								
Earnings from investment in Four Star			13	13			24	24
Other		(9)	4	(5)		(13)	7	(6)
Total Variances	$ 80	$ (28)	$ 17	$ 69	$ 178	$ (77)	$ 31	$ 132

Natural gas, oil, condensate and NGL revenues. During the quarter and six months ended June 30, 2008, revenues increased as compared with the same periods in 2007 due primarily to higher commodity prices, including the effects of our hedging program. Losses on hedging settlements were $78 million and $93 million during the quarter and six months ended June 30, 2008, as compared to gains of $29 million and $69 million in the same periods in 2007. During the quarter and six months ended June 30, 2008, we also benefited from an increase in production volumes in our Onshore Central and Texas Gulf Coast regions compared to the same periods in 2007, primarily as a result of our Peoples acquisition.

Other revenue. During the quarter and six months ended June 30, 2008, we recognized mark-to-market losses of $75 million and $110 million compared to losses of $5 million and $2 million during the same periods in 2007 related to the changes in fair value of derivatives that are not designated as hedges. During the quarter and six months ended June 30, 2008, we paid $14 million and $18 million on contracts that settled during the period, compared to payments of $12 million and $19 million on contracts that settled during the same periods in 2007.

Depreciation, depletion and amortization expense. During 2008, our depletion rate increased as compared to the same periods in 2007 as a result of the Peoples and Zapata County, Texas acquisitions in 2007 and higher finding and development costs.

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Production costs. Our production taxes increased during 2008 as compared to the same periods in 2007 primarily due to higher natural gas and oil revenues. The increase in production taxes was partially offset by a reduction in lease operating expenses primarily as a result of lower maintenance and repair expenses, lower workover activities and the impact of divested properties in the Gulf of Mexico and south Louisiana region.

Other. Our equity earnings from Four Star increased as compared to the quarter and six months ended June 30, 2007 primarily due to higher natural gas prices and an increase in our equity ownership in Four Star from 43 percent to 49 percent in the third quarter of 2007.

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Marketing Segment

Overview. Our Marketing segment s primary focus is marketing our Exploration and Production segment s natural gas and oil production and managing the Company s overall price risks, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate remaining legacy contracts which have significantly impacted our operating results and the fair value of our portfolio. To the extent it is economical to do so, we may enter into additional agreements to reduce our exposure or liquidate our 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, see our 2007 Annual Report on Form 10-K.

Operating Results. During the quarter and six months ended June 30, 2008, we generated EBIT losses of $153 million and $213 million primarily driven by changes in the fair value of our PJM power contracts and production-related natural gas and oil derivative contracts. These losses were due primarily to significant changes in locational PJM power price differences as well as increases in natural gas and oil prices. Our 2008 results were also impacted by changes in the interest rates used to determine the fair market value of these contracts which increased our losses during the first quarter of 2008 and partially offset our losses incurred in the second quarter of 2008.

Our remaining exposure in this segment relates to further changes in locational power price differences in PJM (a regional transmission organization that serves 13 states in the Northeast and operates a wholesale power market), changes in natural gas and oil prices, and changes in the interest rates used to determine the fair value of our derivative contracts. To the extent there is continued volatility in these prices or fluctuations in interest rates, we will continue to experience volatility in our operating results in the future. As of June 30, 2008, we estimate that a 10 percent change, collectively, to natural gas and oil prices and locational PJM power price differences, would change the fair value of our derivatives by approximately $32 million. As of June 30, 2008, a 1 percent change in interest rates would change the fair market value of our derivatives by approximately $25 million.

Below is further information about our overall operating results during each of the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
	(In millions)			
Production-Related Natural Gas and Oil Derivative Contracts:				
Changes in fair value of options and swaps	$ (52)	$ 9	$ (73)	$ (78)
Contracts Related to Legacy Trading Operations:				
Natural gas transportation-related contracts:				
Demand charges	(10)	(28)	(19)	(55)
Settlements, net of termination payments	10	16	24	36
Changes in fair value of other natural gas derivative contracts	11	2	11	(22)
Changes in fair value of power contracts(1)	(105)	(15)	(146)	(32)
Total revenues	(146)	(16)	(203)	(151)
Operating expenses	(8)	(4)	(11)	(5)
Operating loss	(154)	(20)	(214)	(156)
Other income, net(2)	1	25	1	26
EBIT	$ (153)	$ 5	$ (213)	$ (130)

(1) Includes $21 million of revenue recognized in the second quarter of 2007 on the settlement of outstanding California power price disputes.

