EL PASO CORP/DE
Form 10-Q
November 10, 2008

Table of Contents

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

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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 by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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

Common stock, par value $3 per share. Shares outstanding on November 5, 2008: 698,562,656

EL PASO CORPORATION
TABLE OF CONTENTS

Caption	**Page**
PART I FINANCIAL INFORMATION	

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

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

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

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

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Operating revenues	$ 1,598	$ 1,166	$ 4,020	$ 3,386
Operating expenses				
Cost of products and services	68	55	195	170
Operation and maintenance	329	348	882	978
Depreciation, depletion and amortization	292	293	903	850
Taxes, other than income taxes	70	53	230	185
	759	749	2,210	2,183
Operating income	839	417	1,810	1,203
Earnings (losses) from unconsolidated affiliates	52	(6)	141	75
Loss on debt extinguishment				(287)
Other income, net	(3)	73	52	179
Minority interest	(7)	(1)	(23)	(1)
Interest and debt expense	(221)	(228)	(675)	(742)
Income before income taxes from continuing operations	660	255	1,305	427
Income taxes	215	100	450	151
Income from continuing operations	445	155	855	276
Discontinued operations, net of income taxes				674
Net income	445	155	855	950
Preferred stock dividends	9	9	28	28
Net income available to common stockholders	$ 436	$ 146	$ 827	$ 922
Basic earnings per common share				
Income from continuing operations	$ 0.63	$ 0.21	$ 1.19	$ 0.36
Discontinued operations, net of income taxes				0.97
Net income per common share	$ 0.63	$ 0.21	$ 1.19	$ 1.33
Diluted earnings per common share				

Income from continuing operations	$ 0.58	$ 0.20	$ 1.12	$ 0.35
Discontinued operations, net of income taxes				0.96
Net income per common share	$ 0.58	$ 0.20	$ 1.12	$ 1.31
Dividends declared per common share	$ 0.05	$ 0.04	$ 0.13	$ 0.12

See accompanying notes.

Table of Contents

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

	September 30, 2008	December 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,160	$ 285
Accounts and notes receivable		
Customers, net of allowance of $10 in 2008 and $17 in 2007	587	468
Affiliates	164	196
Other	211	201
Inventory	168	131
Assets from price risk management activities	388	113
Deferred income taxes	181	191
Other	140	127
Total current assets	2,999	1,712
Property, plant and equipment, at cost		
Pipelines	17,561	16,750
Natural gas and oil properties, at full cost	19,479	19,048
Other	323	530
	37,363	36,328
Less accumulated depreciation, depletion and amortization	17,595	16,974
Total property, plant and equipment, net	19,768	19,354
Other assets		
Investments in unconsolidated affiliates	1,830	1,614
Assets from price risk management activities	240	302
Other	1,589	1,597
	3,659	3,513
Total assets	$ 26,426	$ 24,579

See accompanying notes.

Table of Contents

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

	September 30, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 447	$ 460
Affiliates	7	5
Other	573	502
Current maturities of long-term financing obligations	1,079	331
Liabilities from price risk management activities	256	267
Accrued interest	232	195
Other	786	653
Total current liabilities	3,380	2,413
Long-term financing obligations, less current maturities	12,258	12,483
Other		
Liabilities from price risk management activities	833	931
Deferred income taxes	1,660	1,157
Other	1,621	1,750
	4,114	3,838
Commitments and contingencies (Note 8)		
Minority interest	559	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 712,119,118 shares in 2008 and 709,192,605 shares in 2007	2,136	2,128
Additional paid-in capital	4,649	4,699
Accumulated deficit	(975)	(1,834)
Accumulated other comprehensive loss	(167)	(272)
Treasury stock (at cost); 13,900,806 shares in 2008 and 8,656,095 shares in 2007	(278)	(191)
Total stockholders equity	6,115	5,280

Total liabilities and stockholders equity	$	26,426	$	24,579

See accompanying notes.

3

Table of Contents

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Cash flows from operating activities		
Net income	$ 855	$ 950
Less income from discontinued operations, net of income taxes		674
Income from continuing operations	855	276
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	903	850
Deferred income taxes	470	127
Earnings from unconsolidated affiliates, adjusted for cash distributions	(12)	81
Loss on debt extinguishment		287
Other non-cash income items	47	(52)
Asset and liability changes	(212)	(76)
Cash provided by continuing activities	2,051	1,493
Cash used in discontinued activities		(31)
Net cash provided by operating activities	2,051	1,462
Cash flows from investing activities		
Capital expenditures	(1,905)	(1,796)
Cash paid for acquisitions	(362)	(1,182)
Net proceeds from the sale of assets and investments	671	82
Net change in restricted cash	35	33
Other	44	17
Cash used in continuing activities	(1,517)	(2,846)
Cash provided by discontinued activities		3,660
Net cash provided by (used in) investing activities	(1,517)	814
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	4,083	5,253
Payments to retire long-term debt and other financing obligations	(3,556)	(7,286)
Net proceeds from issuance of subsidiary equity	15	
Payments to minority interest holders	(20)	
Dividends paid	(113)	(112)
Repurchase of shares	(77)	
Contributions from discontinued operations		3,346

Other	9	4
Cash provided by continuing activities	341	1,205
Cash used in discontinued activities		(3,629)
Net cash provided by (used in) financing activities	341	(2,424)
Change in cash and cash equivalents	875	(148)
Cash and cash equivalents		
Beginning of period	285	537
End of period	$ 1,160	$ 389

See accompanying notes.

Table of Contents

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 445	$ 155	$ 855	$ 950
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 $2 and $7 in 2008 and $3 and $10 in 2007)	3	5	13	18
Cash flow hedging activities:				
Unrealized mark-to-market gains arising during period (net of income taxes of $227 and $5 in 2008 and $22 and $3 in 2007)	405	39	10	6
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $24 and $46 in 2008 and $22 and $46 in 2007)	42	(38)	81	(78)
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)
Other comprehensive income (loss)	450	6	102	(66)
Comprehensive income	$ 895	$ 161	$ 957	$ 884

See accompanying notes.

Table of Contents

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles. You should read this Quarterly Report on Form 10-Q along with our 2007 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2008, and for the quarters and nine months ended September 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.

Table of Contents

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 approximately $14 million as of September 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. During the nine months ended September 30, 2008, we acquired additional interests in onshore domestic natural gas and oil properties for approximately $61 million. During 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas for approximately $254 million and also acquired Peoples Energy Production Company (Peoples) for $879 million. Peoples was an exploration and production company with natural gas and oil properties located primarily in the ArkLaTex, Texas Gulf Coast and Mississippi areas and in the San Juan and Arkoma Basins.

Divestitures

During the nine months ended September 30, 2008, we sold natural gas and oil properties primarily in the Gulf of Mexico and Texas Gulf Coast regions for net cash proceeds of approximately $649 million. We also sold two power investments located in Central America and Asia for net cash proceeds of approximately $16 million. During the nine months ended September 30, 2007, we received approximately $82 million of proceeds from the sales of assets and investments, primarily related to the sale of a pipeline lateral and our investment in the New York Mercantile Exchange (NYMEX).

Discontinued Operations. Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals to be disposed of by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these 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.

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 and recorded a gain on the sale of $648 million, net of taxes of $354 million. Included in the net assets of these discontinued operations as of the date of 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)
Nine Months Ended September 30, 2007	
Revenues	$ 101
Costs and expenses	(43)
Other expense[1]	(7)
Interest and debt expense	(10)
Income taxes	(15)
Income from operations	26
Gain on sale, net of income taxes of $354 million	648

Net income from discontinued operations	$	674

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

7

Table of Contents

3. Income Taxes

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions, except for rates)			
Income taxes	$215	$100	$450	$151
Effective tax rate	33%	39%	34%	35%

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. Our effective tax rate may be affected by items such as dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the effect of state income taxes (net of federal income tax effects), and the effect of foreign income which can be taxed at different rates.

During the nine months ended September 30, 2008 and 2007, our effective tax rate on continuing operations was relatively consistent with the statutory rate and the customary relationship between our pretax accounting income and income tax expense. However, our effective tax rate for the quarter ended September 30, 2008, was lower than the statutory rate due primarily to the foreign tax impact of fluctuations in exchange rates while our effective tax rate for the quarter ended September 30, 2007, was higher than the statutory rate due primarily to impairments on foreign investments for which there were no corresponding income tax benefits.

We file income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. For years in which our returns are still subject to review, our unrecognized tax benefits (liabilities for uncertain tax matters) could increase or decrease our income tax expense and, in turn, effective income tax rates as these open years are closed, although we are unable to estimate the range of potential impacts the resolution of any contested matters could have on our financial statements. 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.

As of January 1, 2008 and September 30, 2008, we had unrecognized tax benefits of $157 million and $126 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 $122 million as of September 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.

