

PETROLEUM DEVELOPMENT CORP
Form 10-Q
November 06, 2008

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

FORM 10-Q

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

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: 000-07246

PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)

Nevada
(State of incorporation)

95-2636730
(I.R.S. Employer Identification No.)

120 Genesis Boulevard
Bridgeport, West Virginia 26330
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (304) 842-3597

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 No

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

Large	Accelerated
accelerated	filer <input checked="" type="checkbox"/>
filer <input type="checkbox"/>	
Non-accelerated	Smaller
filer <input type="checkbox"/>	reporting
	company <input type="checkbox"/>

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 14,862,225 shares of the Company's Common Stock (\$.01 par value) were outstanding as of October 31, 2008.

PETROLEUM DEVELOPMENT CORPORATION

INDEX

PART I – FINANCIAL INFORMATION

Item 1.	<u>Financial Statements (unaudited)</u>	
	<u>Condensed Consolidated Balance Sheets</u>	2
	<u>Condensed Consolidated Statements of Operations</u>	3
	<u>Condensed Consolidated Statements of Cash Flows</u>	4
	<u>Notes to Condensed Consolidated Financial Statements</u>	5
Item 2.	<u>Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	18
Item 3.	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	29
Item 4.	<u>Controls and Procedures</u>	31

PART II – OTHER INFORMATION

Item 1.	<u>Legal Proceedings</u>	32
Item 1A.	<u>Risk Factors</u>	32
Item 2.	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	33
Item 3.	<u>Defaults Upon Senior Securities</u>	33
Item 4.	<u>Submission of Matters to a Vote of Security Holders</u>	33
Item 5.	<u>Other Information</u>	33
Item 6.	<u>Exhibits</u>	34

	<u>SIGNATURES</u>	35
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Index

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements (unaudited)

Petroleum Development Corporation
Condensed Consolidated Balance Sheets
(in thousands, except share and per share data)

	September 30, 2008	December 31, 2007*
Assets		
Current assets:		
Cash and cash equivalents	\$ 47,404	\$ 84,751
Accounts receivable, net	67,386	60,024
Accounts receivable - affiliates	19,547	11,537
Fair value of derivatives	56,713	4,817
Other current assets	45,583	30,664
Total current assets	236,633	191,793
Properties and equipment, net	987,737	845,864
Restricted cash - long term	2,150	1,294
Other assets	52,481	11,528
Total assets	\$ 1,279,001	\$ 1,050,479
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	\$ 88,225	\$ 88,502
Accounts payable - affiliates	16,932	3,828
Federal and state income taxes payable	1,580	901
Fair value of derivatives - current	13,840	6,291
Advances for future drilling contracts	5,157	68,417
Funds held for future distribution	70,354	39,823
Other accrued expenses	35,803	34,243
Total current liabilities	231,891	242,005
Long-term debt	322,294	235,000
Deferred income taxes	183,362	136,490
Other liabilities	71,551	40,699
Total liabilities	809,098	654,194
Commitments and contingencies		
Minority interest in consolidated limited liability company	710	759
Preferred shares, par value \$.01 per share; authorized: 50,000,000 shares; issued: none	-	-
Common shares, par value \$.01 per share; authorized: 100,000,000 shares; issued: 14,907,679 in 2007 and 14,861,299 in 2008	149	149
Additional paid-in capital	4,465	2,559
Retained earnings	464,853	393,044
Treasury shares at cost	(274)	(226)

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Total shareholders' equity	469,193	395,526
Total liabilities and shareholders' equity	\$ 1,279,001	\$ 1,050,479

*Derived from audited 2007 balance sheet.

See accompanying notes to condensed consolidated financial statements.

