DENBURY RESOURCES INC
Form 10-Q
November 09, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2009

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission file number 1-12935

DENBURY RESOURCES INC.
(Exact name of Registrant as specified in its charter)

Delaware	**20-0467835**
(State or other jurisdictions of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5100 Tennyson Parkway Suite 1200 Plano, TX	**75024**
(Address of principal executive offices)	*(Zip code)*

Registrant s telephone number, including area code: **(972) 673-2000**

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). 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.

Class	Outstanding at October 31, 2009
Common Stock, $.001 par value	249,823,000

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except shares)

	September 30, 2009	December 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 21,689	$ 17,069
Accrued production receivable	91,477	67,805
Trade and other receivables, net of allowance of $409 and $377	77,454	80,579
Derivative assets	17,900	249,746
Current deferred tax assets	5,637	
Total current assets	214,157	415,199
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,468,060	3,386,606
Unevaluated	213,170	235,403
CO_2 properties, equipment and pipelines	1,422,981	899,542
Other	80,015	70,328
Less accumulated depletion, depreciation and impairment	(1,763,902)	(1,589,682)
Net property and equipment	3,420,324	3,002,197
Deposits on property under option or contract		48,917
Other assets	52,343	43,357
Goodwill	138,830	
Investment in Genesis	77,606	80,004
Total assets	$ 3,903,260	$ 3,589,674
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 188,420	$ 202,633
Oil and gas production payable	86,038	85,833
Derivative liabilities	74,614	
Deferred revenue Genesis	4,070	4,070
Deferred tax liability		89,024
Current maturities of long-term debt	4,698	4,507
Total current liabilities	357,840	386,067
Long-term liabilities		

Long-term debt Genesis	250,681	251,047
Long-term debt	945,380	601,720
Asset retirement obligations	47,149	43,352
Deferred revenue Genesis	16,796	19,957
Deferred tax liability	458,940	433,210
Derivative liabilities	12,496	
Other	23,319	14,253
Total long-term liabilities	1,754,761	1,363,539
Stockholders equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding		
Common stock, $.001 par value, 600,000,000 shares authorized; 250,082,892 and 248,005,874 shares issued at September 30, 2009 and December 31, 2008, respectively	250	248
Paid-in capital in excess of par	734,398	707,702
Retained earnings	1,060,923	1,139,575
Accumulated other comprehensive loss	(575)	(627)
Treasury stock, at cost, 278,986 and 446,287 shares at September 30, 2009 and December 31, 2008, respectively	(4,337)	(6,830)
Total stockholders equity	1,790,659	1,840,068
Total liabilities and stockholders equity	$ 3,903,260	$ 3,589,674

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues and other income				
Oil, natural gas and related product sales	$ 221,321	$ 402,108	$ 600,942	$ 1,128,548
CO_2 sales and transportation fees	3,659	3,471	9,708	9,705
Interest income and other	434	1,895	1,948	3,525
Total revenues	225,414	407,474	612,598	1,141,778
Expenses				
Lease operating expenses	83,300	85,308	241,908	228,134
Production taxes and marketing expenses	8,555	17,104	24,294	50,978
Transportation expense Genesis	1,906	2,231	6,143	5,623
CO_2 operating expenses	1,047	1,240	3,442	2,836
General and administrative	24,038	15,005	79,828	45,821
Interest, net of amounts capitalized of $20,872, $6,713, $48,699, and $19,524, respectively	9,859	10,906	36,960	23,988
Depletion, depreciation and amortization	53,525	56,324	177,145	160,896
Commodity derivative expense (income)	3,757	(62,007)	177,061	43,591
Abandoned acquisition costs		30,426		30,426
Total expenses	185,987	156,537	746,781	592,293
Equity in net income of Genesis	1,835	2,780	5,802	3,796
Income (loss) before income taxes	41,262	253,717	(128,381)	553,281
Income tax provision (benefit)				
Current income taxes	(6,160)	12,689	18,140	44,769
Deferred income taxes	20,537	83,480	(67,869)	163,909
Net income (loss)	$ 26,885	$ 157,548	$ (78,652)	$ 344,603
Net income (loss) per common share basic	$ 0.11	$ 0.64	$ (0.32)	$ 1.41
Net income (loss) per common share diluted	$ 0.11	$ 0.63	$ (0.32)	$ 1.36
Weighted average common shares outstanding				
Basic	246,795	244,426	246,156	243,604
Diluted	252,189	251,831	246,156	252,708

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flow from operating activities:		
Net income (loss)	$ (78,652)	$ 344,603
Adjustments needed to reconcile to net cash flow provided by operations:		
Depletion, depreciation and amortization	177,145	160,896
Deferred income taxes	(67,869)	163,909
Deferred revenue Genesis	(3,161)	(3,383)
Stock-based compensation	25,450	10,979
Non-cash fair value derivative adjustments	323,510	(17,048)
Founder s retirement compensation	6,350	
Other	5,601	(2,921)
Changes in assets and liabilities related to operations:		
Accrued production receivable	(23,672)	(10,620)
Trade and other receivables	2,609	(46,330)
Other assets	(210)	188
Accounts payable and accrued liabilities	38,757	9,069
Oil and gas production payable	205	24,385
Other liabilities	371	(956)
Net cash provided by operating activities	406,434	632,771
Cash flow used for investing activities:		
Oil and natural gas capital expenditures	(289,815)	(436,114)
Acquisitions of oil and natural gas properties	(197,534)	(4,262)
CO_2 capital expenditures, including pipelines	(543,536)	(211,917)
Net purchases of other assets	(10,967)	(20,703)
Net proceeds from sales of oil and gas properties and equipment	303,450	48,948
Other	2,012	6,371
Net cash used for investing activities	(736,390)	(617,677)
Cash flow from financing activities:		
Bank repayments	(606,000)	(222,000)
Bank borrowings	551,000	72,000
Income tax benefit from equity awards	2,713	17,362
Pipeline financing Genesis	493	225,311
Issuance of subordinated debt	389,827	
Issuance of common stock	10,595	11,687
Costs of debt financing	(10,080)	
Other	(3,972)	(4,251)

Net cash provided by financing activities	334,576	100,109
Net increase in cash and cash equivalents	4,620	115,203
Cash and cash equivalents at beginning of period	17,069	60,107
Cash and cash equivalents at end of period	$ 21,689	$ 175,310
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ 14,114	$ 10,435
Cash paid (refunded) for income taxes	(4,894)	70,349
Interest capitalized	48,699	19,524
Increase (decrease) in liabilities for capital expenditures	(54,830)	24,273

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE OPERATIONS
(In thousands)

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income (loss)	$ 26,885	$ 157,548	$ (78,652)	$ 344,603
Other comprehensive income, net of income tax:				
Change in fair value of interest rate lock derivative contracts designated as a hedge, net of tax of $-, $-, $- and $49, respectively				12
Interest rate lock derivative contracts reclassified to income, net of taxes of $11, $11, $32 and $573, respectively	17	16	52	934
Comprehensive income (loss)	$ 26,902	$ 157,564	$ (78,600)	$ 345,549

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. Unless indicated otherwise or the context requires, the terms we, our, us, Denbury or Compa refer to Denbury Resources Inc. and its subsidiaries. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2008. Any capitalized terms used but not defined in these Notes to Unaudited Condensed Consolidated Financial Statements have the same meaning given to them in the Form 10-K.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. In management s opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments (of a normal recurring nature) necessary to present fairly the consolidated financial position of Denbury as of September 30, 2009, the consolidated results of its operations for the three and nine month periods ended September 30, 2009 and 2008 and cash flows for the nine months ended September 30, 2009 and 2008. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter. We have evaluated events that occurred subsequent to September 30, 2009 through November 9, 2009, the financial statement issuance date.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner but also considers the impact on net income and common shares for the potential dilution from stock options, stock appreciation rights (SARs), non-vested restricted stock and any other convertible securities outstanding. For the three and nine month periods ended September 30, 2009 and 2008, there were no adjustments to net income (loss) for purposes of calculating diluted net income (loss) per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income (loss) per common share calculations for the three and nine month periods ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2009	2008	2009	2008
Weighted average common shares basic	246,795	244,426	246,156	243,604
Potentially dilutive securities:				
Stock options and SARs	4,006	6,035		7,439
Restricted stock	1,388	1,370		1,665
Weighted average common shares diluted	252,189	251,831	246,156	252,708

The weighted average common shares basic amount excludes 2,454,168 shares at September 30, 2009 and 2,242,699 shares at September 30, 2008, of non-vested restricted stock that is subject to future vesting over time. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income (loss) per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating weighted average common shares diluted during the three months ended September 30, 2009 and the three and nine months ended September 30, 2008, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following securities were not included in the computation of diluted net earnings per share as their effect would have been anti-dilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2009	2008	2009	2008
Stock options and SARs	3,654	1,028	10,813	1,011
Restricted stock	79		2,930	
Total	3,733	1,028	13,743	1,011

CO_2 Pipelines

CO_2 pipelines are used for transportation of CO_2 to our tertiary floods from our CO_2 source field located near Jackson, Mississippi. We are continuing expansion of our CO_2 pipeline infrastructure with several pipelines currently under construction. At September 30, 2009 and December 31, 2008, we had $870.4 million and $402.0 million of costs, respectively, related to pipeline construction in progress, recorded under CO_2 properties, equipment and pipelines in our Unaudited Condensed Consolidated Balance Sheets. Pipeline construction in progress increased during 2009 primarily due to ongoing construction of our Green Pipeline. These costs of CO_2 pipelines under construction were not being depreciated at September 30, 2009 or December 31, 2008. Depreciation will commence as each segment of pipeline is placed into service. Each pipeline is depreciated on a straight-line basis over its estimated useful life as determined for GAAP purposes, which ranges between 20 to 30 years.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized, but rather it is tested for impairment annually during the fourth quarter and also when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. In the case of Denbury, we have only one reporting unit. The fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, the recorded goodwill is impaired to its implied fair value with a charge to operating expense. We recorded goodwill during 2009 in conjunction with our Hastings Field acquisition (see Note 2, Acquisitions and Divestitures).