Table of Contents

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 September 30				
Income from continuing operations	$ 445	$ 445	$ 155	$ 155
Convertible preferred stock dividends	(9)		(9)	
Interest on trust preferred securities		3		
Income from continuing operations available to common stockholders	436	448	146	155
Discontinued operations, net of income taxes				
Net income available to common stockholders.	$ 436	$ 448	$ 146	$ 155
Weighted average common shares outstanding	696	696	696	696
Effect of dilutive securities:				
Options and restricted stock		4		5
Trust preferred securities		8		
Convertible preferred stock		58		58
Weighted average common shares outstanding and dilutive securities	696	766	696	759
Earnings per common share:				
Income from continuing operations	$ 0.63	$ 0.58	$ 0.21	$ 0.20
Discontinued operations, net of income taxes				
Net income	$ 0.63	$ 0.58	$ 0.21	$ 0.20

	2008		2007	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Nine Months Ended September 30				
Income from continuing operations	$ 855	$ 855	$ 276	$ 276
Convertible preferred stock dividends	(28)		(28)	(28)
Interest on trust preferred securities		8		
Income from continuing operations available to common stockholders	827	863	248	248
Discontinued operations, net of income taxes			674	674
Net income available to common stockholders.	$ 827	$ 863	$ 922	$ 922

Weighted average common shares outstanding	697	697	695	695
Effect of dilutive securities:				
Options and restricted stock		4		4
Trust preferred securities		8		
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	697	767	695	699
Earnings per common share:				
Income from continuing operations	$ 1.19	$ 1.12	$ 0.36	$ 0.35
Discontinued operations, net of income taxes			0.97	0.96
Net income	$ 1.19	$ 1.12	$ 1.33	$ 1.31

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

Table of Contents

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 primarily based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets). 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 third party pricing sources and our creditworthiness or that of our counterparties.

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 obtain pricing data from third party pricing sources, adjust this data based on the liquidity of the underlying forward markets over the contractual terms and use the adjusted pricing data 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; (iii) the limited availability of forward pricing information in markets where there is a lack of viable participants, such as in the Pennsylvania-New Jersey-Maryland (PJM) forward power market and the forward market for ammonia; and (iv) our creditworthiness or that of our counterparties. 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.

Table of Contents

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

	Level 1	Level 2	Level 3	Total
Assets				
Marketable securities invested in non-qualified compensation plans	$ 21	$	$	$ 21
Production-related natural gas and oil derivatives		324		324
Other natural gas derivatives		89	31	120
Power-related derivatives			99	99
Foreign currency swaps			85	85
Total assets	$ 21	$ 413	$ 215	$ 649

	Level 1	Level 2	Level 3	Total
Liabilities				
Production-related natural gas and oil derivatives	$	$ (84)	$	$ (84)
Other natural gas derivatives		(217)	(193)	(410)
Power-related derivatives			(586)	(586)
Interest rate swaps		(9)		(9)
Other			(72)	(72)
Total liabilities		(310)	(851)	(1,161)
Total	$ 21	$ 103	$ (636)	$ (512)

On certain derivative contracts recorded as assets we are exposed to the risk that our counterparties may not be able to perform or post the required collateral, if any, with us. We have assessed this counterparty risk in light of the collateral our counterparties have posted with us and the recent instability in the credit markets. Based on this assessment, we have determined that our exposure is primarily related to our production-related derivatives and foreign currency swaps and is limited to seven financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

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

	Balance at Beginning of Period	Change in fair value reflected in operating revenues(1)	Change in fair value reflected in operating expenses(2)	Change in fair value reflected in long-term financing obligations(3)	Settlements, Net	Balance at End of Period
Quarter Ended September 30, 2008						
Assets	$ 342	$ (63)	$	$ (46)	$ (18)	$ 215
Liabilities	(1,012)	116	(8)		53	(851)
Total	$ (670)	$ 53	$ (8)	$ (46)	$ 35	$ (636)

Nine Months Ended September 30, 2008

Assets	$ 250	$ 25	$	$ (24)	$ (36)	$ 215
Liabilities	(839)	(108)	(39)		135	(851)
Total	$ (589)	$ (83)	$ (39)	$ (24)	$ 99	$ (636)

(1) Includes approximately $49 million of net gains and $79 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2008.

(2) Includes approximately $8 million and $35 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2008.

(3) Includes approximately $46 million and $24 million of net losses that had not been realized through settlements for the quarter and nine months ended

September 30,
2008.

Table of Contents

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.

	September 30, 2008	December 31, 2007
	(In millions)	
Net assets (liabilities):		
Derivatives designated as accounting hedges	$ 126	$ (23)
Other commodity-based derivative contracts	(663)	(869)
Total commodity-based derivatives	(537)	(892)
Interest rate and foreign currency derivatives	76	109
Net liabilities from price risk management activities[(1)]	$ (461)	$ (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

	September 30, 2008	December 31, 2007
	(In millions)	
Current maturities of long-term financing obligations	$ 1,079	$ 331
Long-term financing obligations	12,258	12,483
Total	$ 13,337	$ 12,814

Long Term Financing Obligations. On September 30, 2008, El Paso Pipeline Partners, L.P. (EPB), our master limited partnership (MLP), issued $175 million of private placement debt as part of the MLP s purchase of incremental interests in Colorado Interstate Gas (CIG) and Southern Natural Gas (SNG). The EPB borrowings are due 2011 through 2013, are non-recourse to El Paso and have an average annual rate of 7.8 percent. During the second quarter of 2008, we repurchased $289 million of subsidiary debt obligations and issued $600 million of 7.25% unsecured senior notes that mature in June 2018.

Credit Facilities. As of September 30, 2008, we had available capacity under various credit agreements (excluding that under EPB s $750 million revolving credit facility) of approximately $0.7 billion as follows:

Facility	Credit Facility	Available Capacity
El Paso revolving credit agreement	$1.5 billion	$0.6 billion
El Paso Exploration and Production (EPEP) revolving credit facility	$1.0 billion	$0.1 billion
Unsecured credit facilities	$1.0 billion	___

As of September 30, 2008, the total amount outstanding under EPB s $750 million revolving credit facility was approximately $586 million. The EPB borrowings are not recourse to El Paso and the facility is solely available for use by EPB and its subsidiaries.

12

As part of our determination of available capacity under our credit agreements, we completed an assessment of the available lenders under our credit facilities. Based on our assessment as of September 30, 2008, our available capacity noted above was reduced to reflect the potential exposure to a loss of available capacity of approximately $25 million on El Paso s $1.5 billion revolving credit facility, approximately $2 million on EPEP s revolving credit facility and approximately $15 million under the EPB facility. This assessment is based upon the fact that one of our lenders has failed to fund previous requests under these facilities and has filed for bankruptcy.

Restrictive Covenants. Under our credit agreements, our most restrictive debt covenants (see our 2007 Annual Report on Form 10-K) relate to maintaining certain financial coverage ratios. As of September 30, 2008 we are in compliance with these coverage ratios which include among other ratios, a ratio of Debt to Consolidated EBITDA, each as defined in our $1.5 billion credit agreement. For the last 12 months through September 30, 2008, our ratio of Debt to Consolidated EBITDA was approximately 3.4 to 1 compared with the requirement that our ratio of Debt to Consolidated EBITDA shall not exceed 5.25 to 1 until maturity.

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. In the third quarter, we closed a new letter of credit facility with a bank to support our purchase commitments for pipe related to the Ruby Pipeline project. Through September 30, 2008 we issued two letters of credit under this facility that total approximately $450 million. Of our outstanding letters of credit under this facility, we pay 0.85% annually on approximately $180 million maturing in one year and 1.00% annually on approximately $270 million maturing in two years. As of September 30, 2008, we had total outstanding letters of credit issued under all facilities of approximately $1.8 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 reached an agreement in principle to settle this matter and 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 s age discrimination, backloading and notice provisions 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, but in October 2008, the Tennessee Court of Appeals reversed the dismissal, remanding the matter to trial court. 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. We reached an agreement in principle to settle the Western States and Ever-Bloom cases and have established accruals for those cases which we believe are adequate. Settlement documents are being drafted. Our costs and legal exposure related to the remaining 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, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies. They have sought different remedies, including remediation of the groundwater, future remedial activities, damages, punitive damages and attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. Several cases were later remanded. We recently settled 59 of these lawsuits, with our payments being made in October 2008. These settlements are covered by insurance and substantially all of the settlement amounts will be funded by our insurers. Following such settlements, there are 24 lawsuits that remain. While the damages claimed in the 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. Other than 3 recently filed actions, 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 September 30, 2008, we had approximately $111 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 and rights of way in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS.

Greenhouse Gas Emissions. Currently, various legislative and regulatory measures to address greenhouse gas (GHG) emissions are in various phases of discussion or implementation. Various federal legislative proposals have been made over the last several years. The Environmental Protection Agency (EPA) is considering a

Table of Contents

rulemaking regarding potential regulation of GHG emissions from stationary and mobile sources under the Clean Air Act. Legislation and regulation are also in various stages of proposal, enactment, and implementation in many states throughout the United States. If enacted as proposed, the federal and state legislative and regulatory proposals would impact our operations and financial results. However, until enacted, it is not possible to determine the exact impact that these future measures might have on our operations and financial results. Additionally, various governmental entities and environmental groups have filed lawsuits seeking to force the federal government to regulate GHG emissions and individual companies to reduce GHG emissions from their operations. These and other suits may result in decisions by state courts, federal agencies, and other governing bodies that could impact our operations and ability to obtain certifications and permits to construct future projects.