Index

Petroleum Development Corporation
Condensed Consolidated Statements of Operations
(unaudited; in thousands except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues:				
Oil and gas sales	\$ 99,422	\$ 44,437	\$ 265,617	\$ 117,699
Sales from natural gas marketing activities	53,372	19,934	107,638	71,845
Oil and gas well drilling operations	1,232	1,573	7,202	7,342
Well operations and pipeline income	3,356	2,092	8,146	6,682
Oil and gas price risk management gain, net	169,402	6,345	25,294	4,442
Other	20	1,894	57	2,122
Total revenues	326,804	76,275	413,954	210,132
Costs and expenses:				
Oil and gas production and well operations cost	22,173	12,645	61,120	33,308
Cost of natural gas marketing activities	54,372	19,810	106,610	70,102
Cost of oil and gas well drilling operations	501	749	1,097	1,559
Exploration expense	10,212	5,337	17,962	14,795
General and administrative expense	8,106	7,513	27,160	21,823
Depreciation, depletion and amortization	28,645	20,354	71,881	50,857
Total costs and expenses	124,009	66,408	285,830	192,444
Gain on sale of leaseholds	-	-	-	25,600
Income from operations	202,795	9,867	128,124	43,288
Interest income	151	462	497	2,059
Interest expense	(7,817)	(2,544)	(19,143)	(4,825)
Income before income taxes	195,129	7,785	109,478	40,522
Provision for income taxes	68,233	3,326	37,222	15,511
Net income	\$ 126,896	\$ 4,459	\$ 72,256	\$ 25,011
Earnings per share				
Basic	\$ 8.59	\$ 0.30	\$ 4.90	\$ 1.70
Diluted	\$ 8.55	\$ 0.30	\$ 4.86	\$ 1.68
Weighted average common shares outstanding				
Basic	14,767	14,757	14,749	14,739
Diluted	14,835	14,827	14,858	14,845

See accompanying notes to condensed consolidated financial statements.

Index

Petroleum Development Corporation
Condensed Consolidated Statements of Cash Flows
(unaudited, in thousands)

	Nine Months Ended September	
	30,	
	2008	2007
Cash flows from operating activities:		
Net income	\$ 72,256	\$ 25,011
Adjustments to net income to reconcile to cash provided by (used in) operating activities:		
Deferred income taxes	45,390	14,833
Depreciation, depletion and amortization	71,881	50,857
Allowance for doubtful accounts	130	-
Amortization of debt issuance costs	956	280
Accretion of asset retirement obligation	916	712
Exploratory dry hole costs	5,038	969
Gain from sale of assets	(88)	(1)
Gain from sale of leaseholds	-	(25,600)
Expired and abandoned leases	3,492	1,246
Stock-based compensation	5,239	1,652
Unrealized gain on derivative transactions	(45,371)	(1,256)
Excess tax benefits from stock based compensation	(1,136)	(500)
Increase in current assets	(28,138)	(34,879)
(Increase) decrease in other assets	(255)	220
Decrease in current liabilities	(27,873)	(68,302)
Increase in other liabilities	1,355	1,958
Net cash provided by (used in) operating activities	103,792	(32,800)
Cash flows from investing activities:		
Capital expenditures	(219,273)	(158,727)
Acquisitions	-	(201,594)
Decrease in restricted cash for property acquisition	-	191,178
Other	121	684
Net cash used in investing activities	(219,152)	(168,459)
Cash flows from financing activities:		
Proceeds from credit facility	339,500	238,000
Proceeds from senior notes	200,101	-
Repayment of credit facility	(452,500)	(203,000)
Payment of debt issuance costs	(5,308)	(591)
Proceeds from exercise of stock options	605	182
Excess tax benefits from stock based compensation	1,136	500
Minority interest investment	-	800
Purchase of treasury stock	(5,521)	(346)

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Net cash provided by financing activities	78,013	35,545
Net decrease in cash and cash equivalents	(37,347)	(165,714)
Cash and cash equivalents, beginning of period	84,751	194,326
Cash and cash equivalents, end of period	\$ 47,404	\$ 28,612
Supplemental disclosure of cash flow information of cash payments for:		
Interest	\$ 18,847	\$ 6,991
Income taxes	9,224	43,615
Supplemental schedule of non-cash investing and financing activities:		
Change in deferred tax liability resulting from the allocation of acquisition purchase price	-	4,188
Changes in accounts payable related to the acquisitions of partnerships	-	668
Changes in accounts payable related to purchase of properties and equipment	6,481	34,150
Changes in accounts payable-affiliates related to investment in drilling partnership	-	18,712
Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	631	5,527

See accompanying notes to condensed consolidated financial statements.