Recently Adopted Accounting Pronouncements

FASB Accounting Standards Codification™. In June 2009, the Financial Accounting Standards Board (FASB) introduced the FASB Accounting Standards Codification™ (FASC) as the new source of authoritative U.S. generally accepted accounting principles (GAAP) for nongovernmental entities. The Company applied the new guidance to our financial statements issued for the nine months ended September 30, 2009. This standard did not have any impact on the Company s financial position or results of operations.

Subsequent Events. In May 2009, the FASB issued guidance under the Subsequent Events topic of the FASC to establish accounting standards for events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The new guidance does not significantly change current practice but does require companies to disclose the date through which subsequent events were evaluated and whether or not that date was the date the financial statements were issued or available for issuance. The Company adopted the new guidance upon its issuance with no resulting impact on the Company s financial position or results of operations.

Business Combinations. In December 2007, the FASB issued guidance under the Business Combinations topic of the FASC to establish principles and requirements for how an acquirer recognizes and measures in its financial statements, the identifiable assets

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acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. The guidance also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. We adopted the new guidance on January 1, 2009 and applied the guidance to an acquisition that we made during the first quarter (see Note 2, Acquisitions and Divestitures).

Equity Method Accounting. In November 2008, the FASB issued guidance in the Investments - Equity Company and Joint Ventures topic of the FASC to clarify how the application of equity method accounting will be affected by newly issued guidance on business combinations and noncontrolling interests in consolidated financial statements. The new guidance clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and impairment. Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This guidance was effective January 1, 2009, applies prospectively and did not have any impact on our financial position or results of operations.

Noncontrolling Interests. In December 2007, the FASB issued guidance under Consolidations topic of the FASC which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest, and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The new guidance also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted this guidance on January 1, 2009 and, since we currently do not have any noncontrolling interests, the adoption did not have any impact on our financial position or results of operations.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued guidance under the Derivatives and Hedging topic of the FASC which requires entities that utilize derivative instruments to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit risk related contingent features contained within derivatives. The guidance also requires entities to disclose additional information about the amounts and location of derivatives within the financial statements, how the provisions of accounting guidance related to derivatives and hedging have been applied, and the impact that hedges have on an entity s financial position, financial performance, and cash flows. We adopted the disclosure requirement beginning January 1, 2009 (see Note 6, Derivative Instruments and Hedging Activities). The adoption of this statement did not have any impact on our financial position or results of operations.

Fair Value Measurements. In 2006, the FASB issued guidance which defined fair value, established a framework for measuring fair value and expanded disclosures about fair value measurements. In February 2008, the FASB delayed the effective date of the new guidance for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We adopted the new guidance on January 1, 2009. The adoption of this guidance did not have any impact on our financial position or results of operations.

In April 2009, the FASB issued new rules to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. The FASB enhanced its guidance under the Fair Value Measurements and Disclosures topic of the FASC to 1) determine fair value when the volume and level of activity for an asset or liability have significantly decreased and 2) identify transactions that are not orderly. The FASB issued guidance under the Financial Instruments topic of the FASC to enhance consistency in financial reporting by increasing the frequency of fair value disclosures. The FASB also issued guidance in the Investments Debt and Equity Securities topic of the FASC to provide additional guidance to create greater clarity and consistency in accounting for and presenting impairment losses on securities. The new guidance was effective for interim and annual periods ending after June 15, 2009. Although adoption of the guidance enhanced our interim financial statement disclosures, it did not have any impact on our financial position or results of operations.

In August 2009, the FASB issued guidance under the Fair Value Measurements and Disclosures topic of the FASC to provide additional guidance on measuring the fair value of liabilities. The new guidance was effective for the

Company on October 1, 2009 and did not have any impact on the Company s financial position or results of operations.

Recently Issued Accounting Pronouncements

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and allow companies to disclose their probable and possible reserves to investors. The

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current rules limit disclosure to only proved reserves. The new rules also require companies that have an audit performed on their reserves to report the independence and qualifications of the reserve auditor, and file reports when a third party reserve engineer is relied upon to prepare reserve estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value be calculated using an average price based upon the prior twelve-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. In September 2009, the FASB issued an exposure draft of a proposed accounting standard update to the Extractive Industries Oil and Gas topic of the FASC that would align the FASB s oil and gas reserve estimation and disclosure requirements with the new SEC rule revisions. As written, the proposed amendments would be effective for periods ending on or after December 31, 2009. We are currently evaluating the impact the new rules may have on our financial condition or results of operations.

Transfers of Financial Assets. In June 2009, the FASB issued guidance related to the accounting for transfers of financial assets. The guidance removes the concept of a qualifying special-purpose entity (QSPE) from FASC topic, Transfers and Servicing , creates a new unit of account definition that must be met for transfers of portions of financial assets to be eligible for sale accounting, clarifies the de-recognition criteria for a transfer to be accounted for as a sale, changes the amount of recognized gains or losses on the transfer of financial assets accounted for as a sale when beneficial interests are received by the transferor and introduces new disclosure requirements. The new guidance is effective for us beginning January 1, 2010. We do not anticipate the adoption will have a material impact on our financial condition or results of operations.

Consolidation of Variable Interest Entities. In June 2009, the FASB issued guidance to eliminate the exemption in the Consolidation topic of the FASC for QSPEs, introduce a new approach for determining who should consolidate a variable interest entity and change the requirement as to when it is necessary to reassess who should consolidate a variable interest entity. This standard is effective for us beginning January 1, 2010. We are currently evaluating the impact the new rule may have on our financial condition or results of operations.

Note 2. Acquisitions and Divestitures

Hastings Field Acquisition

During November 2006, we entered into an agreement with a subsidiary of Venoco, Inc., that gave us an option to purchase their interest in Hastings Field, a strategically significant potential tertiary flood candidate located near Houston, Texas. We exercised the purchase option prior to September 2008, and closed the acquisition during February 2009. As consideration for the option agreement, during 2006 through 2008, we made cash payments totaling $50 million which we recorded as a deposit. The purchase price of approximately $196 million, which was paid in cash, was determined as of January 1, 2009 (the effective date) with closing on February 2, 2009. The final closing adjustments were completed during the three months ended September 30, 2009. The final closing price, adjusted for interim net cash flows between the effective date and closing date of the acquisition (including minor purchase price adjustments), totaled $246.8 million.

Under the terms of the agreement, Venoco, Inc., the seller, retained a 2% override and a reversionary interest of approximately 25% following payout, as defined in the option agreement. The Hastings Field proved reserves were not included in the Company s year-end 2008 proved reserves. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline currently under construction and construction of field recycling facilities. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately $179 million prior to December 31, 2014 as follows: $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to inject at least an average of 50 MMcf/day of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90 day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field s proved reserves using a 20% discount rate, or

(2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate.

This acquisition of Hastings Field qualifies as a business under FASC Business Combinations topic. As such, we estimated the fair value of this property as of the acquisition date, as defined in the FASC is the date on which the acquirer obtains control of the

DENBURY RESOURCES INC.

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acquiree, which for this acquisition is February 2, 2009 (the closing date). The FASC Fair Value Measurements and Disclosures topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the exit price). The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions should not impact the measurement of fair value unless those assumptions are consistent with market participant views.

In applying these accounting principles, we estimated the fair value of these properties on the acquisition date to be approximately $105.6 million. This measurement resulted in the recognition of goodwill totaling $138.8 million. The FASC defines goodwill as an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. For this acquisition, goodwill is the excess of the cash paid to acquire the Hastings Field over the acquisition date estimated fair value. This resultant goodwill is due primarily to two factors. The first factor is the decrease in the NYMEX oil and natural gas futures prices between the effective date of January 1, 2009, which is the date at which the acquisition price was determined, and the acquisition date of February 2, 2009, which is the date at which the assets were valued for accounting purposes. The purchase agreement provided that the Hastings reserves be valued using the NYMEX oil and gas futures prices on the effective date of January 1, 2009. The second factor is the estimated fair value assigned to the estimated oil reserves recoverable through a CO_2 enhanced oil recovery (EOR) project. Denbury has one of the few known significant natural sources of CO_2 in the United States, and the largest known source east of the Mississippi river. This source of CO_2 that we own will allow Denbury to carry out CO_2 EOR activities in this field at a much lower cost than other market participants. However, FASC Fair Value Measurements and Disclosures topic does not allow entity-specific assumptions in the measurement of fair value. Therefore, we estimated the fair value of the oil reserves recoverable through CO_2 EOR using an estimated cost of CO_2 to other market participants. This assumption of a higher cost of CO_2 resulted in an estimated fair value of the projected CO_2 EOR reserves that would not have been economically viable and therefore no value has been assigned to undeveloped properties in this acquisition.