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. Negotiations on the remaining terms and conditions are continuing. Based on the preliminary agreement, EPNG made payments to the Navajo Nation covering the period from January 2007 through October 2008. EPNG made a second payment to the Navajo Nation in October 2008 covering a twelve-month period through October 2009. 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.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2008, we had accrued approximately $224 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 $217 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $7 million for related environmental legal costs. Of the $224 million accrual, $19 million was reserved for facilities we currently operate and $205 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 $224 million to approximately $417 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 ($210 million to $403 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. Our recorded liabilities reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	September 30, 2008	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 19	$ 26
Non-operating	183	346
Superfund	22	45
Total	$ 224	$ 417

16

Table of Contents

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

Balance as of January 1, 2008	$ 260
Additions/adjustments for remediation activities	(6)
Payments for remediation activities	(30)
Balance as of September 30, 2008	$ 224

For the remainder of 2008, we estimate that our total remediation expenditures will be approximately $21 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 33 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 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 $820 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 September 30, 2008, we have recorded obligations of $79 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.

Purchase Obligations. During 2008, we entered into contracts to purchase pipe primarily associated with the Ruby Pipeline project and TGP s 300 Line expansion which are anticipated to be placed in service between 2010 and 2011. Our estimated obligations under these agreements are approximately $80 million for the remainder of 2008, $660 million in 2009 and $143 million in 2010.

Asset Retirement Obligations. Our asset retirement liabilities as of September 30, 2008 reflect a reduction of approximately $109 million related to the sale of a portion of our natural gas and oil properties in the Gulf of Mexico and Texas Gulf Coast regions and an increase of approximately $52 million resulting from the third quarter of 2008 impacts of Hurricanes Ike and Gustav on our exploration and production and pipeline assets.

9. Retirement Benefits

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

	Quarters Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007	2008	2007	2008	2007
	(In millions)							
Service cost	$ 4	$ 4	$	$	$ 11	$ 13	$	$
Interest cost	30	30	10	6	90	90	27	19
Expected return on plan assets	(47)	(45)	(4)	(4)	(140)	(136)	(12)	(12)
Amortization of net actuarial loss (gain)	6	11	(1)		18	32	(3)	
Amortization of prior service cost(1)	(1)	(1)		1	(2)	(2)	(1)	
Net benefit cost (income)	$ (8)	$ (1)	$ 5	$ 3	$ (23)	$ (3)	$ 11	$ 7

(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, and thus 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.

During the fourth quarter of 2008, we expect to contribute an additional $21 million to our other postretirement benefit plans.

As a result of the general decline in the markets for debt and equity securities, the funded status of our pension and other postretirement benefit plans declined significantly during the third quarter of 2008. Although we do not currently anticipate having to make any significant contributions to our pension plans in 2009 as a result of the decrease in funded status, if the fair value of the investments in our pension plans continues to be negatively impacted, this decline could result in a significant decrease in our postretirement benefit asset and in other comprehensive income in the fourth quarter of 2008 when the plans assets and obligations are remeasured.

10. Stockholders Equity

Share Repurchase Program. During 2008, the Board approved a $300 million share repurchase program and we repurchased approximately $77 million in common stock under the program through September 30, 2008.

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

	Common Stock	Convertible Preferred Stock
Amount paid through September 30, 2008	$ 85	$ 28
Amount paid in October 2008	$ 34	$ 9
Dividends declared subsequent to September 30, 2008		
Date of declaration	October 23, 2008	October 23, 2008
Payable to shareholders on record	December 5, 2008	December 15, 2008
Date payable	January 2, 2009	January 2, 2009

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 fourth quarter 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. Through October 2008, our Board of Directors declared dividends for our common shareholders of $0.04 per share in February and March and $0.05 per share in July and October.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock provide for the conversion ratio on our preferred stock to increase when we pay quarterly dividends to our common stockholders in excess of $0.04 per share, as we did in October 2008 and will do in January 2009. The terms of these preferred shares also 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 we are unable to comply with our fixed charge coverage ratio, our ability to pay additional dividends would be restricted.

11. Business Segment Information

As of September 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 September 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 another 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.

19

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.

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 September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions)			
Segment EBIT	$ 886	$ 432	$ 1,905	$ 1,432
Corporate and other	(5)	51	75	(263)
Interest and debt expense	(221)	(228)	(675)	(742)
Income taxes	(215)	(100)	(450)	(151)
Income from continuing operations	$ 445	$ 155	$ 855	$ 276

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

	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
	(In millions)					
Quarters Ended September 30, 2008						
Revenue from external customers	$615	$ 528[2]	$ 450	$	$ 5	$1,598
Intersegment revenue	13	353[2]	(361)		(5)	
Operation and maintenance	223	90	7	4	5	329
Depreciation, depletion and amortization	97	191			4	292
Earnings from unconsolidated affiliates	28	10		12	2	52
EBIT	278	532	82	(6)	(5)	881
2007						
Revenue from external customers	$572	$ 290[2]	$ 284	$	$ 20	$1,166
Intersegment revenue	14	285[2]	(293)		(6)	

Operation and maintenance	199	106	4	5	34	348
Depreciation, depletion and amortization	94	194		1	4	293
Earnings (losses) from unconsolidated affiliates	28	2		(36)(3)		(6)
EBIT	275	232	(8)	(67)(3)	51(4)	483

(1) Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. During the quarter ended September 30, 2008, we recorded an intersegment revenue elimination of $5 million and during the quarter ended September 30, 2007, we recorded an intersegment revenue elimination of $6 million.

(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) Includes a loss associated with our equity investment in and note receivable from the Porto Velho project, which is further discussed in Note 12.

(4) Includes a $77 million gain associated with the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business.

	Segments					
		Exploration and			Corporate and	
	Pipelines	Production	Marketing	Power	Other[1]	Total
			(In millions)			
Nine Months Ended September 30, 2008						
Revenue from external customers	$1,954	$ 856(2)	$ 1,194	$	$ 16	$4,020
Intersegment revenue	40	1,283(2)	(1,308)		(15)	
Operation and maintenance	623	303	17	13	(74)	882
Depreciation, depletion and amortization	295	600			8	903
Earnings from unconsolidated affiliates	74	36		28	3	141
EBIT	954	1,078	(131)	4	75	1,980
2007						
Revenue from external customers	$1,803	$ 778(2)	$ 744	$	$ 61	$3,386
Intersegment revenue	41	877(2)	(904)		(14)	
Operation and maintenance	541	326	7	16	88	978
Depreciation, depletion and amortization	279	553	2	1	15	850
Earnings (losses) from unconsolidated affiliates	83	4		(12)(3)		75
EBIT	957	646	(138)	(33)(3)	(263)(4)	1,169

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

During the nine months ended September 30, 2008, we recorded an intersegment revenue elimination of $16 million, and for the nine months ended September 20, 2007, we recorded an intersegment revenue elimination of $15 million.

(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) Includes a loss associated with our equity investment in and note receivable from the Porto Velho project, which is

further discussed in Note 12.

(4) Debt and treasury management activities, which are part of Corporate and Other, included debt extinguishment costs of $287 million for the nine months ended September 30, 2007, $86 million of which is related to refinancing of EPEP s $1.2 billion notes. This amount also includes a $77 million gain associated with the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business.

Total assets by segment are presented below:

	September 30, 2008	**December 31, 2007**
	(In millions)	
Pipelines	$ 14,834	$ 13,939
Exploration and Production	8,236	8,029
Marketing	479	537
Power	467	531
Total segment assets	24,016	23,036
Corporate and Other	2,410	1,543

Total consolidated assets	$ 26,426	$ 24,579

Table of Contents

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.

			Earnings (Losses) from Unconsolidated Affiliates			
	Investment		Quarters Ended		Nine Months Ended	
Net Investment and Earnings (Losses)	September 30, 2008	December 31, 2007	September 30, 2008	September 30, 2007	September 30, 2008	September 30, 2007
	(In millions)		(In millions)			
Four Star [1]	$ 659	$ 698	$ 10	$ 2	$ 36	$ 4
Citrus	551	576	20	21	52	65
Gulf LNG[2]	295					
Bolivia to Brazil Pipeline	111	105	9	3	15	8
Gasoductos de Chihuahua	167	146	8	6	21	16
Manaus/Rio Negro[3]		56		(7)		2
Porto Velho[4]	(63)	(60)		(31)		(24)
Asian and Central American Investments [5]	17	26			6	(1)
Argentina to Chile Pipeline	26	21	2	1	5	4
Other	67	46	3	(1)	6	1
Total	$ 1,830	$ 1,614	$ 52	$ (6)	$ 141	$ 75

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $13 million and $10 million for the quarters ended September 30, 2008 and 2007 and $40 million and $37 million for the nine months ended September 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) During the third quarter of 2007, we recorded a $32 million impairment of our investment in Porto Velho and a $25 million impairment of our note

receivable from the project based on ongoing developments in the Brazilian power markets. As of September 30, 2008 and December 31, 2007, we had outstanding advances and receivables of $274 million and $335 million related to our investment in Porto Velho, not included above.

(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.

	Quarters Ended September 30,		Nine Months Ended September 30,	
Summarized Financial Information	**2008**	**2007**	**2008**	**2007**
	(In millions)			
Operating results data:				
Operating revenues	$196	$222	$576	$638
Operating expenses	81	132	258	375
Income from continuing operations	64	51	186	164
Net income(1)	64	51	186	164

(1) Includes net income of less than $1 million for the quarters ended September 30, 2008 and 2007,

and $1 million and $9 million for the nine months ended September 30, 2008 and 2007, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

We received cash distributions and dividends from our unconsolidated affiliates of $48 million and $35 million for the quarters ended September 30, 2008 and 2007 and $129 million and $173 million for the nine months ended September 30, 2008 and 2007. Included in these amounts are returns of capital of less than $1 million and $17 million for the quarter and nine months ended September 30, 2007. Our revenues and charges with unconsolidated affiliates were not material during the quarter and nine months ended September 30, 2008.