Index

Petroleum Development Corporation
Notes to Condensed Consolidated Financial Statements
September 30, 2008
(unaudited)

1. GENERAL

Petroleum Development Corporation ("PDC"), together with our consolidated entities (the "Company"), is an independent energy company engaged primarily in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas operations in 1969, we have grown primarily through exploration and development activities, the acquisition of producing oil and natural gas wells and the expansion of our natural gas marketing activities.

The accompanying interim condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. Minority interest in earnings and ownership has been recorded for the percentage of the LLC we do not own. We account for our investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, our accompanying interim condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships has been eliminated.

The accompanying interim condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission ("SEC"). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying interim condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The interim results of operations for the nine months ended September 30, 2008, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying interim condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007, as filed with the SEC on March 20, 2008 ("2007 Form 10-K").

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

We adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, Fair Value Measurements, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and nonfinancial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances. In February 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") FAS No. 157-2, Effective Date of FASB Statement No. 157, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements

on a recurring basis (at least annually). Nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include those initially measured at fair value, including our asset retirement obligations. As of the adoption date, we have applied the provisions of SFAS No. 157 to our recurring measurements and the impact was not material to our underlying fair values and no amounts were recorded relative to the cumulative effect of a change in accounting. We are currently evaluating the potential effect that the nonfinancial assets and liabilities provisions of SFAS No. 157 will have on our financial statements when adopted in 2009. See Note 5 for further details on our fair value measurements.

In October 2008, the FASB issued FSP No. FAS 157-3, Determining the Fair Value of a Financial Asset in a Market That Is Not Active, which applies to financial assets within the scope of accounting pronouncements that require or permit fair value measurements in accordance with SFAS No. 157. This FSP clarifies the application of SFAS No. 157 in a market that is not active and defines additional key criteria in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 was effective upon issuance and did not have a material impact on our financial statements.

Index

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. As of September 30, 2008, we had not elected, nor do we intend, to measure additional financial assets and liabilities at fair value.

In April 2007, the FASB issued FSP No. FIN 39-1, Amendment of FASB Interpretation No. 39 ("FIN 39-1"), to amend certain portions of Interpretation 39. FIN 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. The January 1, 2008, adoption of FSP FIN 39-1 had no impact on our financial statements.

Recently Issued Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations ("SFAS No. 141R"). SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, Accounting for Income Taxes, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, Accounting for Uncertainty in Income Taxes, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements—An Amendment of ARB No. 51. SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Additionally, SFAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. We are evaluating the impact that SFAS No. 160 will have, if any, on our consolidated financial statements and related disclosures when it is adopted in 2009.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities—An Amendment of FASB Statement No. 133, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations and (c) how derivative instruments and related hedged items affect an entity's

financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. As SFAS No. 161 is disclosure related, we do not expect its adoption to have a material impact on our financial statements.

Index

3. PROPERTIES AND EQUIPMENT

	September 30, 2008	December 31, 2007
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	\$ 1,152,534	\$ 953,904
Unproved	40,365	41,023
Total oil and gas properties	1,192,899	994,927
Pipelines and related facilities	31,190	22,408
Transportation and other equipment	29,296	23,669
Land and buildings	14,449	11,303
Construction in progress (1)	-	2,929
	1,267,834	1,055,236
Accumulated depreciation, depletion and amortization ("DD&A")	(280,097)	(209,372)
	\$ 987,737	\$ 845,864

(1) At December 31, 2007, includes costs primarily related to a new integrated oil and gas financial software system.

Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in properties and equipment in the accompanying condensed consolidated balance sheets.

	Amount (in thousands)	Number of Wells
Beginning balance at December 31, 2007	\$ 2,300	3
Additions to capitalized exploratory well costs pending the determination of proved reserves	13,526	13
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(7,626)	(6)
Capitalized exploratory well costs charged to expense	(5,040)	(3)
Ending balance at September 30, 2008	\$ 3,160	7

As of September 30, 2008, none of the seven suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year.

4. DERIVATIVE FINANCIAL INSTRUMENTS

Our derivative instruments do not qualify for use of hedge accounting under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, as amended. Accordingly, we recognize all derivative instruments as either assets or liabilities on our accompanying condensed consolidated balance sheets at fair value, and changes in the derivatives' fair values are recorded on a net basis in our accompanying condensed

consolidated statements of operations. Changes in fair value of derivative instruments related to our oil and gas sales activity are recorded in oil and gas price risk management, net, and changes in fair value of derivatives related to our natural gas marketing activities are recorded in sales from and cost of natural gas marketing activities.