The fair value of Hastings Field was based on significant inputs not observable in the market, which FASC Fair Value Measurements and Disclosures topic defines as Level 3 inputs. Key assumptions include (1) NYMEX oil and natural gas futures (this input is observable), (2) projections of the estimated quantities of oil and natural gas reserves, (3) projections of future rates of production, (4) timing and amount of future development and operating costs, (5) projected cost of CO_2 to a market participant, (6) projected recovery factors and, (7) risk adjusted discount rates. The fair value of these properties was assigned to the assets and liabilities acquired, which included $105.6 million to evaluated properties in the full cost pool and net $2.4 million for land, oilfield equipment and other related assets. Denbury applies SEC full cost accounting rules, under which the acquisition cost of oil and gas properties are recognized on a cost center basis (country), of which Denbury has only one cost center (United States). The goodwill of $138.8 million was assigned to this single reporting unit. All of the goodwill is deductible for tax purposes as property cost.

The transaction related costs (legal, accounting, due diligence, etc.) have been expensed. We have not presented any pro forma information for the acquired business as the pro forma effect was not material to our results of operations for the three or nine month periods ended September 30, 2009 or 2008.

Sale of Barnett Shale Assets

In May 2009, we entered into an agreement to sell 60% of our Barnett Shale natural gas assets to Talon Oil and Gas LLC, a privately held company, for $270 million (before closing adjustments). We closed on approximately three-quarters of the sale in June 2009 and closed on the remainder of the sale in July 2009. Net proceeds were $259.8 million (after preliminary closing adjustments, and net of $8.1 million for natural gas swaps transferred in the sale). The agreement has an effective date of June 1, 2009, and consequently operating net revenues after June 1, net of capital expenditures, along with any other purchase price adjustments, were adjustments to the selling price. We did not record a gain or loss on the sale in accordance with the full cost method of accounting. We have not presented pro forma information for the disposal as the pro forma effect was not material.

Note 3. Asset Retirement Obligations

In general, our future asset retirement obligations relate to future costs associated with plugging and abandonment of our oil, natural gas and CO_2 wells, removal of equipment and facilities from leased acreage and land restoration. The fair value of a liability for an asset retirement is recorded in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset.

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The following table summarizes the changes in our asset retirement obligations for the nine months ended September 30, 2009.

In thousands		Nine Months Ended September 30, 2009
Balance, beginning of period	$	45,064
Liabilities incurred and assumed during period		3,085
Revisions in estimated retirement obligations		1,640
Liabilities settled during period		(2,930)
Accretion expense		2,460
Sales		(1,008)
Balance, end of period	$	48,311

At September 30, 2009 and December 31, 2008, $1.2 million and $1.7 million, respectively, of our asset retirement obligation was classified in Accounts payable and accrued liabilities under current liabilities in our Unaudited Condensed Consolidated Balance Sheets. Liabilities incurred during the nine month period ended September 30, 2009 are primarily related to the Hastings Field acquisition and sales during the period are primarily related to the Barnett Shale natural gas assets (see Note 2, Acquisitions and Divestitures). We hold cash and liquid investments in escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts were $7.5 million at September 30, 2009 and $7.4 million at December 31, 2008, respectively, and are included in Other assets in our Unaudited Condensed Consolidated Balance Sheets.

Note 4. Notes Payable and Long-Term Indebtedness

In thousands		September 30, 2009		December 31, 2008
9.75% Senior Subordinated Notes due 2016	$	426,350	$	
Discount on Senior Subordinated Notes due 2016		(27,495)		
7.5% Senior Subordinated Notes due 2015		300,000		300,000
Premium on Senior Subordinated Notes due 2015		535		599
7.5% Senior Subordinated Notes due 2013		225,000		225,000
Discount on Senior Subordinated Notes due 2013		(680)		(826)
NEJD financing Genesis		171,408		173,618
Free State financing Genesis		79,336		76,634
Senior bank loan		20,000		75,000
Capital lease obligations Genesis		3,978		4,544
Capital lease obligations		2,327		2,705
Total		1,200,759		857,274
Less current obligations		4,698		4,507
Long-term debt and capital lease obligations	$	1,196,061	$	852,767

Issuance of 9.75% Senior Subordinated Notes due 2016

On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (2016 Notes). The 2016 Notes, which carry a coupon rate of 9.75%, were sold at a discount (92.816% of par), which equates to an effective yield to maturity of approximately 11.25%. The net proceeds of $381.4 million were used to repay most of our then-outstanding borrowings under our bank credit facility, which increased from the December 31, 2008 balance, primarily associated with the funding of the Hastings Field acquisition (see Note 2, Acquisitions and Divestitures). In conjunction with this debt offering we amended our bank credit facility in early February 2009, which, among other things, allowed us to issue these senior subordinated notes.

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In June 2009, we issued an additional $6.35 million of 2016 Notes to our founder, Gareth Roberts, as part of a Founder s Retirement Agreement. In connection with this issuance, we recorded compensation expense of $6.35 million in General and administrative expense in our Unaudited Condensed Consolidated Statement of Operations during the second quarter.

The 2016 Notes mature on March 1, 2016, and interest on the 2016 Notes is payable March 1 and September 1 of each year beginning on September 1, 2009. We may redeem the 2016 Notes in whole or in part at our option beginning March 1, 2013, at the following redemption prices: 104.875% after March 1, 2013, 102.4375% after March 1, 2014, and 100%, after March 1, 2015. In addition, we may at our option, redeem up to an aggregate of 35% of the 2016 Notes before March 1, 2012 at a price of 109.75%. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2016 Notes are not subject to any sinking fund requirements. All of our significant subsidiaries fully and unconditionally guarantee this debt.

Senior Bank Loan

To clarify that Denbury entities are allowed to guarantee obligations of other Denbury entities, in May 2009 we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our Senior Bank Loan, to explicitly permit these guarantees and waive any possible previous technical violations of this provision.

In June 2009 we again amended our Senior Bank Loan agreement in connection with the sale of our Barnett Shale natural gas properties and (i) reduced our borrowing base from $1.0 billion to $900 million and (ii) allowed for an additional percentage of our forecasted production to be hedged through June 30, 2009. The amendment did not impact the banks commitment amount, which remains at $750 million.

On November 1, 2009, Denbury and Encore Acquisition Company announced that they had entered into a definitive merger agreement pursuant to which Denbury will acquire Encore in a stock and cash transaction. Denbury received a commitment letter from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A., subject to certain funding conditions, for a proposed new $1.6 billion senior secured revolving credit facility with a term of four years, the proceeds from which would be used to pay down our existing Senior Bank Loan and other related financing. See Management s Discussion and Analysis of Financial Condition and Result of Operations Overview Definitive Merger Agreement to Acquire Encore Acquisition Company for further details.

Note 5. Related Party Transactions Genesis

Interest in and Transactions with Genesis

Denbury s subsidiary, Genesis Energy, LLC, is the general partner of, and together with Denbury s other subsidiaries, owns an aggregate 12% interest in Genesis Energy, L.P. (Genesis), a publicly traded master limited partnership. Genesis business is focused on the mid-stream segment of the oil and natural gas industry in the Gulf Coast area of the United States, and its activities include gathering, marketing and transportation of crude oil and natural gas, refinery services, wholesale marketing of CO_2, and supply and logistic services.

We account for our 12% ownership in Genesis under the equity method of accounting as we have significant influence over the limited partnership; however, our control is limited under the limited partnership agreement and therefore we do not consolidate Genesis. Denbury received cash distributions from Genesis of $8.2 million and $4.9 million during the nine months ended September 30, 2009 and 2008, respectively. We also received $0.2 million and $0.1 million during the nine months ended September 30, 2009 and 2008, respectively, as directors fees for certain officers of Denbury that are board members of Genesis. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, LLC.

Incentive Compensation Agreement

In late December 2008, our subsidiary, Genesis Energy, LLC, entered into agreements with three members of Genesis management, for the purpose of providing them incentive compensation, which agreements make them Class B Members in Genesis Energy, LLC. The compensation agreements provide Genesis management with the ability to earn up to an approximate aggregate 17% interest in the incentive distributions that Genesis Energy, LLC receives (commencing in 2009) from Genesis. The percentage

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interest in the incentive distribution earned in any given period can vary based upon the Cash Available Before Reserves (CABR) per unit as generated by Genesis (excluding any transactions between Genesis and the Company) over each of the three individual s base amount of CABR per unit as stated in their compensation agreement, subject to vesting and other requirements. As the amount of CABR per unit increases, the members share of the incentive distributions increases, up to a maximum aggregate 17% in any given period.

The amount payable under the award in the event of an employee termination is the present value of the member s share of forecasted incentive distributions assuming the then current level of distributions continue into perpetuity. The award agreement dictates that the member s share of future incentive distributions be discounted back to the payment date using a discount rate equal to the current distribution yield of market comparable general partners of master limited partnerships.