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 $211 million as of September 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. During the second quarter 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. There are additional net claims of $30 million, which primarily relate to retroactive currency indexation adjustments claimed by the state-owned utility through 2007, which we believe 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. Any adverse developments in our negotiations with our partner or the utility, or in the ability of our partner to obtain financing for the sale, could impact our ability to sell our investment in the project and could require us to record losses on our investment in the future.

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. The Brazilian national power grid operator has 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, which we estimate could be in late 2009. 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 $64 million of our investment during the nine months ended September 30, 2008 and an additional $7 million in October 2008 through payments we received from the project. In conjunction with the negotiations on the sale of our investment, 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 September 30, 2008, we have approximately $60 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 $58 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 (and the parent of the purchaser) about their claims. 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, and 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 September 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 $25 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 September 30, 2008, our total investment and guarantees related to this pipeline project was approximately $123 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. During the second quarter of 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 September 30, 2008, our total investment in this pipeline project was approximately $26 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. We continue to discuss the potential sale of our interest in the Argentina to Chile pipeline to one of our partners.

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 nine months of 2008, our pipeline and exploration and production operations continued to provide a strong base of earnings and cash flow. In our pipeline business, our operating performance remained strong and we continue to make progress on our $8 billion backlog of committed expansion projects. In our exploration and production business, we experienced continued success benefiting from a favorable commodity price environment. Our production volumes, however, were adversely impacted during the third quarter as a result of production shut in by Hurricanes Ike and Gustav. In our Marketing segment, volatility in locational power prices in the PJM power market and changes in commodity prices impacting our production-related derivative contracts continued to impact our financial results. For the remainder of 2008, we expect the earnings and cash flows in our exploration and production business to be impacted by the decline in commodity prices and continued effects on production volumes caused by the recent hurricanes.

Outlook. Current global financial markets are extremely volatile. The U.S. and foreign governments have recently enacted emergency financial packages designed to restore confidence and liquidity in the global financial markets. However, it is uncertain whether such measures will be successful and, if successful, when and to what degree the positive effects will be reflected in the financial markets. As a result, we currently expect that this volatility in the global financial markets will likely impact our operations in 2009 in several ways. First, it may restrict our access to financial markets to fund our growth projects. When we do access the financial markets, it will likely be at a higher cost than that available prior to the current period of volatility. Second, the current financial crisis may impact the general conditions in our industry, including impacts on the demand for natural gas and future commodity prices. Third, it may impact the financial strength of our counterparties, including our lenders, trading counterparties, customers, joint interest partners, vendors and suppliers.

In light of these risks and potential impacts on our operations, we have implemented certain actions and anticipate implementing further actions for the remainder of 2008 and 2009 in response to the current volatility in the financial markets. These actions reflect the following:

- We have made adjustments to our capital expenditures for the remainder of 2008. In particular, we have reduced our anticipated capital expenditures for 2008 by $0.3 billion, with our anticipated total year expenditures equal to approximately $3.5 billion.

- Our current estimate of our 2009 capital program is approximately $3 billion, with $1.7 billion of capital being spent in our pipeline business and $1.3 billion in our exploration and production business. Production volumes in 2009 are estimated to be approximately flat with 2008 volumes. Our $1.7 billion of planned pipeline capital reflects equity partnering on one or more of our expansion projects. We also expect to sell several non-core assets generating cash proceeds of approximately $150 million by mid-2009.

- Based upon our current and projected liquidity following our debt maturities that become due in May 2009, we do not currently contemplate having to access the capital markets until the second half of 2009. Although there are many different factors that will determine our actual capital and liquidity requirements in the future, we currently expect that we would seek to raise between $500 million to $800 million of capital in the second half of 2009. However, we will be opportunistic in accessing the capital markets prior to that time.

- To the extent the financial markets remain restricted into the second half of 2009, any of the asset sales or partnering opportunities set forth above are delayed or cannot be completed or there is a further decline in commodity prices, we would review other alternatives, including additional reductions in our discretionary capital program, secured financing arrangements, seeking additional partners for one or more of our growth projects and the sale of additional non-core assets.

25

With our debt capital structure of 79% fixed interest rates and 21% floating interest rates, we believe we have substantially mitigated our exposure to market changes in interest rates on interest costs.

With regard to the risk of loss of demand due to potential recessionary pressures, approximately three-fourths of our pipeline revenues are collected in the form of demand or reservation charges. As a result, near-term declines in demand for natural gas or natural gas prices do not materially impact our pipeline revenues. With regard to the risk of reductions in commodity prices, we have hedges in place for 2009 that provide an average floor price of $9.02 per MMBtu for 176 TBtu and 3.43 million barrels of oil hedged at an average price of $109.93 per barrel. As a result, the risk of reductions in commodity prices is greatly mitigated for 2009. For example, based on our current positions, a change of $1 per MMBtu in the price of natural gas would impact our anticipated annual operating cash flow by approximately $50 million and a change of $10 per barrel in the price of oil would impact our anticipated annual operating cash flow by approximately $20 million. Additionally, our revolving credit facility at our exploration and production subsidiary has a borrowing base that can be reduced in the event of lower oil or natural gas prices. However, we currently have other unsecured exploration and production properties and reserves that we could pledge to maintain the current amounts available under this revolving credit facility.

With regard to counterparty risk, we continually monitor the financial situation of our major lenders, trading counterparties, customers, joint interest partners, vendors and suppliers, and enforce our contractual rights with regard to providing collateral or credit.

- As part of our determination of available capacity under our credit agreements, we completed an assessment of our available lenders under these facilities, which is a diverse group. Based on our assessment, we have determined the potential exposure to a loss of available capacity to be approximately $25 million from El Paso s $1.5 billion revolving credit facility , approximately $2 million from EPEP s $1.0 billion revolving credit facility, and approximately $15 million under the EPB facility. This assessment is based upon the fact that one of our lenders has failed to fund previous requests under these facilities and has filed for bankruptcy.

- We have also reviewed the risk of consolidation of lending institutions on our current revolving credit facility. Since our revolving credit facilities do not expire until 2012, we believe this consolidation risk will not be a near term issue and will be an issue that we address over the next several years.

- We conduct similar reviews of the credit risks of our trading counterparties and our material customers, joint interest owners, suppliers and vendors. Certain of our contractual arrangements with such parties include requirements to provide letters of credit, performance bonds or other assurances of performance to mitigate, in part, against the risk of non-performance by such parties. However, our natural gas and oil hedges executed at EPEP do not contractually require the posting of margin.

Our plans are designed to achieve two broad objectives. First, our actions are designed to address the potential impacts of the current volatility in the global financial markets and to maintain sufficient liquidity to meet our 2009 debt maturities and to fund our reduced capital program in 2009. Second, despite the reductions in our capital program for 2009, our actions are designed to retain our long term growth potential, including our committed pipeline project backlog and our core domestic and international drilling programs, as well as resource inventory positions. In light of the current volatility of the financial markets, however, it is possible additional adjustments to our plan and outlook will be required which could impact our financial and operating performance. A prolonged period of restricted access to the financial markets could also impact our long-term growth potential.

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.

Table of Contents

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 September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions)			
Segment				
Pipelines	$ 278	$ 275	$ 954	$ 957
Exploration and Production	532	232	1,078	646
Marketing	82	(8)	(131)	(138)
Power	(6)	(67)	4	(33)
Segment EBIT	886	432	1,905	1,432
Corporate and other	(5)	51	75	(263)
Consolidated EBIT	881	483	1,980	1,169
Interest and debt expense	(221)	(228)	(675)	(742)
Income taxes	(215)	(100)	(450)	(151)
Income from continuing operations	445	155	855	276
Discontinued operations, net of income taxes				674
Net income	$ 445	$ 155	$ 855	$ 950

Table of Contents

Pipelines Segment

Overview and Operating Results. Our Pipeline Segment s EBIT for the three months ended September 30, 2008 was $278 million compared with $275 million for the same quarter in 2007. EBIT before minority interest associated with El Paso Pipeline Partners, which completed its initial public offering in November 2007, was $285 million. In the third quarter of 2008, our EBIT also includes a $12 million unfavorable impact related to lost natural gas and higher operations and maintenance costs due to facility damage caused by Hurricanes Ike and Gustav. We continue to assess the damages resulting from the hurricanes and the corresponding impact on estimated costs to repair and abandon impacted facilities. We anticipate incurring additional costs in the fourth quarter and into 2009. During the third quarter of 2008, EBIT was favorably impacted by higher reservation revenues due to additional capacity sold on our pipeline systems and several expansion projects that went into service in 2007 and 2008. Offsetting the favorable impact were higher operating costs primarily due to increased labor costs to support growth and customer activities as well as additional maintenance work required on several of our pipeline systems. Below are the operating results for our Pipelines segment as well as an expanded discussion of factors impacting EBIT, or that could potentially impact EBIT in future periods.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions, except volume amounts)			
Operating revenues	$ 628	$ 586	$ 1,994	$ 1,844
Operating expenses	(387)	(352)	(1,133)	(1,010)
Operating income	241	234	861	834
Other income	44	41	117	123
EBIT before minority interest	285	275	978	957
Minority interest	(7)		(24)	
EBIT	$ 278	$ 275	$ 954	$ 957
Throughput volumes (BBtu/d)[(1)]	18,905	18,512	18,736	17,909