We are exposed to the effect of market fluctuations in the prices of oil and natural gas as they relate to our oil and natural gas sales and natural gas marketing segments. Price risk represents the potential risk of loss from adverse changes in the market price of oil and natural gas commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivatives. Our policy prohibits the use of oil and natural gas derivative instruments for speculative purposes.

Index

Economic Hedging Strategies. Our results of operations and operating cash flows are also affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2008, our oil and natural gas derivative instruments were comprised of futures, swaps and collars. These instruments generally consist of (i) New York Mercantile Exchange ("NYMEX") -traded natural gas for Appalachian and Michigan production, (ii) Panhandle Eastern Pipeline ("PEPL") -based contracts for Northeastern Colorado ("NECO") production, (iii) Colorado Interstate Gas Index ("CIG") -based contracts for other Colorado production and (iv) NYMEX-based swaps for our Colorado oil production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the fixed put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

We enter into derivative instruments for our own and affiliate partnerships' production to protect against price declines in future periods.

With regard to our natural gas marketing activities, we enter into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market.

We believe our economic hedging strategies continue to be effective in achieving the risk management objectives for which they were intended.

The following table summarizes the estimated fair value of our oil and natural gas derivative positions as of:

	September 30, 2008	December 31, 2007
	(in thousands)	
Derivative assets (liabilities)		
Oil and gas sales activities:		
Fixed-price natural gas swaps	\$ 51,242	\$ -
Natural gas floors	-	105
Natural gas collars	26,258	2,969
Fixed-price oil swaps	(19,326)	(5,097)
	58,174	(2,023)
Natural gas marketing activities:		
Fixed-price natural gas swaps	207	649
Natural gas collars	3	-
	210	649
Estimated net fair value of derivative instruments	\$ 58,384	\$ (1,374)

In addition to including the gross assets and liabilities for derivative positions related to our share of oil and gas production, the above tables and our condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into as the managing general partner on behalf of our affiliate partnerships. Our condensed consolidated balance sheets include the fair value of derivatives and a corresponding net payable to the partnerships of \$12.9 million at September 30, 2008, and a \$1.5 million net receivable from the partnerships at December 31, 2007.

Index

The following table identifies the fair value of commodity based derivatives as classified in our condensed consolidated balance sheets.

	September 30, 2008	December 31, 2007
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	\$ 56,713	\$ 4,817
Other assets - long-term asset	26,921	193
	83,634	5,010
Fair value of derivatives - current liability	13,840	6,291
Fair value of derivatives - long term liability	11,410	93
	25,250	6,384
Net fair value of commodity based derivatives	\$ 58,384	\$ (1,374)

The following changes in the fair value of commodity based derivatives are reflected in the condensed consolidated statements of income:

Statement of operations line item	Realized	Three Months Ended September 30,		Unrealized
		2008	2007	
		(in thousands, gain/(loss))		
Oil and gas price risk management gain (loss), net (1)	\$ (2,752)	\$ 172,154	\$ 2,491	\$ 3,854
Sales from natural gas marketing activities	(1,570)	18,024	1,477	12
Cost of natural gas marketing activities	1	(19,151)	(108)	(87)

Statement of operations line item	Realized	Nine Months Ended September 30,		Unrealized
		2008	2007	
		(in thousands, gain/(loss))		
Oil and gas price risk management gain (loss), net (1)	\$ (20,517)	\$ 45,811	\$ 3,098	\$ 1,344
Sales from natural gas marketing activities	(3,367)	1,333	2,805	(1,256)
Cost of natural gas marketing activities	119	(1,773)	(331)	1,168

(1) Represents net realized and unrealized gain and loss on commodity based derivative instruments related to oil and gas sales.

5. FAIR VALUE MEASUREMENTS

As described above in Note 2, in September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. We adopted the provisions of SFAS No. 157 effective January 1, 2008.

Valuation hierarchy. SFAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Instruments included in Level 1 consist of our commodity derivatives for NYMEX-based natural gas swaps.