The awards vest 25% on each anniversary grant date. The awards are mandatorily redeemable upon termination of employment or change in control and require the membership interests of the holders of the awards to be redeemed for cash (or in certain circumstances Genesis limited partnership units) by Genesis Energy, LLC. The estimated fair value of these awards is measured each reporting period and recorded as a liability to the extent vested. Changes in the liability are recorded as compensation expense in General and administrative expenses in our Unaudited Condensed Consolidated Statement of Operations. We use the graded attribution method to recognize the share-based compensation expense associated with these awards. As of September 30, 2009, we had approximately $8.8 million recorded as a liability for these awards in our Unaudited Condensed Consolidated Balance Sheet. We recorded approximately $3.6 million in the three month period ended September 30, 2009 and $9.1 million in the nine month period ended September 30, 2009 in General and administrative expenses on our Unaudited Condensed Consolidated Statement of Operations, of which $0.1 million and $0.3 million in the three and nine month periods, respectively, relate to cash payments made under these awards and $3.5 million and $8.8 million, respectively, are associated with the fair value of the award.

The fair value of these awards is estimated using a discounted cash flow analysis which includes assumptions regarding a number of variables, including Genesis management s estimates of future CABR generated by Genesis, the distribution yield of market comparable publicly-traded general partners of master limited partnerships and a discount rate which considers the risk of forecasted items being realized, the time value of money and the risk of nonperformance by Denbury. The fair value estimation does not represent the contractual amounts payable under these awards at a particular reporting date.

NEJD Pipeline and Free State Pipeline Transactions

On May 30, 2008, we closed on two transactions with Genesis involving our Northeast Jackson Dome (NEJD) pipeline system and Free State Pipeline, which included a long-term transportation service agreement for the Free State Pipeline and a 20-year financing lease for the NEJD system. We have recorded both of these transactions as financing leases. At September 30, 2009, we have recorded $171.4 million for the NEJD financing and $79.3 million for the Free State financing as debt, $3.2 million of which was recorded in current liabilities on our Unaudited Condensed Consolidated Balance Sheet. At December 31, 2008, we had $173.6 million for the NEJD pipeline and $76.6 million for the Free State Pipeline recorded as debt, of which $3.0 million was included in current liabilities in our Unaudited Condensed Consolidated Balance Sheet (see Note 4, Notes Payable and Long-Term Indebtedness).

Oil Sales and Transportation Services

We utilize Genesis trucking services and common carrier pipeline to transport certain of our crude oil production to sales points where it is sold to third party purchasers. We expensed $1.9 million and $2.2 million for these transportation services during the three months ended September 30, 2009 and 2008, respectively, and $6.1 million and $5.6 million during the nine months ended September 30, 2009 and 2008, respectively.

Transportation Leases

We have pipeline transportation agreements with Genesis to transport our crude oil from certain of our fields in Southwest Mississippi, and to transport CO_2 from our main CO_2 pipeline to Brookhaven Field for our tertiary operations. We have accounted for these agreements as capital leases. At September 30, 2009 and December 31, 2008, we had $4.0 million and $4.5 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Unaudited Condensed Consolidated Balance Sheets.

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CO_2 Volumetric Production Payments

During 2003 through 2005, we sold 280.5 Bcf of CO_2 to Genesis under three separate volumetric production payment agreements. We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and recognize such revenue as CO_2 is delivered under the volumetric production payments. At September 30, 2009 and December 31, 2008, $20.9 million and $24.0 million, respectively, was recorded as deferred revenue, of which $4.1 million was included in current liabilities at both September 30, 2009 and December 31, 2008. We recognized deferred revenue of $1.2 million for both the three month periods ended September 30, 2009 and 2008, respectively, and $3.2 million and $3.4 million during the nine month periods ended September 30, 2009 and 2008, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with transporting CO_2 to their industrial customers for a fee of approximately $0.20 per Mcf of CO_2. For these services, we recognized revenues of $1.5 million for both the three months ended September 30, 2009 and 2008, respectively, and $4.0 million and $4.1 million for the nine months ended September 30, 2009 and 2008, respectively.

Note 6. Derivative Instruments and Hedging Activities

Oil and Natural Gas Derivative Contracts

We do not apply hedge accounting treatment to our oil and natural gas derivative contracts and therefore the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts are shown under Commodity derivative expense (income) in our Unaudited Condensed Consolidated Statements of Operations.

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps.

As a result of the recent economic conditions, in the fall of 2008 we entered into oil derivative contracts for 2009 in order to protect our liquidity in the event that commodity prices continued to decline. Since that time, we have entered into oil and natural gas commodity contracts each quarter for a portion of our forecasted production in the following year. We have entered into these contracts to provide us a more predictable cash flow for the following year to protect our capital investment program in that subsequent year.

At September 30, 2009, our oil and natural gas derivative contracts were recorded at their fair value, which was a net liability of $69.2 million. All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our Senior Bank Loan.

The following is a summary of Commodity derivative expense (income) included in our Unaudited Condensed Consolidated Statements of Operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2009	2008	2009	2008
Receipt (payment) on settlements of derivative contracts oil	$ 18,527	$ (11,186)	$ 146,365	$ (30,709)
Receipt (payment) on settlements of derivative contracts gas		(12,886)		(30,005)
Fair value adjustments to derivative contracts income (expense)	(22,284)	86,079	(323,426)	17,123

Commodity derivative income (expense)	$ (3,757)	$ 62,007	$ (177,061)	$ (43,591)

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Fair Value of Crude Oil Derivative Contracts Not Classified as Hedging Instruments:

	NYMEX Contract Prices Per Bbl				Estimated Fair Value Asset (Liability)	
			Collar Prices		September 30,	December 31,
Type of Contract and Period	Bbls/d	Swap Price	Floor	Ceiling	2009	2008
					(In thousands)	
Collar Contracts						
Oct. 2009 - Dec. 2009	30,000		$75.00	$115.00	$ 17,900	$249,746
April 2010 - June 2010	5,000		50.00	76.00	(2,995)	
April 2010 - June 2010	10,000		50.00	73.15	(7,186)	
April 2010 - June 2010	5,000		50.00	76.40	(2,916)	
April 2010 - June 2010	5,000		50.00	74.30	(3,343)	
July 2010 - Sept. 2010	2,500		55.00	80.10	(1,095)	
July 2010 - Sept. 2010	10,000		55.00	80.00	(4,416)	
July 2010 - Sept. 2010	7,500		60.00	80.40	(2,320)	
July 2010 - Sept. 2010	5,000		60.00	81.05	(1,430)	
Oct. 2010 - Dec. 2010	5,000		60.00	89.70	(594)	
Oct. 2010 - Dec. 2010	10,000		60.00	89.50	(1,238)	
Oct. 2010 - Dec. 2010	5,000		60.00	89.00	(682)	
Oct. 2010 - Dec. 2010	5,000		60.00	88.75	(714)	
Swap Contracts						
Jan. 2010 - March 2010	6,667	$52.50			(11,687)	
Jan. 2010 - March 2010	3,333	52.20			(5,930)	
Jan. 2010 - March 2010	5,000	52.10			(8,941)	
Jan. 2010 - March 2010	5,000	50.90			(9,469)	
Jan. 2010 - March 2010	5,000	51.45			(9,227)	

Fair Value of Natural Gas Derivative Contracts Not Classified as Hedging Instruments:

	NYMEX Contract Prices Per MMBtu		Estimated Fair Value Liability	
			September 30,	December 31,
Type of Contract and Period	MMBtu/d	Swap Price	2009	2008
			(In thousands)	
Swap Contracts				
Jan. 2010 - Dec. 2010	39,000	$5.67	$(7,289)	$
Jan. 2011 - Dec. 2011	10,000	6.27	(1,977)	
Jan. 2011 - Dec. 2011	10,000	6.25	(2,026)	
Jan. 2011 - Dec. 2011	7,000	6.16	(1,635)	

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Additional Disclosures about Derivative Instruments:

At September 30, 2009 and December 31, 2008, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) September 30, 2009	December 31, 2008
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative Asset			
Crude Oil contracts	Derivative assets - current	$ 17,900	$ 249,746
Derivative Liability			
Crude Oil contracts	Derivative liability - current	(70,955)	
Natural Gas contracts	Derivative liability - current	(3,659)	
Crude Oil contracts	Derivative liability - long-term	(3,228)	
Natural Gas contracts	Derivative liability - long-term	(9,268)	
Total derivatives not designated as hedging instruments		$ (69,210)	$ 249,746

For the three and nine months ended September 30, 2009 and 2008, the net effect on income of derivative financial instruments was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Amount of Gain/(Loss) Recognized in Income For Three Months Ended September 30, 2009	2008	Amount of Gain/(Loss) Recognized in Income For Nine Months Ended September 30, 2009	2008
		(In thousands)			
Derivatives not designated as hedging instruments:					

Commodity Contracts					
Crude Oil Contracts	Commodity derivative income (expense)	$ (2,323)	$ 11,466	$ (159,664)	$ (12,976)
Natural Gas Contracts	Commodity derivative income (expense)	(1,434)	50,541	(17,397)	(30,615)
Total derivatives not designated as hedging instruments		$ (3,757)	$ 62,007	$ (177,061)	$ (43,591)

Note 7. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value.

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The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities as of the reporting date. During 2008 and the first nine months of 2009, we had no level 1 recurring measurements.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Instruments in this category include non-exchange-traded oil and natural gas derivatives such as over-the-counter swaps. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts. We have measured nonperformance risk based upon credit default swaps or credit spreads. At September 30, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $2.8 million and $3.7 million, respectively, for estimated nonperformance risk.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2009 and December 31, 2008.