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

Variance Analysis and Discussion

	Quarter Ended September 30, 2008				Nine Months Ended September 30, 2008			
	Variance				Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable)							

				(In millions)				
Expansions	$ 14	$ (6)	$ 7	$ 15	$ 58	$ (20)	$ 8	$ 46
Reservation and usage revenues	18			18	37			37
Gas not used in operations and revaluations	15	(11)		4	34	(23)		11
Bankruptcy settlements	(1)			(1)	27	1		28
Hurricanes	(7)	(5)		(12)	(7)	(5)		(12)
Operating and general and administrative expenses		(19)		(19)		(47)		(47)
Gain/loss on long-lived assets						(26)		(26)
Equity earnings from Citrus			(2)	(2)			(13)	(13)
Minority interest			(7)	(7)			(24)	(24)
Other[1]	3	6	(2)	7	1	(3)	(1)	(3)
Total impact on EBIT	$ 42	$ (35)	$ (4)	$ 3	$ 150	$ (123)	$ (30)	$ (3)

(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, Cheyenne Plains compression expansion project in August 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.

Table of Contents

We have continued to make progress on our $8 billion backlog of expansion projects. 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 nine months ended September 30, 2008, we have spent approximately $0.8 billion on these projects and currently anticipate spending $0.4 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 300 Line Expansion. In August 2008, we announced the expansion of TGP s 300 Line pipeline. The estimated total capital cost for this expansion project is approximately $750 million with anticipated in-service dates in the fourth quarter of 2010 for Phase I and in the fourth quarter of 2011 for Phase II.

CIG Raton 2010 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 with an estimated in-service date in the second quarter of 2010. The tentative FERC filing date for this project is January 2009.

WIC Expansions. We announced the expansions of the WIC system in July 2008. Due to increased shipper commitments, WIC recently expanded the scope of this project to add a second compressor unit on the Kanda Lateral, which increased its capital cost from $55 million to $71 million. These expansions 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 November 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. Phase I of the project was placed in service in September 2008. Phase II is anticipated to be placed in service in June 2011.

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.

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 300 Line expansion project on a fixed price basis. See Liquidity and Capital Resources.

29

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

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, increased reservation charges for capacity on our EPNG 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 nine months ended September 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 designed to recover all cost impacts, or flow through to shippers any revenue impacts, of certain fuel imbalance revaluations and related gas balance items and should reduce earnings volatility resulting from these items over time. In September 2008, the FERC issued an order accepting certain tariff changes related to CIG to be effective October 1, 2008, subject to refund and the outcome of a technical conference which is scheduled to be in November 2008. As a result of this order, CIG recorded an unfavorable fuel cost and revenue tracker reserve adjustment in the third quarter of 2008 following the receipt of the FERC order. We do not believe this will have a material impact on our financial statements.

Bankruptcy Settlements. During the first nine months of 2008, our revenue increased by $33 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 also recorded income of approximately $8 million and $2 million as a result of settlements received from the Enron Corporation bankruptcy. In second quarter of 2007, we received $10 million to settle our bankruptcy claim against US Gen New England, Inc.

Hurricanes. During the third quarter of 2008, we incurred damage to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Ike and Gustav. Our EBIT was unfavorably impacted by these hurricanes due to gas loss from various damaged pipelines, lower volume of gas not used in operations, lower usage revenue and repair costs that will not be recoverable from insurance. See Liquidity and Capital Resources for a further discussion of the hurricanes.

Operating and General and Administrative Expenses. For the quarter and nine months ended September 30, 2008, our operating and general and administrative expenses were higher than the same periods in 2007 primarily due to increased labor costs to support our growth and customer activities and additional maintenance work required on several of our pipeline systems.

Gain/Loss on Long-Lived Assets. During the nine months ended September 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 nine months ended September 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 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 nine months ended September 30, 2008, we recorded approximately $7 million and $24 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.

Under the terms of SNG s last rate settlement, SNG is obligated to file proposed new rates to be effective no later than October 1, 2010. SNG anticipates filing a new rate case no later than March 2009 with revised rates expected to become effective September 1, 2009.

Table of Contents

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance in this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. We also enter into financial derivative contracts to mitigate against significant downward price movements which 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, adding assets and 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 regions, Central and Western. The Central region includes the Arklatex, Black Warrior and Mid-Continent areas while the Western region includes the Rockies and Raton Basin areas. Internationally, our 2008 capital is expected to be approximately 20 percent higher than 2007 and constitutes approximately 15 percent of our total capital program. Successful execution of our international program, primarily in Brazil, will require effective project management, partner relations and successful negotiations with regulatory agencies.

During 2008, we completed the sale of certain non-core properties for net cash proceeds of approximately $649 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. During 2008, we also acquired interests in domestic natural gas and oil properties for $61 million, primarily in the Western region. 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

Production. Our average daily production volumes for the nine months ended September 30, 2008 were 763 MMcfe/d (which does not include 74 MMcfe/d from our share of production volumes from our equity investment in Four Star). Average daily production volumes for the nine months ended September 30, 2008 associated with divested properties were 32 MMcfe/d. Below is an analysis of our production volumes by region for the periods ended September 30:

	Nine Months Ended September 30,	
	2008	**2007**
	(MMcfe/d)	
United States		
Central	238	220
Western	153	144
Texas Gulf Coast	227	199
Gulf of Mexico and south Louisiana	134	196
International		
Brazil	11	15
Total Consolidated	763	774

Four Star	74	67

Table of Contents

The increased 2008 production volumes in our 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 the impacts of Hurricanes Ike and Gustav during the third quarter of 2008, natural production declines and asset sales. Overall, Hurricanes Ike and Gustav impacted our production volumes during the quarter and nine months ended September 30, 2008 by approximately 41 MMcfe/d and 14 MMcfe/d and are expected to continue to have an impact on production volumes for the remainder of 2008 and into 2009. In Brazil, production volumes decreased primarily due to natural production declines.

2008 Drilling Results

Our drilling results during 2008 by region are as follows:

Central. We achieved a 100 percent success rate on 208 gross wells drilled.

Western. We achieved a 100 percent success rate on 93 gross wells drilled.

Texas Gulf Coast. We achieved a 94 percent success rate on 81 gross wells drilled.

Gulf of Mexico and south Louisiana. We achieved a 63 percent success rate on 8 gross wells drilled.

Brazil. Our drilling operations in Brazil are 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. In October 2008, IBAMA, the environmental regulatory agency in Brazil, issued to us the Terms of Reference for the Pinauna project, which represents the first major step in the environmental permitting process.

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. In the third quarter of 2008, we participated in drilling an exploratory well in the BM-CAL-5 block and the results are currently being evaluated. We plan to participate in drilling a second exploratory well in the BM-CAL-5 block which is scheduled for the first quarter of 2009.

Espirito Santo Basin- In 2007, we completed drilling and testing of 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 as well as other commercial agreements. The plan of development for this field, known as Camarupim Field, includes four wells that are projected by Petrobras to be completed and producing by the end of the first quarter of 2009. The price that we expect to receive for our natural gas production from the Camarupim Field will be indexed to a basket of international fuel oils. Additionally, in the third quarter of 2008, Petrobras began drilling an exploratory well on the ES-5 block in which we own a 35 percent working interest. We expect drilling operations on this well to be completed by the end of 2008. Petrobras plans to begin drilling a second exploratory well on this block before the end of the first quarter of 2009.

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 Egypt s Western Desert. We have selected our first well location and expect to commence drilling operations in the fourth quarter of 2008. During 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 as well as new opportunities around our block in the Western Desert.

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 nine months ended September 30, 2008, cash operating costs per unit increased to $1.94/Mcfe as compared to $1.89/Mcfe for the same period in 2007. The increase in 2008 is primarily due to higher production taxes resulting from higher natural gas and oil revenues and lower production volumes partially offset by lower lease operating expenses and lower general and administrative expenses. Lease operating expenses decreased in 2008 primarily due to the divestiture of higher cost properties in the Gulf of Mexico and south Louisiana region. General and administrative expenses decreased due primarily to the reversal of an accrual during the third quarter of 2008 as a result of a favorable ruling on a legal matter, which had a $0.30/Mcfe positive impact during the third quarter of 2008, while lost volumes and repair costs as a result of the hurricanes had a $0.12/Mcfe adverse effect on cash operating costs in the third quarter.

Capital Expenditures. Our total natural gas and oil capital expenditures were $1.2 billion for the nine months ended September 30, 2008, of which $1.1 billion 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 to range from approximately 745 MMcfe/d to 755 MMcfe/d, excluding approximately 70 MMcfe/d from our equity investment in Four Star. We have decreased our average daily production volume guidance from that previously disclosed primarily due to production shut in as a result of Hurricanes Ike and Gustav. Hurricane Ike caused minor damage to most of our 27 operated-platforms in the Gulf of Mexico and south Louisiana region while two structures in the Eugene Island area were heavily damaged. Prior to damages from Hurricane Ike, the two structures in the Eugene Island area produced approximately 15 MMcfe/d which remains shut in pending repairs. In addition, approximately 80 MMcfe/d of production remains shut in pending repairs to the High Island Offshore and Stingray gathering systems, which are owned and operated by third parties. The operators currently estimate these systems will be repaired and back in service by mid-December 2008. We continue to evaluate the cost of restoring our platforms to operation with initial estimated costs of $30 million to $35 million, a portion of which will be capitalized and a portion of which will be expensed.