Index

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments included in Level 3 consist of our commodity derivatives for CIG and PEPL based natural gas swaps, oil swaps, oil and natural gas options, and physical sales and purchases.

Determination of fair value. We measure fair value based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We have evaluated the credit risk of our receivables from our counterparties using credit default swap values for each counterparty with the outstanding hedge positions for the appropriate time period to calculate the maximum exposure. We have evaluated our exposure and determined that it is immaterial. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of September 30, 2008:

	Level 1	Level 3 (in thousands)	Total
Assets:			
Commodity based derivatives	\$ 9,478	\$ 74,156	\$ 83,634
Liabilities:			
Commodity based derivatives	(324)	(24,926)	(25,250)
Net fair value of commodity based derivatives	\$ 9,154	\$ 49,230	\$ 58,384

The following table sets forth a reconciliation of our Level 3 fair value measurements:

	September 30, 2008	
	Three Months Ended	Nine Months Ended
	(in thousands)	
Fair value, beginning of period (1)	\$ (141,453)	\$ (2,368)
Total realized and unrealized gains or (losses):		

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Included in oil and gas price risk management gain, net	167,755	124,234
Included in sales from natural gas marketing activities	1,864	1,807
Included in cost of natural gas marketing activities	17	2,650
Purchases, issuances and settlements, net	21,047	(77,093)
Fair value, end of period	\$ 49,230	\$ 49,230

Total gains (losses) attributable to the change in unrealized (loss), relating to assets still held as of September 30, 2008:

Included in oil and gas price risk management gain, net	\$ 167,755	\$ 124,234
Included in sales from natural gas marketing activities	1,864	1,807
Included in cost of natural gas marketing activities	17	2,650
Total	\$ 169,636	\$ 128,691

(1) Derivative assets and liabilities are presented on a net basis.

Index

6. LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2008	December 31, 2007 (in thousands)
Credit facility	\$ 122,000	\$ 235,000
12% Senior notes due 2018, net of discount of \$2.7 million	200,294	-
Total long-term debt	\$ 322,294	\$ 235,000

Credit facility

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended last on July 18, 2008, dated as of November 4, 2005, with an activated commitment of \$300 million as of September 30, 2008. The credit facility, through a series of amendments, includes commitments from: Wachovia Bank N.A.; Bank of Oklahoma; Allied Irish Banks p.l.c.; Guaranty Bank, FSB; Royal Bank of Canada; The Royal Bank of Scotland, plc; Calyon New York Branch; Compass Bank; The Bank of Nova Scotia; and BMO Capital Markets Financing, Inc. The maximum allowable commitment under the current credit facility is \$400 million, of which we currently have bank commitments for \$300 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of .375% to .50% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus .5%. ABR borrowings are assessed an additional margin spread up to .625% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.375% to 2.125%, based upon the outstanding balance under the credit facility. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, (g) enter into transactions with our affiliates, (h) change the character of our business, (i) engage in hedging activities unless certain requirements are satisfied, (j) issue certain types of stock, and (k) make certain amendments to our organizational documents. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. In addition, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or working capital ratio, and (b) not to exceed a maximum leverage ratio.

As of September 30, 2008, we had drawn \$122 million from our credit facility compared to \$235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 4.8% as of September 30, 2008 compared to 7.1% as of December 31, 2007. Amounts outstanding under our credit facility are secured by substantially all of our properties. We were in compliance with all covenants at September 30, 2008, and expect to remain in compliance throughout 2008.

We are in the process of soliciting our bank syndicate and additional banks to increase our revolving bank credit facility borrowing base and related bank commitments by \$75 million to \$375 million. While we can make no assurances as to the success of this initiative, we remain encouraged by its progress to date. We expect to finalize this transaction in early November.

12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is \$203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The first payment was paid on August 15, 2008. The senior notes were issued at a price of 98.572% of the principal amount. In addition, we capitalized \$5.4 million in costs associated with the issuance of the debt which has been capitalized as a deferred loan cost. The original discount and the deferred loan costs are being amortized to interest expense over the term of the debt using the effective interest method.