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
<u>September 30, 2009</u>				
Assets:				
Oil derivative contracts	$	$ 17,900	$	$ 17,900
Liabilities:				
Oil and natural gas derivative contracts		(87,110)		(87,110)
Total	$	$ (69,210)	$	$ (69,210)
<u>December 31, 2008</u>				
Assets:				
Oil derivative contracts	$	$ 249,746	$	$ 249,746
Total	$	$ 249,746	$	$ 249,746

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Unaudited Condensed Consolidated Financial Statements.

	September 30, 2009		December 31, 2008	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
9.75% Senior Subordinated Notes due 2016	$398,855	$453,000	$	$
7.5% Senior Subordinated Notes due 2015	300,535	298,000	300,599	213,000
7.5% Senior Subordinated Notes due 2013	224,320	225,000	224,174	171,000
Senior Bank Loan	20,000	18,500	75,000	64,000

The fair values of our senior subordinated notes are based on quoted market prices. The carrying value of our Senior Bank Loan is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We adjusted the estimated fair value measurement of our Senior Bank Loan for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $1.5 million and $11.0 million at September 30, 2009 and December 31, 2008, respectively, and was determined utilizing industry credit default swaps. We have other financial instruments consisting primarily of cash, cash equivalents, short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 8. Condensed Consolidating Financial Information

Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc. s subsidiaries other than minor subsidiaries, except that with respect to our $225 million of 7.5% Senior Subordinated Notes due 2013, Denbury Resources Inc. and Denbury Onshore, LLC are co-obligors. Except as noted in the foregoing sentence, Denbury Resources Inc. is the sole issuer and Denbury Onshore, LLC is a subsidiary guarantor. The results of our equity interest in Genesis are reflected through the equity method by one of our subsidiaries, Denbury Gathering & Marketing. Each subsidiary guarantor and the subsidiary co-obligor are 100% owned, directly or indirectly, by Denbury Resources Inc. The following is condensed consolidating financial information for Denbury Resources Inc., Denbury Onshore, LLC, and subsidiary guarantors:

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Balance Sheets

	September 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 454,421	$ 211,151	$ 18,440	$ (469,855)	$ 214,157
Property and equipment		3,278,493	141,831		3,420,324
Investment in subsidiaries (equity method)	1,296,596	24,315	1,294,644	(2,537,949)	77,606
Other assets	747,676	180,361	2,555	(739,419)	191,173
Total assets	$ 2,498,693	$ 3,694,320	$ 1,457,470	$ (3,747,223)	$ 3,903,260
Liabilities and Stockholders Equity					
Current liabilities	$ 8,644	$ 668,979	$ 150,072	$ (469,855)	$ 357,840
Long-term liabilities	699,390	1,783,988	10,802	(739,419)	1,754,761
Stockholders equity	1,790,659	1,241,353	1,296,596	(2,537,949)	1,790,659
Total liabilities and stockholders equity	$ 2,498,693	$ 3,694,320	$ 1,457,470	$ (3,747,223)	$ 3,903,260

	December 31, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 458,051	$ 408,940	$ 14,992	$ (466,784)	$ 415,199
Property and equipment		2,973,947	28,250		3,002,197
Investment in subsidiaries (equity method)	1,371,347	24,901	1,368,759	(2,685,003)	80,004
Other assets	312,239	89,471	899	(310,335)	92,274
Total assets	$ 2,141,637	$ 3,497,259	$ 1,412,900	$ (3,462,122)	$ 3,589,674

Liabilities and Stockholders Equity					
Current liabilities	$ 970	$ 810,476	$ 41,405	$ (466,784)	$ 386,067
Long-term liabilities	300,599	1,373,127	148	(310,335)	1,363,539
Stockholders equity	1,840,068	1,313,656	1,371,347	(2,685,003)	1,840,068
Total liabilities and stockholders equity	$ 2,141,637	$ 3,497,259	$ 1,412,900	$ (3,462,122)	$ 3,589,674

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Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 16,247	$ 225,415	$ (1)	$ (16,247)	$ 225,414
Expenses	17,763	182,412	2,059	(16,247)	185,987
Income (loss) before the following:	(1,516)	43,003	(2,060)		39,427
Equity in net earnings of subsidiaries	28,401	212	30,613	(57,391)	1,835
Income before income taxes	26,885	43,215	28,553	(57,391)	41,262
Income tax provision		14,225	152		14,377
Net income	$ 26,885	$ 28,990	$ 28,401	$ (57,391)	$ 26,885

	Three Months Ended September 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,625	$ 407,461	$ 13	$ (5,625)	$ 407,474
Expenses	5,745	155,578	839	(5,625)	156,537
Income (loss) before the following:	(120)	251,883	(826)		250,937
Equity in net earnings of subsidiaries	157,658	362	159,209	(314,449)	2,780
Income before income taxes	157,538	252,245	158,383	(314,449)	253,717
Income tax provision (benefit)	(10)	95,454	725		96,169
Net income	$ 157,548	$ 156,791	$ 157,658	$ (314,449)	$ 157,548

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Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations (continued)

	Nine Months Ended September 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 42,967	$ 612,597	$ 1	$ (42,967)	$ 612,598
Expenses	46,816	735,599	7,333	(42,967)	746,781
Loss before the following:	(3,849)	(123,002)	(7,332)		(134,183)
Equity in net earnings of subsidiaries	(74,803)	628	(67,180)	147,157	5,802
Loss before income taxes	(78,652)	(122,374)	(74,512)	147,157	(128,381)
Income tax provision (benefit)		(50,020)	291		(49,729)
Net loss	$ (78,652)	$ (72,354)	$ (74,803)	$ 147,157	$ (78,652)

	Nine Months Ended September 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 16,875	$ 1,141,745	$ 33	$ (16,875)	$ 1,141,778
Expenses	17,236	589,461	2,471	(16,875)	592,293
Income (loss) before the following:	(361)	552,284	(2,438)		549,485
Equity in net earnings of subsidiaries	344,933	540	348,301	(689,978)	3,796
Income before income taxes	344,572	552,824	345,863	(689,978)	553,281
Income tax provision (benefit)	(31)	207,779	930		208,678
Net income	$ 344,603	$ 345,045	$ 344,933	$ (689,978)	$ 344,603

Condensed Consolidating Statements of Cash Flows

Denbury Resources Inc. (Parent) has no independent assets or operations. Denbury Onshore, LLC is our operating subsidiary. Cash flow activity of Denbury Resources Inc. consists of intercompany loans between Denbury Resources Inc. and Denbury Onshore, LLC to service the parent company issued debt. This intercompany cash flow activity is eliminated in consolidation. Cash flow activity of Denbury Onshore, LLC combined with the other guarantor subsidiaries is presented in our Unaudited Condensed Consolidated Statements of Cash Flows.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

	Nine Months Ended September 30, 2009				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$	$ 406,192	$ 242	$	$ 406,434
Cash flow from investing activities	(409,293)	(736,390)		409,293	(736,390)
Cash flow from financing activities	409,293	334,576		(409,293)	334,576
Net increase in cash		4,378	242		4,620
Cash, beginning of period	24	16,898	147		17,069
Cash, end of period	$ 24	$ 21,276	$ 389	$	$ 21,689

	Nine Months Ended September 30, 2008				
In thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ (10)	$ 622,674	$ 10,107	$	$ 632,771
Cash flow from investing activities	(25,344)	(612,064)	(5,613)	25,344	(617,677)
Cash flow from financing activities	25,344	100,109		(25,344)	100,109
Net increase (decrease) in cash	(10)	110,719	4,494		115,203
Cash, beginning of period	34	58,343	1,730		60,107
Cash, end of period	$ 24	$ 169,062	$ 6,224	$	$ 175,310

Note 9. Subsequent Event

On October 31, 2009, the Company entered into a definitive merger agreement pursuant to which the Company will acquire Encore Acquisition Company (NYSE: EAC) (Encore). Under the terms of the definitive agreement, Encore stockholders will receive $50.00 per share for each share of Encore common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock subject to both an election feature and a collar mechanism on the stock portion of the consideration. Consummation of the merger is subject to customary conditions. See *Management s Discussion and Analysis of Financial Condition and Results of Operations Overview - Definitive Merger Agreement to Acquire Encore Acquisition Company* for further details on the terms of this agreement.

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DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Form 10-K for the year ended December 31, 2008, along with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of this report, along with Forward-Looking Information at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are a growing independent oil and natural gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, own the largest carbon dioxide (CO_2) reserves east of the Mississippi River used for tertiary oil recovery, hold interests in the Barnett Shale play near Fort Worth, Texas, and properties onshore in Louisiana, Alabama and Southeast Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, with our most significant emphasis relating to tertiary recovery. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have four primary field offices located in Laurel, Mississippi; McComb, Mississippi; Jackson, Mississippi; and Pearland, Texas.

Third Quarter Operating Highlights. During the third quarter of 2009, we recorded net income of $26.9 million, or $0.11 per basic common share, as compared to net income of $157.5 million, or $0.64 per basic common share, in the comparative third quarter of 2008. The reduction in net income between the periods is primarily due to lower oil and natural gas commodity prices coupled with reduced natural gas production due to the sale of 60% of the Company s Barnett Shale natural gas assets in mid-2009, and a $108.4 million net decrease in the fair value changes in commodity derivative contracts in the comparative periods.