(2) Includes a $23 million gain in the second quarter of 2007 on the sale of our investment in the NYMEX.

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Production-related Natural Gas and Oil Derivative 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 derivative contracts entered into by our Exploration and Production segment which are further described in the discussion of that segment above. During the second quarter of 2008, we paid approximately $57 million to terminate 17 TBtu of 2009 natural gas option contracts with a floor price of $6.00 per MMBtu and a ceiling price of $8.75 per MMBtu. As of June 30, 2008, our remaining contracts in this segment included 453 MBbl of 2008 oil option contracts with a floor price of $55 per Bbl and an average ceiling price of $56.40 per Bbl. For the consolidated impact of all of El Paso s production-related price risk management activities, refer to our Liquidity and Capital Resources discussion.

Changes in the fair value of these contracts are marked-to-market in our financial results and are impacted by the volatility in commodity prices from period-to-period. These changes in fair value generally move in the opposite direction from changes in forward commodity prices. During the six months ended June 30, 2008 and 2007, increases in commodity prices reduced the fair value of our option contracts resulting in losses. During the six months ended June 30, 2008, we paid approximately $25 million on contracts settled during that period, while during the six months ended June 30, 2007 we received approximately $16 million.

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. Our exposure to demand charges has been significantly reduced compared with 2007 largely due to the transfer of our Alliance transportation contract to a third party in 2007. As of June 30, 2008, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. In 2008, we anticipate demand charges related to this capacity of approximately $41 million which we expect to steadily decline to an average of $24 million annually from 2009 through 2012. The profitability of these contracts is dependent upon the recovery of demand charges as well as our ability to use or remarket the contracted pipeline capacity, which is impacted by a number of factors including differences in natural gas prices at contractual receipt and delivery locations, the working capital needed to use this capacity, and the capacity required to meet our long-term obligations. Our transportation contracts are accounted for on an accrual basis and impact our revenues as delivery or service under the contracts occurs.

Other natural gas derivative contracts. In addition to our natural gas transportation contracts, we have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices. While we have substantially offset all of the fixed price exposure in these contracts, they are still subject to changes in fair value due to changes in the interest rates used to value these contracts. During the first quarter of 2007, we assigned a weather call derivative which required us to supply gas in the northeast region if temperatures fell to specific levels resulting in a loss of $13 million.

Power contracts. Our power portfolio consists of contracts that extend into 2016 that require us to supply both energy and capacity in the PJM region, as well as swap locational differences in prices between specific locations in the PJM eastern region with the PJM west hub. Power prices in the PJM region are highly volatile due to volatile fuel prices and transmission congestion at certain locations in the region, and continued changes in these prices could continue to significantly impact the fair value of our power contracts. The fair value of these contracts is also impacted by changes in interest rates.

During the quarter and six months ended June 30, 2008, we incurred mark-to-market losses of $105 million and $146 million on our PJM contracts due primarily to the difference in forward power prices at specific delivery locations in the PJM eastern region compared to those in the PJM west hub more than doubling since the end of 2007. Also impacting our results for the six months ended June 30, 2008, was a capacity purchase agreement executed during the first quarter of 2008 with a counterparty that, when combined with capacity prices established in auctions held by the PJM Independent System Operator for periods prior to June 2011, economically hedges our exposure to supplying capacity in the PJM region for the remainder of the contract term. Prior to 2008, we had economically hedged the fixed commodity price exposure of supplying power under these contracts. For the quarter and six months ended June 30, 2008, cash settlements relating to our PJM contracts were $20 million and $33 million, of which $9 million and $12 million were related to our obligations to swap locational differences in prices within the PJM region.