- Capital expenditures, excluding acquisitions, of approximately $1.8 billion which is approximately $100 million lower than previously disclosed guidance. While approximately 85% of our planned 2008 capital program is allocated to our domestic program, we expect approximately $275 million in international capital expenditures in 2008, primarily in our Brazil exploration and development program. This amount includes approximately $100 million of development capital expenditures related to the Camarupim project, the timing of which will depend on finalization of commercial agreements with our partner and regulatory approvals.

- Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.98/Mcfe to $2.04/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, the volumetric impact of hurricanes mentioned above and hurricane repair costs; and

- Depreciation, depletion and amortization rate of between $2.92/Mcfe and $2.96/Mcfe.

Table of Contents

Price Risk Management Activities

As part of our strategy, we enter into derivative contracts on our natural gas and oil production to stabilize cash flows, to reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. Because this strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. Adjustments to our hedging strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

During the nine months ended September 30, 2008, we entered into option and swap contracts on approximately 54 TBtu of our anticipated 2008 natural gas production and 172 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 is marked-to-market in our earnings each period.

The following tables reflect the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of September 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	6	$ 7.47	28	$8.00	28	$10.87
2009	4	$ 3.56	126	$8.93	101	$14.58
2010	5	$ 3.70				
2011-2012	6	$ 3.88				
Oil						
2008	430	$ 88.57				
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		**Western-Raton**		**Rockies**	
	Volumes	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**

Natural Gas												
2008	2	$ 8.24	6	$8.00	6	$10.32	15	$(0.33)	6	$(1.14)	3	$(1.37)
2009	4	$ 12.06	42	$9.61	42	$17.40			15	$(1.00)		
Oil												
2008(3)	200	$ 88.28										
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.

(3) During the third quarter of 2008, we were required to remove the hedging designation on fixed price swaps associated with 200 MBbls of our 2008 crude

oil production due to the impact of Hurricane Ike on our forecasted 2008 crude oil production volumes.

Table of Contents

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.

Operating Results and Variance Analysis

The tables below and discussion that follows provide our financial results and an analysis of significant variances in those results during the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions)			
Operating Revenues:				
Natural gas	$ 505	$ 431	$ 1,547	$ 1,298
Oil, condensate and NGL	139	129	435	328
Changes in fair value of derivative contracts not designated as accounting hedges	214	6	104	4
Other	23	9	53	25
Total operating revenues	881	575	2,139	1,655
Operating Expenses:				
Cost of products	(13)	(6)	(28)	(15)
Transportation costs	(23)	(19)	(63)	(53)
Production costs	(96)	(79)	(280)	(249)
Depreciation, depletion and amortization	(191)	(194)	(600)	(553)
General and administrative expenses	(26)	(46)	(116)	(141)
Other	(4)	(3)	(17)	(10)
Total operating expenses	(353)	(347)	(1,104)	(1,021)
Operating income	528	228	1,035	634
Other income(1)	4	4	43	12
EBIT	$ 532	$ 232	$ 1,078	$ 646

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

Table of Contents

	Quarters Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Percent Variance	2008	2007	Percent Variance
Consolidated volumes, prices and costs per unit:						
Natural gas						
Volumes (MMcf)	56,609	60,705	(7)%	178,688	177,222	1%
Average realized prices including hedges ($/Mcf)	$ 8.92	$ 7.12	25%	$ 8.66	$ 7.33	18%
Average realized prices excluding hedges ($/Mcf)	$ 9.58	$ 5.92	62%	$ 9.23	$ 6.52	42%
Average transportation costs ($/Mcf)	$ 0.37	$ 0.29	28%	$ 0.32	$ 0.28	14%
Oil, condensate and NGL						
Volumes (MBbls)	1,571	1,948	(19)%	5,079	5,684	(11)%
Average realized prices including hedges ($/Bbl)	$ 88.17	$ 66.26	33%	$ 85.60	$ 57.71	48%
Average realized prices excluding hedges ($/Bbl)	$ 99.77	$ 66.82	49%	$ 94.81	$ 58.36	62%
Average transportation costs ($/Bbl)	$ 1.18	$ 0.84	40%	$ 0.97	$ 0.76	28%
Total equivalent volumes						
MMcfe	66,033	72,392	(9)%	209,161	211,327	(1)%
MMcfe/d	718	787	(9)%	763	774	(1)%
Production costs and other cash operating costs ($/Mcfe)						
Average lease operating expenses	$ 0.96	$ 0.83	16%	$ 0.85	$ 0.87	(2)%
Average production taxes(1)	0.50	0.26	92%	0.49	0.31	58%
Total production costs	1.46	1.09	34%	1.34	1.18	14%
Average general and administrative expenses	0.38	0.64	(41)%	0.56	0.67	(16)%
Average taxes, other than production and income taxes	0.05	0.04	25%	0.04	0.04	%
Total cash operating costs	$ 1.89	$ 1.77	7%	$ 1.94	$ 1.89	3%
Depreciation, depletion and amortization ($/Mcfe)	$ 2.89	$ 2.69	7%	$ 2.87	$ 2.62	10%
Unconsolidated affiliate volumes (Four Star)						
Natural gas (MMcf)	5,351	4,107		15,399	13,854	
Oil, condensate and NGL (MBbls)	263	254		797	756	

Total equivalent volumes				
MMcfe	6,929	5,634	20,180	18,389
MMcfe/d	75	61	74	67

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

Table of Contents

Quarter and Nine Months Ended September 30, 2008 Compared to Quarter and Nine Months Ended September 30, 2007

Our EBIT for the quarter and nine months ended September 30, 2008 increased $300 million and $432 million as compared to the same periods in 2007. The table below shows the significant variances in our operating results for the quarter and nine months ended September 30, 2008 as compared to the same periods in 2007:

	Quarter Ended September 30, 2008 Variances				Nine Months Ended September 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	$ 207	$	$	$ 207	$ 485	$	$	$ 485
Impact of hedges	(110)			(110)	(246)			(246)
Higher (lower) volumes in 2008	(23)			(23)	10			10
Oil, Condensate and NGL Revenues								
Higher realized prices in 2008	52			52	185			185
Impact of hedges	(17)			(17)	(43)			(43)
Lower volumes in 2008	(25)			(25)	(35)			(35)
Other Revenue								
Changes in fair value of derivatives not designated as accounting hedges	208			208	100			100
Other	14			14	28			28
Depreciation, Depletion and Amortization Expense								
Higher depletion rate in 2008		(13)		(13)		(52)		(52)
Lower production volumes in 2008		16		16		5		5
Production Costs								
Lower (higher) lease operating expenses in 2008		(3)		(3)		6		6
Higher production taxes in 2008		(14)		(14)		(37)		(37)
General and Administrative Expenses		20		20		25		25
Other								

Earnings from investment in Four Star			8	8			32	32
Other		(12)	(8)	(20)		(30)	(1)	(31)
Total Variances	$ 306	$ (6)	$	$ 300	$ 484	$ (83)	$ 31	$ 432

Natural gas, oil, condensate and NGL revenues. During the quarter and nine months ended September 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 $56 million and $149 million during the quarter and nine months ended September 30, 2008, as compared to gains of $71 million and $140 million in the same periods in 2007. During the quarter and nine months ended September 30, 2008, we also benefited from an increase in production volumes in our Central and Texas Gulf Coast regions compared to the same periods in 2007, primarily as a result of our Peoples acquisition. Our Gulf of Mexico and south Louisiana region production volumes decreased in the third quarter of 2008 versus the same period in 2007 primarily due to production shut in as a result of Hurricanes Ike and Gustav.

Other revenue. During the quarter and nine months ended September 30, 2008, we recognized mark-to-market gains of $214 million and $104 million compared to gains of $6 million and $4 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 nine months ended September 30, 2008, we paid $1 million and $19 million on contracts that were settled during the period, compared to payments of $6 million and $25 million on contracts that were 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.

Table of Contents

Production costs. Our production costs increased during 2008 as compared to the same periods in 2007 primarily due to higher production taxes which increased due to higher natural gas and oil revenues. The increase in production taxes was partially offset by a reduction in lease operating expenses for the nine months ended September 30, 2008, primarily as a result of the impact of divested properties in the Gulf of Mexico and south Louisiana region.

General and administrative expenses. Our general and administrative expenses decreased during 2008 as compared to the same periods in 2007 due primarily to the reversal of a $20 million accrual as a result of a favorable ruling on a legal matter.

Other. Our equity earnings from Four Star for 2008 increased as compared to 2007 primarily due to higher natural gas prices, higher production volumes and an increase in our equity ownership in Four Star from 43 percent to 49 percent in the third quarter of 2007.