Oil and natural gas production for the third quarter of 2009 averaged 42,659 BOE/d, a 10% increase from third quarter 2008 production, after adjusting for the 2009 sale of 60% of the Company s Barnett Shale natural gas assets. The increase over the prior year third quarter period was primarily due to a 23% increase in tertiary oil production and production from Hastings Field (2,083 BOE/d in the current year quarter), which we acquired in February 2009, offset in part by the expected decrease in our non-tertiary Mississippi production. The non-tertiary Mississippi production decline was primarily from the Selma Chalk natural gas production as a result of limited drilling activity in 2009 and non-tertiary Heidelberg oil as additional areas of the field were shut-in in order to expand the tertiary flooding to those areas. On a sequential quarterly basis, our oil and natural gas production decreased 4%, primarily due to the decreases in non-tertiary Mississippi production offset in part by a slight increase in our tertiary production.

During the third quarter of 2009, our tertiary production averaged 24,347 Bbls/d, which included 829 Bbls/d from tertiary production response at Heidelberg Field. During the quarter, we also had strong production increases compared to the prior quarter, at Tinsley (averaging 3,558 Bbls/d, a 5% increase), Soso (averaging 2,813 Bbls/d, a 9% increase), Lockhart Crossing (averaging 882 Bbls/d, a 26% increase), and Cranfield (averaging 572 Bbls/d, a 69% increase). These increases were offset in part by planned downtime at Mallalieu Field for facility expansion during the quarter, and we also expanded our facilities at Tinsley Field, earlier than originally planned, reducing the production rate of growth at that field during the third quarter.

In addition to the decrease in our third quarter 2009 production due to the Barnett Shale sale, our oil and natural gas revenues were 45% lower in the third quarter of 2009 than in the prior year third quarter, as the average price we received for our production on a per BOE basis was 41% lower in the current year period. Since over 80% of our production is oil, oil prices have a much larger impact on our revenues than natural gas prices. NYMEX oil prices moved from $44.60 per barrel at December 31, 2008 to as low as $34.00 per barrel in mid-February 2009, up to $49.66 per barrel at March 31, 2009, $69.89 per barrel at June 30, 2009 and $70.61 per barrel at September 30, 2009. NYMEX natural gas prices have decreased from year-end 2008, falling from $5.62 per Mcf at December 31, 2008 to

$3.78 per Mcf at March 31, 2009, $3.84 per Mcf at June 30, 2009, then recovering slightly, and ending the third quarter 2009 at $4.84 per Mcf.

Cash settlements received on our commodity derivative contracts, which are not included in our oil and natural gas revenues, were $18.5 million in the third quarter of 2009, as compared to payments of $24.1 million in the third quarter of 2008, the prior year amount comprised of payments made of $11.2 million on oil derivative contracts and $12.9 million on natural gas derivative contracts.

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DENBURY RESOURCES INC.

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Definitive Merger Agreement to Acquire Encore Acquisition Company. On November 1, 2009, Denbury and Encore Acquisition Company (NYSE: EAC) (Encore) announced that they had entered into a definitive merger agreement pursuant to which Denbury will acquire Encore in a stock and cash transaction valued at approximately $4.5 billion, including the assumption of debt and the value of the minority interest in Encore Energy Partners LP (NYSE: ENP) (Encore MLP). The combined company will continue to be known as Denbury Resources Inc. and will be headquartered in Plano, Texas.

The Agreement and Plan of Merger by and between Denbury and Encore dated October 31, 2009 (the Merger Agreement) was unanimously approved by the boards of directors of both Denbury and Encore. The Merger Agreement contemplates a merger (the Merger) whereby Encore will be merged with and into Denbury, with Denbury surviving the Merger. The Merger is subject to the stockholders of each of Denbury and Encore approving the Merger, including approval by Denbury s stockholders of the issuance of Denbury common stock to be used as Merger consideration.

Under the agreement, Encore stockholders will receive $50.00 per share for each share of Encore common stock, comprised of $15.00 in cash and $35.00 in Denbury common stock subject to both an election feature and a collar mechanism on the stock portion of the consideration as set forth in more detail below.

Merger Agreement

Exchange Ratio

In calculating the exchange ratio range for the collar mechanism, the Denbury common stock was initially valued at $15.10 per share. The collar mechanism is limited to a 12% upward or downward movement in the Denbury share price. The final number of Denbury shares to be issued will be adjusted based on the volume weighted average price of Denbury common stock on the NYSE for the 20 day trading period ending on the second day prior to closing. Based on this mechanism, if Denbury stock trades between $13.29 and $16.91, the Encore stockholders will receive between 2.0698 and 2.6336 shares of Denbury common stock for each of their shares of Encore common stock, but not higher or lower than these share amounts if Denbury common stock trades outside this range. If Denbury common stock trades outside of this range, the value of the shares of Denbury received will represent either more or less than $35 per share.

Encore stockholders will also have an option to elect to receive all stock or all cash, subject to a proration feature, such that if Denbury stock trades within this range, the overall mix of consideration will be 70% Denbury common stock and 30% cash in the aggregate. Subject to proration, Encore stockholders electing to receive all cash will receive $50 per share in cash, and Encore stockholders electing to receive only Denbury common stock will receive for each Encore share between 2.9568 and 3.7622 shares of Denbury common stock. In addition, upon completion of the Merger, all Encore stock options will fully vest and their value will be paid in cash. All Encore restricted stock will vest and each holder will have the opportunity to make the same elections as other holders of Encore common stock as described above, except for shares of Encore restricted stock granted as a 2009 bonus pursuant to the Encore annual incentive program, which will be converted into restricted shares of Denbury common stock.

Covenants

The Merger Agreement contains customary covenants by each party to the Merger Agreement. Such covenants include, among others, covenants that both Denbury and Encore will operate their respective businesses in the ordinary course and in a manner consistent with past practices, subject to limited exceptions, and covenants by both Denbury and Encore that their respective boards of directors not change their recommendations to the stockholders of each of them to vote in favor of the Merger, subject to exceptions specified in the Merger Agreement. Encore has also agreed not to solicit or initiate discussions with third parties regarding other proposals to acquire Encore and to certain restrictions on its ability to respond to any such proposal.

Conditions to Closing

Consummation of the Merger is subject to customary conditions, including, among others, (a) the approval of the stockholders of each of Denbury and Encore, (b) the absence of any material adverse effect, (c) the expiration or early termination of the applicable Hart-Scott-Rodino Act waiting period, (d) the absence of any order or injunction prohibiting the consummation of the Merger, (e) the effectiveness of the registration statement of Denbury filed on Form S-4, (f) the approval of the listing of the shares of Denbury common stock to be issued in the Merger on the New York Stock Exchange, (g) the accuracy of the parties respective representations and warranties as set forth in the Merger Agreement, subject, as to certain of the representations and warranties as specified in the Merger Agreement, to materiality, (h) the receipt of legal opinions stating, among other things, that the Merger will constitute a reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended, (i) the receipt of all approvals or reviews required by federal and state regulatory authorities and (j) financing.

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In connection with the Merger Agreement, Denbury received a commitment letter from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A., subject to certain funding conditions, for a proposed new $1.6 billion senior secured revolving credit facility with a term of four years and a $1.25 billion bridge facility that will be available to the extent Denbury does not secure alternate financing prior to the end of the bridge takedown period. The bridge facility, if drawn, will initially mature on the first anniversary of the closing of the Merger, at which time the maturity of any outstanding loans thereunder will be automatically extended to the seventh anniversary of the closing of the Merger, except to the extent they have been previously exchanged by the lender for exchange notes due on such seventh anniversary. The new debt financing will be used to pay the cash consideration in the Merger, repay amounts outstanding under Denbury s current $900 million revolving credit facility and potentially retire and replace $825 million of Encore s outstanding subordinated notes, all of which have a change of control put option at 101%, replace Encore s existing bank facility which has approximately $180 million currently drawn and outstanding, and for other fees and expenses. Denbury has also received a commitment from J. P. Morgan Securities Inc. and JP Morgan Chase Bank to fund a new $375 million senior secured revolving credit facility to replace an existing Encore MLP revolving loan facility should Denbury and Encore be unable to obtain a waiver of covenants and amendment to such loan facility to allow for the Merger. Fee letters executed in connection with the bank commitment letter provide for Denbury to pay up to approximately $50 million in fees if the loans do not close.

Termination

The Merger Agreement contains certain termination rights for both Denbury and Encore, including, among others, if the Merger is not completed by May 31, 2010. In the event of a termination of the Merger Agreement under certain circumstances, Encore may be required to pay Denbury a termination fee of either $60 million or $120 million, or Denbury may be required to pay Encore a termination fee of either $60 million, $120 million or $300 million, in each case depending on the circumstances of the termination. In addition, Encore is obligated to reimburse Denbury for up to $10 million of its expenses related to the Merger if specified termination events occur.

Sale of Barnett Shale Natural Gas Assets. In May 2009, we entered into an agreement to sell 60% of our Barnett Shale assets to Talon Oil and Gas LLC, a privately held company, for $270 million (before closing adjustments). The effective date under the agreement was June 1, 2009, and consequently operating net revenues after June 1, net of capital expenditures, along with any other purchase price adjustments, were adjustments to the selling price. On June 30, 2009, we completed approximately three-quarters of the sale, and closed the remaining portion of the sale on July 15, 2009. Net proceeds were $259.8 million (after closing adjustments, and net of $8.1 million for natural gas swaps transferred in the sale). We used the net proceeds from the sale to repay bank debt. We did not record a gain or loss on the sale in accordance with the full cost method of accounting.