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Power Segment

As of June 30, 2008, our Power segment consists of assets in South America and one remaining Asian investment. We continue to pursue the sale of these remaining power assets. During the second quarter of 2008, we sold our remaining power investment in Central America and an Asian power investment. Until the sale of our remaining international investments is 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. Additionally, during the first quarter of 2008, our power purchase agreements for the Manaus and Rio Negro power plants in Brazil expired and we transferred the ownership of these plants to the plants power purchaser. As of June 30, 2008, our net remaining investment, guarantees and letters of credit related to power projects in this segment totaled approximately $465 million which consisted of approximately $448 million in equity investments and notes and accounts receivable and approximately $17 million in financial guarantees and letters of credit, as follows (in millions):

South America	
Porto Velho	$ 230
Manaus & Rio Negro	63
Pipeline projects	146
Asia	26
Total investment, guarantees and letters of credit	$ 465

Operating Results. For the quarter and six months ended June 30, 2008, our Power segment generated EBIT of $12 million and $10 million due primarily to gains recognized on the sale of investments in Asia and Central America. For the quarter and six months ended June 30, 2007, we had EBIT of $16 million and $34 million generated primarily from interest on a note receivable with our Porto Velho project in Brazil. In 2007 and 2008, we did not recognize earnings from our Asian and Central American investments, and in 2008 we did not recognize earnings from our Porto Velho project, based on our inability to realize those earnings. For a discussion of developments and other matters that could impact our remaining investments, see Item 1, Financial Statements, Note 12.

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 activities for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions)			
Loss on extinguishment of debt	$	$ (86)	$	$ (287)
Change in litigation, insurance and other reserves	46	(9)	57	(35)
Foreign currency fluctuations on Euro-denominated debt		(1)	(6)	(3)
Gain on disposition of a portion of our telecommunications business			18	
Other	(5)	(8)	11	11
Total EBIT	$ 41	$ (104)	$ 80	$ (314)

Extinguishment of Debt. During the first half of 2007, we repurchased or refinanced debt of approximately $5 billion. During this period, we recorded charges of $287 million in our income statement for the loss on extinguishment of these obligations, which included $86 million recorded in the second quarter related to repurchasing EPEP s $1.2 billion notes. For further information on our debt, see Item 1, Financial Statements, Note 7.

Litigation, Insurance, and Other Reserves. We have a number of pending litigation matters and reserves related to our historical business operations. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may further impact our future results.

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In the first six months of 2008, we recorded a net favorable adjustment related to resolving certain legacy litigation matters, including settlement of our Case Corporation indemnification dispute (See Item 1, Financial Statements, Note 9.) Partially offsetting these settlements were mark-to-market losses for an indemnification in conjunction with the sale of a legacy ammonia facility. The mark-to-market losses were based on significant increases in ammonia prices during the first quarter of 2008. Further changes in ammonia prices may continue to impact this contract, which could impact our results in the future.

Interest and Debt Expense

Our interest and debt expense was lower in 2008 compared with 2007 primarily due to lower average debt balances in 2008 when compared to 2007.

Income Taxes

	Quarters Ending June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions, except for rates)			
Income taxes	$87	$70	$235	$51
Effective tax rate	31%	29%	36%	30%

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 (loss) from our discontinued operations was $(3) million and $674 million for the quarter and six months ended June 30, 2007. 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 8 which is incorporated herein by reference.

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Liquidity and Capital Resources

Overview. Over the past several years, we have focused on our core pipeline and exploration and production operations and on strengthening our balance sheet. Our cash flow from operations and our balance sheet have given us the financial flexibility to build an extensive backlog of committed pipeline projects and production-related growth projects while meeting ongoing obligations. We recently announced our plans to move forward with our Ruby Pipeline project and TGP Line 300 expansion increasing our committed pipeline backlog to $8 billion. Additionally, our cash flow levels, enhanced by the strong commodity price environment, have prompted our Board of Directors to increase our quarterly dividend and to authorize a $300 million stock repurchase program. To the extent it is necessary to fund the capital expenditure programs of our pipeline and exploration and production operations, meet operating needs and repay debt maturities, we have the ability to access available capacity under our credit agreements and to pursue additional bank financings, project financings or debt capital markets transactions, subject to market conditions. In addition, we can also pursue the sale of assets to generate proceeds and reduce our future capital commitments or pursue equity partnering opportunities on some of our expansion projects.