Other Matter

We conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. This test, referred to as a ceiling test , evaluates, on an after tax basis, our current capitalized costs in each pool against the discounted present value of future net revenues from proved reserves plus the lower of cost or fair value of unproved properties. The ceiling tests are impacted by a number of factors that are subject to change each time the tests are performed, including spot prices, locational basis differences, changes in proved reserve estimates, and estimated future costs of developing and producing proved reserves. We performed ceiling test calculations on each of our full cost pools at September 30, 2008 using spot prices as of the end of the period and did not recognize a charge. The ceiling tests also included the impact of derivatives designated as accounting hedges on our future cash flows. Subsequent to September 30, 2008, prices of oil and natural gas have declined, and although these declines did not impact the third quarter ceiling tests, sustained lower commodity prices could result in ceiling test charges in future periods depending on changes to the factors discussed above.

Marketing Segment

Overview. Our Marketing segment s primary focus is marketing our Exploration and Production segment s natural gas and oil production and managing our 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 nine months ended September 30, 2008, we generated EBIT of $82 million and an EBIT loss of $131 million, primarily driven by changes in the fair value of our PJM power contracts and production-related natural gas and oil derivative contracts. Our 2008 year to date losses were due primarily to significant increases in locational PJM power price differences as well as increases in natural gas and oil prices, while our EBIT for the quarter ended September 30, 2008 was due to significant decreases in both commodity prices and differences in locational PJM power prices. Our third quarter 2008 results also included gains resulting from changes in the interest rates used to determine the fair market value of these contracts. The third quarter gains on these contracts partially offset the losses incurred in the first half 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 September 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 $20 million. As of September 30, 2008, a 1 percent change in interest rates would change the fair market value of our derivatives by approximately $21 million.

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions)			
Production-Related Natural Gas and Oil Derivative Contracts:				
Changes in fair value of options and swaps	$ 14	$ 15	$ (59)	$ (63)
Contracts Related to Legacy Trading Operations:				
Natural gas transportation-related contracts:				
Demand charges	(8)	(27)	(27)	(82)
Settlements, net of termination payments	13	18	37	54
Changes in fair value of other natural gas derivative contracts(1)	7	(4)	18	(26)
Changes in fair value of power contracts(2)	63	(11)	(83)	(43)
Total revenues	89	(9)	(114)	(160)
Operating expenses	(7)	(4)	(18)	(9)
Operating loss	82	(13)	(132)	(169)
Other income, net(3)		5	1	31

EBIT	$ 82	$ (8)	$ (131)	$ (138)

(1) Includes $17 million and $19 million of revenue for the quarter and nine months ended September 30, 2008 related to bankruptcy settlements.

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

(3) Includes a $23 million gain on the sale of our investment in the NYMEX in the first quarter of 2007 and $5 million of interest income in the third quarter of 2007 related to the settlement of outstanding California power price disputes.

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 September 30, 2008, our remaining contracts in this segment included 223 MBbl of 2008 oil option contracts with a floor price of $55 per Bbl and an average ceiling price of $56.10 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 nine months ended September 30, 2008 and 2007, increases in commodity prices decreased the fair value of our option contracts resulting in losses on these contracts, whereas during the quarters ended September 30, 2008 and 2007, decreases in commodity prices increased the fair value of our option contracts resulting in gains on these contracts. During the nine months ended September 30, 2008, we paid approximately $39 million on contracts settled during that period, while during the nine months ended September 30, 2007, we received approximately $42 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 September 30, 2008, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. For 2008, we anticipate annual demand charges related to this capacity of approximately $41 million which we expect to 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 and requires 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 nine months ended September 30, 2008, we incurred mark-to-market losses of $83 million on our PJM contracts due primarily to a more than 40 percent increase in the difference in forward power prices at specific delivery locations in the PJM eastern region compared to those in the PJM west hub. However, during the third quarter 2008, we recorded mark-to-market gains on these contracts of $63 million as the locational difference in forward power prices between these regions decreased during the quarter by approximately 30 percent. Also impacting our results for the nine months ended September 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 nine months ended September 30, 2008, total cash settlements paid on our PJM contracts were $19 million and $52 million, of which $7 million and $19 million were related to our obligations to swap locational differences in prices within the PJM region.

Power Segment

As of September 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 first half of 2008, we sold our remaining Central American power investment, an Asian power investment and transferred the ownership of our Manaus and Rio Negro power plants in Brazil to the plants power purchaser. 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 remaining investments. As of September 30, 2008, our net remaining investment, guarantees and letters of credit related to power projects in this segment totaled approximately $437 million which consisted of approximately $421 million in equity investments and notes and accounts receivable and approximately $16 million in financial guarantees and letters of credit, as follows (in millions):

South America	
Porto Velho	$ 211
Manaus & Rio Negro	52
Pipeline projects	149
Asia	25
Total investment, guarantees and letters of credit	$ 437

Operating Results. For the quarter ended September 30, 2008, our Power segment generated an EBIT loss of $6 million due primarily to foreign exchange losses on the Brazil reais denominated receivables we have related to our Manaus and Rio Negro projects. We are in the process of resolving several outstanding claims related to the Manaus and Rio Negro projects that are also denominated in Brazilian reais. The ultimate resolution of these matters could impact our results in the future. For a further discussion of these matters, see Item 1, Financial Statements, Note 12. This loss is offset by second quarter gains recognized on the sale of investments in Asia and Central America, resulting in EBIT of $4 million for the nine months ended September 30, 2008. For the quarter and nine months ended September 30, 2007, we generated EBIT losses of $67 million and $33 million. Our 2007 third quarter results were negatively impacted by losses of $57 million on our interests in Porto Velho and $7 million on our interest in the Manaus and Rio Negro projects based on adverse developments at these projects. In 2007 and 2008, we did not recognize earnings from our Asian and Central American investments, and in the second half of 2007 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 September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	(In millions)			
Loss on extinguishment of debt	$	$	$	$ (287)
Change in litigation, insurance and other reserves	(7)	56	50	21
Foreign currency fluctuations on Euro-denominated debt	5	(4)	(1)	(7)

Gain on disposition of a portion of our telecommunications business			18	
Other	(3)	(1)	8	10
Total EBIT	$ (5)	$ 51	$ 75	$ (263)

Extinguishment of Debt. During 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 that also affect our corporate results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may further impact our future results.

During the nine months ended September 30, 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 this adjustment was 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 2008. It is uncertain whether these price increases will continue in the long-term based on the illiquid nature of the forward market for ammonia. Further changes in ammonia prices may continue to impact this contract, which could impact our results in the future.

During the third quarter of 2007, we recorded a gain of approximately $77 million on the reversal of a liability related to The Coastal Corporation s legacy crude oil marketing and trading business.

Interest and Debt Expense

Our interest and debt expense was $7 million and $67 million lower in the quarter and nine months ended September 30, 2008 compared with the same periods in 2007 primarily due to lower average debt balances in 2008 when compared to 2007.

Income Taxes

	Quarters Ending September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In millions, except for rates)			
Income taxes	$215	$100	$450	$151
Effective tax rate	33%	39%	34%	35%

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

Discontinued Operations

Income from our discontinued operations was $674 million for the nine months ended September 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.

Liquidity and Capital Resources

Over the past several years, we have focused on expanding our core pipeline and exploration and production operations to provide for long-term growth. During this period, we also strengthened our balance sheet primarily through significant debt reductions.

During the third quarter of 2008, the global credit markets experienced significant instability. Although we continue to assess the impact of these market developments, this instability could restrict our future access to the credit markets, and will likely impact the cost of any debt that is obtained in the future. As a result of this instability, we have implemented certain actions and anticipate implementing further actions for the remainder of 2008 and 2009 in response to the current volatility in the financial markets. These actions include reducing our capital program for the remainder of 2008 and 2009, partnering on one or more expansion projects and the expected sale of certain non-core assets as previously described.

Throughout 2008, we have completed a series of financing transactions. In September 2008, we successfully completed a dropdown of an additional 30% interest in CIG and 15% interest in SNG to El Paso Pipeline Partners (EPB) which generated debt and equity capital for us of $254 million. These funds supplement approximately $925 million in debt and equity capital generated in conjunction with EPB s initial public offering in November 2007 in which we contributed 10% interests in CIG and SNG. We currently have a 72% limited partner interest and a 2% general partner interest in EPB. During 2008, we also secured approximately $870 million of project financing for our Gulf LNG Clean Energy project and entered into new agreements that provide us approximately $450 million in additional letters of credit to support our obligations to purchase pipe associated with constructing our Ruby pipeline project.

Available Liquidity. At September 30, 2008, we had approximately $1.2 billion of cash and approximately $0.7 billion of capacity available to us under various credit facilities, excluding $150 million available to El Paso Pipeline Partners under its revolving credit facility. Traditionally, we have pursued additional bank financings, project financings or debt capital markets transactions to supplement our available cash and credit facilities which we have used to fund the capital expenditure programs of our pipeline and exploration and production operations, meet operating needs and repay debt maturities. Based upon our current and projected liquidity following our debt maturities that become due in May 2009, we do not currently contemplate having to access the capital markets until the second half of 2009. Although there are many different factors that will determine our actual capital and liquidity requirements in the future, we currently expect that we would seek to raise between $500 million to $800 million of capital in the second half of 2009. However, we will be opportunistic in accessing the capital markets prior to that time. Our debt maturities reflects our 380 million Euro-denominated debt at the Euro spot rate as of September 30, 2008. However, our Euro denominated debt is approximately 87% hedged at an average exchange rate of approximately 1.1495, which, as of September 30, 2008, reduces the cash required to meet our maturities to approximately $1.0 billion.