Recent Management Changes. On June 30, 2009, under a management succession plan adopted by our Board of Directors and announced on February 5, 2009, Gareth Roberts, the Company s founder, relinquished his position as President and CEO and became Co-Chairman of the Board of Directors and assumed a non-officer role as the Company s Chief Strategist. Phil Rykhoek, previously Senior Vice President and Chief Financial Officer, became Chief Executive Officer; Tracy Evans, previously Senior Vice President Reservoir Engineering, became President and Chief Operating Officer; and Mark Allen, previously Vice President and Chief Accounting Officer, became Senior Vice President and Chief Financial Officer.

In connection with Mr. Roberts retirement as CEO and President of the Company, Mr. Roberts and the Company entered into a Founder s Retirement Agreement (the Agreement). Under this Agreement, Mr. Roberts received compensation of (i) $3.65 million in cash, plus (ii) the Company issued him $6.35 million of the Company s 9.75% Senior Subordinated Notes due 2016. As part of the Agreement, there are restrictions that prohibit Mr. Roberts from trading the Notes for two years, and he has entered into a non-compete arrangement with the Company through 2013. Mr. Roberts will continue to provide services to the Company as Co-Chairman of the Board of Directors and in a non-officer role as Chief Strategist.

Purchase of Hastings Field. On February 2, 2009, we closed the acquisition of Hastings Field located near Houston, Texas for approximately $201 million in cash. Hastings Field is a significant potential tertiary oil flood that we plan to flood with CO_2 delivered from Jackson Dome using our Green Pipeline, which is currently under construction. We originally entered into an agreement in November 2006 with a subsidiary of Venoco, Inc., that gave us the option to purchase their interest in the Hastings Field. As consideration for the purchase option, we made total payments of $50 million which makes our aggregate purchase price $251 million. The seller retained a 2% override and reversionary interest of approximately 25% following payout, as defined in the purchase agreement. We plan to commence flooding the field with CO_2 beginning in 2011, after completion of our Green Pipeline and construction of field recycling facilities. Under the purchase agreement, we are required to make net capital expenditures in this field totaling $179 million over the next six years, including our first obligation of $26.8 million during 2010, and are committed to begin CO_2 injections averaging 50 MMcf/d by the fourth quarter of 2012. Production from this field averaged 2,083 BOE/d during the third quarter of 2009, all of which was non-tertiary production.

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We have recorded the acquisition of Hastings Field in accordance with the Financial Accounting Standards Board (FASB) Accounting Standards Codification™ (FASC) Business Combinations topic, which became effective for acquisitions after December 31, 2008. Based on these new rules, we have allocated $105.6 million of the $246.8 million adjusted purchase price to proved properties, approximately $2.4 million to land, oilfield equipment and other related assets, and the remaining $138.8 million to goodwill. See further discussion on this acquisition in Note 2 to the Unaudited Condensed Consolidated Financial Statements.

Subordinated Debt Issuance. On February 13, 2009, we issued $420 million of 9.75% Senior Subordinated Notes due 2016 (the Notes). The Notes were sold to the public at 92.816% of par, plus accrued interest from February 13, 2009, which equates to an effective yield to maturity of approximately 11.25% (before offering expenses). Interest on the Notes will be paid on March 1 and September 1 of each year, beginning September 1, 2009. The Notes will mature on March 1, 2016. We used the net proceeds from the offering of approximately $381.4 million to repay most of the then outstanding debt on our bank credit facility. We issued an additional $6.35 million of Notes to Mr. Roberts on June 30, 2009 (see Recent Management Changes above).

Capital Resources and Liquidity

In a continuing effort to mitigate the effects of the deterioration in the capital markets and the steep decline in commodity prices in the last half of 2008, we have taken additional measures during the first nine months of 2009 to improve our liquidity. In February 2009, we issued $420 million of 9.75% Senior Subordination Notes and in June and July 2009, we completed the sale of 60% of our Barnett Shale assets. We used the $381.4 million proceeds from the February Notes issuance to repay the majority of our then-outstanding bank debt, and we did the same with the proceeds from our recent Barnett Shale sale, freeing up our credit line for future capital needs. We also entered into additional commodity derivative contracts for 2010 to protect our cash flow. Our derivative contracts as of September 30, 2009 are included in Note 6 to the Unaudited Condensed Consolidated Financial Statements.

Subsequent to September 30, 2009, we entered into additional costless collar crude oil commodity derivative contracts to protect our cash flows during 2010 as follows: 5,000 barrels per day during the first quarter of 2010 with a floor price of $70 per barrel and a ceiling price of $92.20 per barrel; 5,000 barrels per day during the second quarter of 2010 with a floor price of $70 per barrel and a ceiling price of $95.25 per barrel; and 5,000 barrels per day during the third and fourth quarters of 2010 with a floor price of $70 per barrel and a ceiling price of $96.50 per barrel. Also, in light of the recently announced acquisition of Encore and our desire to protect our cash flows given the increased debt levels we expect in connection with the acquisition, we recently entered into costless collar crude oil commodity derivative contracts for 25,000 barrels per day during 2011 with a floor price of $70 per barrel and a ceiling price of $102.58 per barrel.

We currently estimate our 2009 capital spending will be approximately $750 million, excluding capitalized interest and net of equipment leases, plus $201 million spent for our February 2009 Hastings Field acquisition. Our current 2009 capital budget includes approximately $500 million to be spent on our CO_2 pipelines, the majority of which will be spent on the Green Pipeline. The budget also assumes that we fund approximately $100 million of budgeted equipment purchases with operating leases, which is dependent upon securing acceptable financing. Through September 30, 2009, we have completed approximately $44 million of these leases. If we do not enter into a total of $100 million of operating leases during 2009, our net capital expenditures would increase accordingly, and we would anticipate funding those additional capital expenditures under our bank credit line.

Based on our current cash flow projections using futures prices as of the end of October 2009, and including the expected cash settlements on our 2009 oil derivative contracts, we anticipate that these projected 2009 capital expenditure amounts of approximately $750 million, plus our already closed $201 million Hastings acquisition, could, in the aggregate, exceed projected cash flow by as much as $450 million to $550 million. This shortfall should be covered by the $381.4 million of net proceeds from our February 2009 subordinated debt issuance and the estimated $259.8 million of net proceeds (after closing adjustments and net of $8.1 million for natural gas swaps transferred in the sale) from the sale of 60% of our Barnett Shale properties.

As part of our semi-annual bank review, on October 1, 2009 our bank borrowing base and commitment amounts were left unchanged at $900 million and $750 million, respectively. The borrowing base represents the amount that can be borrowed from a credit standpoint while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. We anticipate this credit line will be sufficient for our 2009 plans, and do not expect our bank credit line to be reduced by our banks unless commodity prices were to decrease significantly from current levels. Based on current projections, we expect to have little or no bank debt drawn at the end of 2009 assuming we achieve our $100 million budgeted equipment leasing program, leaving up to $750 million available on our bank line.

Although we have not yet set our capital budget for 2010, we do expect to utilize the net proceeds from our Barnett Shale sale to increase our capital spending above our projected 2010 cash flow levels. We have structured the financing for our proposed acquisition with Encore to provide us with an estimated level of liquidity similar to that expected before the acquisition. We currently do not anticipate raising any additional capital during 2009 unless needed for an acquisition or alternate financing associated with the recently announced merger discussed above in Overview Definitive Merger Agreement to Acquire Encore Acquisition Company. We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital

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spending up or down depending on cash flows; however, any such reduction in capital spending could reduce our anticipated production levels in future years. For 2009, we have contracted for certain capital expenditures, including construction of most of the Green Pipeline already in progress and two drilling rigs, and therefore the portion of capital that we could eliminate without significant penalty is limited (refer to Management s Discussion and Analysis of Financial Condition and Results of Operations Off-Balance Sheet Arrangements Commitments and Obligations in our 2008 Form 10-K for further information regarding these commitments).

Sources and Uses of Capital Resources

Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for each period. Our cash expenditures were \$54.8 million higher in the 2009 period and \$24.3 million lower in the 2008 period than the amounts listed below due to the increase (decrease) in our capital accruals in those periods.

	Nine Months Ended September 30,	
In thousands	2009	2008
Oil and natural gas exploration and development:		
Drilling	\$ 41,150	\$ 186,249
Geological, geophysical and acreage	10,713	14,084
Facilities	136,556	117,423
Recompletions	56,251	104,476
Capitalized interest	10,440	13,639
Total oil and natural gas exploration and development expenditures	255,110	435,871
Oil and gas property acquisitions	197,534	4,262
Total oil and natural gas capital expenditures	452,644	440,133
CO_2 capital expenditures		
CO_2 pipelines	456,590	139,890
CO_2 producing fields	28,562	90,658
Capitalized interest	38,259	5,885
Total CO_2 capital expenditures	523,411	236,433
Total	\$ 976,055	\$ 676,566

During the first nine months of 2009, we have recorded approximately \$833 million of cash used for capital expenditures, which includes \$49 million in capitalized interest and \$44 million that was subsequently leased in sale leaseback transactions. In addition, our liabilities for capital expenditures were approximately \$55 million lower at September 30, 2009 than at December 31, 2008, representing cash outflows related to our capital expenditures actually incurred in 2008. These amounts net together resulting in \$685 million of our \$750 million capital budget. In addition, we have approximately \$55 million of equipment available for sale leaseback financings for the remainder of 2009, which if completed, would leave \$120 million of our 2009 capital expenditure budget available for the fourth quarter. If we do not complete the full \$55 million of remaining equipment leases in 2009, it is likely that we would carry those over into 2010.