2008 Cash Flow Activities. During the first six months of 2008, we generated operating cash flow of approximately $1.3 billion, primarily as a result of cash provided by our pipeline and exploration and production operations. In addition, we generated approximately $0.7 billion in proceeds primarily from the sale of certain oil and gas properties and issued approximately $0.6 billion in unsecured notes. We utilized these amounts to fund maintenance and growth projects in our pipeline and exploration and production operations, which included the acquisition of a 50 percent interest in the Gulf LNG Clean Energy project, and to pay down amounts borrowed under our revolving credit facilities, scheduled maturities and previously announced repurchases of approximately $0.3 billion of notes of our subsidiaries, SNG and CIG. For the six months ended June 30, 2008, our cash flows from continuing operations are summarized as follows:

		2008 (In billions)
Cash Flow from Operations		
Continuing operating activities		
Income from continuing operations	$	0.4
Other income adjustments		0.9
Total cash flow from operations	$	1.3
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$	0.7
Continuing financing activities		
Net proceeds from the issuance of long-term debt[1]		2.7
Total other cash inflows	$	3.4
Cash Outflows		
Continuing investing activities		
Capital expenditures	$	1.2
Cash paid for acquisitions		0.3
		1.5
Continuing financing activities		
Payments to retire long-term debt and other financing obligations[1]		3.1

Dividends and other		0.1
		3.2
Total cash outflows	$	4.7
Net change in cash	$	

(1) Relates primarily to the net activity under our revolving credit facilities.

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Liquidity/Cash Flow Outlook. For the remainder of 2008, we expect continued strong operating cash flows from our core pipeline and exploration and production businesses. We also expect to generate approximately $0.2 billion in proceeds from international power asset sales. Assuming a continued strong commodity price environment in 2008, we anticipate we will generate cash flows in excess of amounts originally planned. We believe our anticipated operating cash flow and access to the capital sources discussed in *Overview* should allow us to fund our $8 billion, five year pipeline project backlog, repay upcoming debt maturities (including approximately $1.2 billion through June 30, 2009), and fund our authorized stock repurchase program.

Our capital expenditures (including acquisitions) for the six months ended June 30, 2008, and the amount we expect to spend for the remainder of 2008 to grow and maintain our businesses are as follows:

	Six Months Ended June 30, 2008	2008 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.2	$ 0.2	$ 0.4
Growth	0.6	0.8	1.4
Exploration and Production	0.7	1.2	1.9
Corporate and other[(1)]		0.1	0.1
	$ 1.5	$ 2.3	$ 3.8

(1) Relates primarily to building renovations at our corporate facilities.

Factors That Could Impact Our Future Liquidity. As noted above, we believe our cash sources will allow us to meet our future cash needs. However, our liquidity needs could increase or decrease based on changes in any of these factors, as well as in other factors such as the margining requirements of our price risk management activities. For a complete discussion of risk factors that could impact our liquidity, see our 2007 Annual Report on Form 10-K.

Price Risk Management Activities and 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. 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 June 30, 2008. 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.

	Fixed Price						Basis Swaps[(1)(2)]					
	Swaps[(1)]		Floors[(1)]		Ceilings[(1)]		Texas Gulf Coast		Onshore-Raton		Rockies	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2008	17	$ 7.66	81	$ 8.00	81	$10.75	30	$(0.33)	13	$(1.14)	6	$(1.37)
2009	5	$ 3.56	168	$ 9.10	143	$15.41			15	$(1.00)		
2010	5	$ 3.70										

2011-2012	6	$ 3.88				
Oil						
2008	1,260	$ 87.80	453	$55.00	453	$56.40
2009	3,431	$109.93				

(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 July 2008, we entered into swaps on approximately 4 TBtu of our anticipated 2009 natural gas production at a fixed price of $12.06 per MMBtu.

We currently post letters of credit for the required margin on certain of our derivative contracts. For the remainder of 2008, based on current prices, we expect approximately $0.1 billion of the total of $1.0 billion in collateral outstanding at June 30, 2008 to be returned to us, a substantial portion of which will be 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 June 30, 2008, a $0.10/MMBtu increase in the price curve of natural gas over the next several years would result in an increase in our margin requirements of approximately $6 million in the aggregate over the life of the contracts of which $2 million is associated with contracts expiring in 2008-2009 and $4 million is associated with contracts expiring in 2010 and beyond.