Index

As a result of recent global financial market conditions, as of September 30, 2008 we estimate the fair value of the senior notes at approximately \$191 million or approximately 94% of par value. We determined this valuation based upon measurements of trading activity and quotes provided by brokers and traders active in the trading of the securities. The liability is recorded at unamortized, original issue discount.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) restrict dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. We were in compliance with all covenants as of September 30, 2008, and expect to remain in compliance throughout 2008.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of September 30, 2008, none of our subsidiaries were obligated as guarantors of our senior notes.

The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008 remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes, at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

In connection with the issuance of the notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for other freely tradable notes and to use commercially reasonable efforts to cause the registration statement to become effective on or prior to February 7, 2009. On April 24, 2008, we filed the related registration statement on Form S-4. The registration statement was declared effective May 23, 2008.

7. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells in the Appalachian Basin by January 2016. We have plans to drill over 35 of these wells in 2008. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of \$25,000 per undrilled well for a total contingent obligation of \$2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of September 30, 2008, we have drilled 14 wells pursuant to this agreement.

Index

In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, who is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to make a capital investment, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser. The agreement also provides for certain volume commitments to be obtained by December 31, 2012. Qualifying capital expenditures include the cost to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the commitments, we will be required to pay a deficiency payment of up to \$25 million. At this time, we expect to meet the commitments of this agreement.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of September 30, 2008, was approximately \$12.9 million. We have adequate liquidity to meet this obligation. During the nine months of 2008 and for 2007, we paid \$1.5 million and \$1.6 million, respectively, under this provision for the repurchase of partnership units.

Partnership Casualty Losses. As managing general partner of 33 partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

Drilling Rig Contracts. In order to secure the services for drilling rigs, we made commitments to the drilling contractors, which call for a minimum commitment of \$12,500 daily for a specified amount of time if we cease to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of \$40,680 daily for a specified amount of time for daily use of the drilling rigs. Commitments for these two separate contracts expire in August 2009 and July 2010. For the drilling rig commitment which expires in August 2009, we have sub-leased the drilling rig to an unrelated party and expect to incur no additional cost on such contract. As of September 30, 2008, we have an outstanding minimum commitment for \$5.3 million and an outstanding maximum commitment for \$19.4 million.

Royalty litigation. On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado (the "Droegemueller Action"). The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is \$5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships for which the Company is the managing general partner, were deposited in an escrow account on November 3, 2008. We have accrued as of September 30, 2008, and included in other accrued expenses in the accompanying condensed consolidated balance sheet, a related \$5.8 million litigation reserve. We believe that the amount accrued is adequate to satisfy this obligation. Notice of the settlement will be mailed to members of the class action suit in mid November 2008. The final settlement approval hearing is expected in the first quarter of 2009.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position or results of operations.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation, and other various benefits, including equity awards, retirement and termination benefits.

In the event of termination without cause or if an executive officer terminates employment for good reason, the executive officer is entitled to receive a payment in the amount of three times the sum of his highest base salary during the previous two years of employment immediately preceding the termination date and his highest bonus received during the same two year period. The executive officer is also entitled to (i) vesting of any unvested equity compensation, (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of a pro rata bonus amount. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

Index

Derivative Contracts. We are exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. We have had no counterparty default losses.

8. STOCK-BASED COMPENSATION

We maintain equity compensation plans for officers, certain key employees and non-employee directors. In accordance with the plans, awards may be issued in the form of stock options, stock appreciation rights and restricted stock. Through the date of this report, we have not issued any stock appreciation rights.

The following table provides a summary of the impact of our stock based compensation plans on the results of operations for the periods presented.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Total stock-based compensation expense (1)	\$ 2,293	\$ 628	\$ 5,239	\$ 1,652
Income tax benefit	(875)	(242)	(1,999)	(637)
Net income impact	\$ 1,418	\$ 386	\$ 3,240	\$ 1,015

(1) Nine month activity includes \$1.1 million related to the separation agreement with our former president. Three and nine month activity includes \$1.1 million related to the retirement agreement with our former chief executive officer.

Stock Option Awards. We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. There were no stock options awarded for the nine months ended September 30, 2008 and 2007.

The following table provides a summary of our stock option award activity for the nine months ended September 30, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2007	51,567	\$ 33.55	6.4	\$ 1.3
Exercised	(19,699)	30.66	-	0.6
Forfeited	(7,517)	44.95	-	-
Outstanding at September 30, 2008	24,351			