To the extent the financial markets remain restricted, any of the asset sales or partnering opportunities set forth above are delayed or cannot be completed or there is a further decline in commodity prices, we would review other alternatives, including additional reductions in our discretionary capital program, secured financing arrangements, seeking partners for one or more of our growth projects and the sale of additional non-core assets. For additional information, refer to the previous discussion in *Overview* and *Liquidity/Cash Flow Outlook* below.

2008 Cash Flow Activities. During the first nine months of 2008, we generated operating cash flow of approximately $2.1 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 $0.8 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 repurchases of approximately $0.3 billion of notes of our subsidiaries, SNG and CIG.

Table of Contents

For the nine months ended September 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	$	0.9
Other income adjustments		1.4
Changes in assets and liabilities		(0.2)
Total cash flow from operations	$	2.1
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$	0.7
Other		0.1
Continuing financing activities		
Net proceeds from the issuance of long-term debt[1]		4.1
Total other cash inflows	$	4.9
Cash Outflows		
Continuing investing activities		
Capital expenditures	$	1.9
Cash paid for acquisitions		0.4
		2.3
Continuing financing activities		
Payments to retire long-term debt and other financing obligations[1]		3.6
Dividends and other		0.2
		3.8
Total cash outflows	$	6.1
Net change in cash	$	0.9

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

Liquidity/Cash Flow Outlook. For the remainder of 2008, we expect continued strong operating cash flows from our core pipeline business. For the remainder of 2008, we expect earnings and cash flow in our exploration and production business to be impacted by the decline in commodity prices and the continued effects on production volumes caused by recent hurricanes. As a result of a strong commodity price environment in the first nine months of 2008, we anticipate we will generate cash flows in excess of amounts originally planned for the full year. Although the financial markets are volatile, as noted in *Available Liquidity* above, we believe we will have sufficient sources of liquidity to meet our operating needs, repay debt maturities, and fund our 2009 capital program. In light of the current volatility of the financial markets, however, it is possible additional adjustments to our plan and outlook will be required which could impact our financial and operating performance. A prolonged period of restricted access to the credit markets could also impact our long-term growth potential.

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

	Nine Months Ended September 30, 2008	**2008 Remaining**	**Total**
		(In billions)	
Pipelines			
Maintenance	$ 0.3	$ 0.2	$ 0.5
Growth	0.8	0.4	1.2
Exploration and Production	1.2	0.6	1.8
	$ 2.3	$ 1.2	$ 3.5

45

Table of Contents

Additional Factors That Could Impact Our Future Liquidity. Our liquidity needs could increase or decrease based on changes in any of the factors noted above, as well as certain other factors such as the margining requirements of our price risk management activities or capital requirements to repair recent hurricane damage. 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 September 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**		**Raton**		**Rockies**	
	Volumes	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**
Natural Gas												
2008	8	$ 7.66	34	$ 8.00	34	$10.77	15	$(0.33)	6	$(1.14)	3	$(1.37)
2009	8	$ 7.33	168	$ 9.10	143	$15.41			15	$(1.00)		
2010	5	$ 3.70										
2011-2012	6	$ 3.88										
Oil												
2008	630	$ 88.48	223	$55.00	223	$56.10						
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.

We currently post letters of credit for the required margin on certain of our derivative contracts. For the remainder of 2008, based on prices as of September 30, 2008, we expect approximately $0.1 billion of the total of $1.0 billion in collateral outstanding at September 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 September 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.

On certain other derivative contracts recorded as assets, we are exposed to (and have adjusted the fair value of these contracts for) the risk that our counterparties may not be able to perform or post the necessary collateral with us. We have assessed this counterparty non-performance risk given the recent instability in the credit markets and determined that our exposure is primarily limited to seven financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

Hurricanes. During the third quarter of 2008, our pipeline and exploration and production facilities were damaged by Hurricanes Ike and Gustav. We continue to assess the damages resulting from these hurricanes and the corresponding impact on estimated costs to repair and abandon impacted facilities. Although our estimates may change in the future, we currently estimate total repair and abandonment costs on our pipelines of between approximately $80 million and $120 million, a majority of which we expect will be capital expenditures. We also estimate total repair costs between $30 million and $35 million in our exploration and production business, a majority of which we expect will be capital expenditures. We expect to spend these amounts in 2008 and 2009, none of which are recoverable from insurance.

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 and oil 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 September 30, 2008:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Total Fair Value
			(In millions)		
Derivatives designated as accounting hedges					
Assets	$ 159	$ 39	$	$	$ 198
Liabilities	(20)	(39)	(13)		(72)
Total derivatives designated as hedges(1)	139		(13)		126
Other commodity-based derivatives					
Assets	144	150	36	15	345
Liabilities	(235)	(412)	(228)	(133)	(1,008)
Total other commodity-based derivatives(1)(2)	(91)	(262)	(192)	(118)	(663)
Total commodity-based derivatives	$ 48	$ (262)	$ (205)	$ (118)	$ (537)

(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 nine months ended September 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	117	248	365
Changes in fair value of contracts	9	(35)	(26)
Reclassification of derivatives that no longer qualify as hedges	2	(2)	
Option premiums (received) paid	21	(5)	16
Net changes in contracts outstanding during the period	149	206	355
Fair value of contracts outstanding at September 30, 2008	$ 126	$ (663)	$ (537)

Other Purchase Obligations. During 2008, we entered into contracts to purchase pipe primarily associated with the Ruby Pipeline project and TGP s 300 Line expansion which are anticipated to be placed in service between 2010 and 2011. Our estimated obligations under these agreements are approximately $80 million for the remainder of 2008, $660 million in 2009 and $143 million in 2010.

Table of Contents

Critical Accounting Estimates

Listed below are updates to our critical accounting estimates described in our 2007 Annual Report on Form 10-K. We consider our critical accounting estimates to be those that require difficult, complex, or subjective judgment necessary in accounting for inherently uncertain matters and those that could significantly influence our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates.

Price Risk Management Activities. As stated in our 2007 Annual Report on Form 10-K, we estimate the fair values of our derivatives using exchange prices, third party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information provided by third-party pricing sources and models that rely on this forward pricing information. The extent to which we rely on pricing information received from third parties in developing these assumptions is based, in part, on whether the information considers the availability of observable data in the marketplace. For example, in relatively illiquid markets such as the PJM forward power market and the forward market for ammonia, we may make adjustments to the pricing information we receive from third parties based on our evaluation of these sources.

In addition to pricing assumptions, another significant assumption we use in determining the fair value of our derivatives is that related to the risk of non-performance of our counterparties. We adjust the fair value of our derivative assets for the risk of non-performance of our counterparties considering the collateral posted for the derivative and changes in the counterparties creditworthiness, which is measured in part based on changes in their bond yields, changes in actively traded credit default swap prices (if available) and other information about their credit standing. We adjust the fair value of our derivative liabilities for El Paso s creditworthiness utilizing similar inputs.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

Production-Related Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These derivative contracts are entered into by both our Exploration and Production and Marketing segments. 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 derivatives net assets (liabilities)					
September 30, 2008	$ 240	$ 95	$(145)	$ 400	$160
December 31, 2007	$ (64)	$(181)	$(117)	$ 58	$122
Other commodity-based derivatives net liabilities					
September 30, 2008	$(777)	$(795)	$ (18)	$(759)	$ 18
December 31, 2007	$(828)	$(846)	$ (18)	$(810)	$ 18

Table of Contents

Interest Rate Risk

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 derivatives net assets (liabilities)					
September 30, 2008	$ 240	$ 239	$ (1)	$ 241	$ 1
December 31, 2007	$ (64)	$ (62)	$ 2	$ (66)	$ (2)
Other commodity-based derivatives net liabilities					
September 30, 2008	$(777)	$(756)	$ 21	$(798)	$(21)
December 31, 2007	$(828)	$(805)	$ 23	$(853)	$(25)

50

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 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 September 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 third quarter of 2008.

Table of Contents

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 (PSD) permit when the generators were first installed, and CIG promptly reported those test data to the EPA. We have reached an agreement with the DOJ under which we will pay a total of $1.27 million to settle all of these Title V and PSD issues at the Natural Buttes Compressor Station. We are working with the DOJ to draft and finalize a definitive settlement agreement.

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, such as limited access to the capital markets, 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. Also see Overview and Liquidity and Capital Resources under Part I, Item 2, Management s Discussion and Analysis of Financial Condition and Results of Operations.

Table of Contents

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 September 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)
July 1, 2008 to July 31, 2008	1,465,253	$ 18.40	1,465,253	$268,773,153
August 1, 2008 to August 31, 2008	1,494,100	$ 16.73	1,494,100	$243,774,407
September 1, 2008 to September 30, 2008	1,500,000	$ 14.18	1,500,000	$222,511,157
Quarter Ended September 30, 2008 Total	4,459,353	$ 16.42	4,459,353	$222,511,157

(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.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

53

Table of Contents

SIGNATURES

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

EL PASO CORPORATION

Date: November 7, 2008

/s/ D. Mark Leland
D. Mark Leland
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: November 7, 2008

/s/ John R. Sult
John R. Sult
Senior Vice President and Controller
(Principal Accounting Officer)

Table of Contents

EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed with this Report.

Exhibit Number	Description
12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.B	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.