Contractual Obligations

The following information provides updates to our contractual obligations, and should be read in conjunction with the information disclosed in our 2007 Annual Report on Form 10-K.

Commodity-Based Derivative Contracts. We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. In the tables below, derivatives designated as accounting hedges primarily consist of options and swaps used to hedge natural gas production. Other commodity-based derivative contracts are not traded on active exchanges and 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 June 30, 2008:

	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						
Liabilities[(1)]	$ (433)	$ (122)	$ (26)	$	$	$ (581)
Other commodity-based derivatives						
Assets	47	126	63	19	2	257
Liabilities	(350)	(460)	(287)	(164)		(1,261)
Total other commodity-based derivatives[(1)(2)]	(303)	(334)	(224)	(145)	2	(1,004)
Total commodity-based derivatives	$ (736)	$ (456)	$ (250)	$ (145)	$ 2	$ (1,585)

(1) Includes positions whose fair value is primarily based on commodity prices quoted on exchanges such

as the NYMEX.

(2) Includes positions whose fair values are derived from third party pricing data and valuation techniques that consider specific contractual terms, statistical and simulation analysis, present value concepts, and other internal assumptions.

The following is a reconciliation of our commodity-based derivatives for the six months ended June 30, 2008:

	Derivatives Designated as Accounting Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at January 1, 2008	$ (23)	$ (869)	$ (892)
Fair value of contract settlements during the period	51	189	240
Changes in fair value of contracts	(630)	(319)	(949)
Option premiums (received) paid	21	(5)	16
Net changes in contracts outstanding during the period	(558)	(135)	(693)
Fair value of contracts outstanding at June 30, 2008	$ (581)	$ (1,004)	$ (1,585)

Other Purchase Obligations. We have entered into contracts to purchase approximately $1.0 billion of pipe associated with the Ruby Pipeline project and TGP s Line 300 project which are anticipated to be placed in service between 2010 and 2011. Our estimated annual obligations under these agreements are approximately $0.3 billion for the remainder of 2008, $0.6 billion in 2009 and $0.1 billion in 2010.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, the information disclosed in our 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. 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. 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 the remaining forecasted natural gas and oil production.

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 are long-term historical contracts that we either intend to assign to third parties or manage until their expiration. Prior to the second quarter of 2008, we managed the risks related to these contracts using a Value-at-Risk simulation. During the second quarter of 2008, we began utilizing a sensitivity analysis to manage the commodity price risk associated with our other commodity-based derivative contracts and discontinued using the Value-at-Risk simulation based on the continued simplification of our derivative portfolio and the gradual discontinuance of a substantial majority of our trading activities.

Sensitivity Analysis. The table below presents the hypothetical sensitivity of our production-related derivatives and our other commodity-based derivatives to changes in fair values arising from immediate selected potential changes in the market prices (primarily natural gas, oil, power and basis prices) used to value these contracts. This table reflects the sensitivities of the derivative contracts only and does not include any underlying hedged commodities.

		Change in Market Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivative net liabilities					
June 30, 2008	$(711)	$(994)	$(283)	$(438)	$273
December 31, 2007	$ (64)	$(181)	$(117)	$ 58	$122
Other commodity-based derivative net liabilities					
June 30, 2008	$(874)	$(900)	$ (26)	$(848)	$ 26
December 31, 2007	$(828)	$(846)	$ (18)	$(810)	$ 18

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Interest Rate Risk

Commodity-based Derivatives. The fair value of our derivative instruments is sensitive to changes in interest rates. The table below presents the hypothetical sensitivity of our commodity-based price risk management activities to changes in fair values arising from changes in the discount rates used to determine the fair value of our derivatives.

		Change in Discount Rate			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivative net liabilities					
June 30, 2008	$(711)	$(706)	$ 5	$(716)	$ (5)
December 31, 2007	$ (64)	$ (62)	$ 2	$ (66)	$ (2)
Other commodity-based derivative net liabilities					
June 30, 2008	$(874)	$(850)	$24	$(900)	$(26)
December 31, 2007	$(828)	$(805)	$23	$(853)	$(25)

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2008, 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 U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based on the results of our evaluation, our CEO and our CFO concluded that our disclosure controls and procedures are effective at a reasonable assurance level at June 30, 2008.

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 second quarter of 2008.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2007 Annual Report on Form 10-K filed with the SEC.

Natural Buttes. In May 2004, the EPA issued a Compliance Order (Order) to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. In July 2004, the EPA issued a confidential Pre-filing Settlement Offer which contained a proposed fine of $350,000. In September 2005, the matter was referred to the U.S. Department of Justice (DOJ). CIG entered into a tolling agreement with the United States and conducted settlement discussions with the DOJ and the EPA, and CIG had agreed in principle to a penalty of $470,000, which included $50,000 in incremental costs for a Supplemental Environmental Project. While conducting some testing at the facility, CIG discovered that three generators installed in 1992 may have been emitting oxides of nitrogen at levels which, if supported, would suggest the facility should have obtained a Prevention of Significant Deterioration permit when the generators were first installed, and CIG promptly reported those test data to the EPA. CIG is in discussions with the DOJ regarding a potential additional fine associated with excess emissions at the three generators. We believe that our accruals for these matters are adequate.

Item 1A. Risk Factors

CAUTIONARY STATEMENTS

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

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

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ

materially from estimates or projections contained in our forward-looking statements are described in our 2007 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. There have been no material changes in our risk factors since that report.

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

The following table summarizes, by month, our purchases of common stock during the quarter ended June 30, 2008:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value that May Yet Be Purchased Under the Program[1]
June 1, 2008 to June 30, 2008	203,700	$ 20.93	203,700	$ 295,736,559
Total	203,700	$ 20.93	203,700	$ 295,736,559
July 1, 2008 to July 31, 2008	1,465,253	$ 18.40	1,465,253	$ 268,775,904

(1) On May 14, 2008, the Board approved a $300 million stock repurchase program to be consummated to the extent that we generate cash in excess of that originally planned. The share repurchase program was publicly announced on May 15, 2008 and has no stated expiration date.

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Item 3. Defaults Upon Senior Securities

None.

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

Proposals presented for a stockholders vote at our Annual Meeting of Stockholders held on May 14, 2008, included the election of fourteen directors and the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year 2008.

Each of the fourteen directors nominated by El Paso was elected with the following voting results:

Nominee	For	Against	Abstain
Juan Carlos Braniff	569,327,575	6,459,771	5,522,500
James L. Dunlap	571,030,509	4,775,190	5,504,148
Douglas L. Foshee	568,359,565	7,463,357	5,486,924
Robert W. Goldman	562,387,948	13,373,915	5,547,984
Anthony W. Hall Jr.	570,993,058	4,745,643	5,571,145
Thomas R. Hix	571,820,265	4,006,496	5,483,085
William H. Joyce	558,624,609	17,095,130	5,590,107
Ronald L. Kuehn, Jr.	567,886,937	7,764,735	5,658,175
Ferrell P. McClean	571,506,700	4,198,528	5,604,618
Steven J. Shapiro	571,310,840	4,536,677	5,462,330
J. Michael Talbert	571,695,008	4,158,367	5,456,471
Robert F. Vagt	571,650,369	4,150,622	5,508,855
John L. Whitmire	571,677,980	4,106,308	5,525,559
Joe B. Wyatt	569,404,827	6,440,371	5,464,648

The appointment of Ernst & Young LLP as El Paso s independent registered public accounting firm for the fiscal year 2008 was ratified with the following voting results:

	For	Against	Abstain
Proposal to ratify the appointment of Ernst & Young LLP as our independent registered public accounting firm	573,288,277	2,686,997	5,334,572

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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SIGNATURES

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

	EL PASO CORPORATION
Date: August 8, 2008	/s/ D. Mark Leland D. Mark Leland Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: August 8, 2008	/s/ John R. Sult John R. Sult Senior Vice President and Controller (Principal Accounting Officer)

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EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed with this Report.

Exhibit Number	Description
4	Thirteenth Supplemental Indenture dated as of May 30, 2008 between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999.
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.