Our capital expenditures for the first nine months of 2009 were funded with \$406.4 million of cash flow from operations, \$259.8 million of net proceeds from the sale of a portion of our Barnett Shale natural gas assets and

$381.4 million of proceeds from the February 2009 issuance of 9.75% Senior Subordinated Notes. Our capital expenditures for the first nine months of 2008 were funded with $632.8 million of cash flow from operations, $225 million from the dropdown of CO_2 pipelines to Genesis, and $48.9 million from the proceeds from the second closing on our Louisiana property sale.

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Off-Balance Sheet Arrangements

Commitments and Obligations

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and various obligations for development and exploratory expenditures arising from purchase agreements, our capital expenditure program, or other transactions common to our industry. In addition, in order to recover our proved undeveloped reserves, we must also fund the associated future development costs as forecasted in the proved reserve reports. Our derivative contracts are discussed in Note 6 to the Unaudited Condensed Consolidated Financial Statements.

On February 2, 2009, we closed our $201 million purchase of Hastings Field. Under the agreement, we are required to make aggregate net cumulative capital expenditures in this field of approximately $179 million over the next six years cumulating as follows: $26.8 million by December 31, 2010, $71.5 million by December 31, 2011, $107.2 million by December 31, 2012, $142.9 million by December 31, 2013, and $178.7 million by December 31, 2014. If we fail to spend the required amounts by the due dates, we are required to make a cash payment equal to 10% of the cumulative shortfall at each applicable date. Further, we are committed to injecting at least an average of 50 MMcf/d of CO_2 (total of purchased and recycled) in the West Hastings Unit for the 90 day period prior to January 1, 2013. If such injections do not occur, we must either (1) relinquish our rights to initiate (or continue) tertiary operations and reassign to Venoco all assets previously purchased for the value of such assets at that time based upon the discounted value of the field s proved reserves using a 20% discount rate, or (2) make an additional payment of $20 million in January 2013, less any payments made for failure to meet the capital spending requirements as of December 31, 2012, and a $30 million payment for each subsequent year (less amounts paid for capital expenditure shortfalls) until the CO_2 injection rate in the Hastings Field equals or exceeds the minimum required injection rate.

We currently have long-term commitments to purchase CO_2 from eight proposed gasification plants, four of which are in the Gulf Coast region and four in the Midwest region (Illinois, Indiana and Kentucky). The Midwest plants are not only conditioned on the specific plants being constructed, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plants that would provide an acceptable economic return on the CO_2 pipeline that we would need to construct to transport these volumes to our existing CO_2 pipeline system. If all of these plants were to be built, these CO_2 sources are currently anticipated to provide us with aggregate CO_2 volumes of 1.2 Bcf/d to 1.9 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and providing CO_2 would be 2014, and there is some doubt as to whether they will be constructed at all. The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent all-in cost of CO_2 from our natural source (Jackson Dome) using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits. If all eight plants are built, the aggregate purchase obligation for this CO_2 would be around $280 million per year, assuming a $70 per barrel oil price, before any potential savings from our share of carbon emissions reduction credits. All of the contracts have price adjustments that fluctuate based on the price of oil. Construction has not yet commenced on any of these plants, and their construction is contingent on the satisfactory resolution of various issues, including financing. While it is likely that not every plant currently under contract will be constructed, there are several other plants under consideration that could provide CO_2 to us that would either supplement or replace some of the CO_2 volumes from the eight proposed plants for which we currently have CO_2 output purchase contracts. We are having ongoing discussions with several of these other potential sources.

Neither the amounts nor the terms of any other commitments or contingent obligations have changed significantly from the year-end amounts reflected in our 2008 Form 10-K filed in March 2009 other than as discussed above, and other than our commitments associated with our recently announced acquisition of Encore, discussed above in Overview Definitive Merger Agreement to Acquire Encore Acquisition Company , including the fee letters executed in connection with the bank commitment letter that provide for Denbury to pay up to approximately $50 million in fees if the loans do not close, and our February 2009 subordinated debt issuance discussed in Overview Subordinated Debt Issuance . Please refer to Management s Discussion and Analysis of Financial Condition and Results of

Operations Off-Balance Sheet Arrangements Commitments and Obligations contained in our 2008 Form 10-K for further information regarding our commitments and obligations.

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CO_2 Operations

Our focus on CO_2 operations is becoming an ever-increasing part of our business and operations. We believe that there are significant additional oil reserves and production that can be obtained through the use of CO_2, and we have outlined certain of this potential in our 2008 annual report and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations and the section entitled CO_2 Operations contained in our 2008 Form 10-K for further information regarding these matters.

During 2009, we drilled one additional CO_2 source well to further increase our production capacity and reserves at Jackson Dome. Preliminary estimates of CO_2 reserves added during the third quarter are 358 Bcf of CO_2 as a result of drilling and completing the Kuriger Trust well at Gluckstadt Field. We estimate that we are currently capable of producing between 900 MMcf/d and 1 Bcf/d of CO_2. During the third quarter of 2009, our CO_2 production averaged 629 MMcf/d, as compared to an average of approximately 630 MMcf/d during the third quarter of 2008. We used 86% of this production, or 539 MMcf/d, in our tertiary operations during the third quarter of 2009, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments. During the third quarter of 2009, we shutdown for maintenance two tertiary fields (Tinsley and Mallalieu Fields) which resulted in our CO_2 production being slightly curtailed during the quarter. Also, because we had a delay in the commissioning of the Delhi pipeline, with the resultant delay in initiating CO_2 injections at the Delhi Field, we did not require an increase in our CO_2 production during the third quarter of 2009. However, we plan to initiate CO_2 injections at Delhi Field during November 2009, which will increase our tertiary oil field CO_2 requirements, so we expect a corresponding increase in our CO_2 production volumes going forward.

We spent approximately $0.16 per Mcf to produce our CO_2 during the first nine months of 2009, comprised of $0.14 per Mcf during the first quarter of 2009, $0.18 per Mcf during the second quarter of 2009, and $0.19 per Mcf during the third quarter of 2009. This rate is down significantly from $0.25 per Mcf during the first nine months of 2008, due primarily to decreased CO_2 royalty expense as a result of lower oil prices (upon which royalties are based) in the first nine months of 2009. Our estimated total cost per thousand cubic feet of CO_2 during the first nine months of 2009 was approximately $0.25, after inclusion of depreciation and amortization expense, down from the 2008 first nine months average of $0.33 per Mcf. Our estimated total cost per thousand cubic feet of CO_2 during the third quarter of 2009 was approximately $0.27, after inclusion of depreciation and amortization expense.

We recently announced that we have initiated a comprehensive feasibility study of a possible long-term CO_2 pipeline project which would connect proposed gasification plants in the Midwest to the Company s existing CO_2 pipeline infrastructure in Mississippi or Louisiana. Two of the proposed plants are in the term sheet negotiation phase of a U.S. Department of Energy Loan Guarantee Program (see Off-Balance Sheet Obligations Commitments and Obligations) which still require successful finalization of negotiations with the Department of Energy (DOE) to receive such guarantees. The Illinois Department of Commerce and Economic Opportunity has provided financial assistance for the feasibility study for the Illinois portion of the pipeline. The feasibility study is expected to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Our current preliminary estimates suggest this would be a 500 to 700 mile pipeline system with a preliminary cost estimate of approximately $1.0 billion, based on the cost of other pipelines recently built or under construction by the Company. It is estimated that the study will be completed in the fourth quarter of 2009, following which, we will evaluate external market conditions, potential financing opportunities and construction of the proposed gasification projects, and make a decision as to whether or not we will take initial steps to build such a pipeline.

A third proposed gasification plant for which Denbury has a CO_2 output purchase contract, was also selected by the loan guarantee program. The Company plans to commence a pipeline study for this plant proposed to be built along the Gulf Coast of Mississippi, which would likely be a 110 mile pipeline that connects to the existing Free State Pipeline.

In addition to our natural source of CO_2 and the proposed gasification plants discussed above (see Off-Balance Sheet Arrangements Commitments and Obligations), we continue to have ongoing discussions with owners of existing plants of various types that emit CO_2 which we may be able to purchase. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which includes at a minimum, compression and dehydration facilities. Most of these existing plants emit relatively small volumes of CO_2, generally less than the proposed gasification plants, but such volumes may still be attractive if the source is located near our Green Pipeline. The capture of CO_2 could also be influenced by potential federal legislation, which could impose economic penalties for the emission of CO_2. We believe that we are a likely purchaser of CO_2 produced in our area of operations because of the scale of our tertiary operations, our CO_2 pipeline infrastructure, and our large natural source of CO_2 (Jackson Dome), which can act as a swing CO_2 source to balance CO_2 supply and demand.

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The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2008 and the first, second and third quarters of 2009.

	Average Daily Production (BOE/d)						
Tertiary Oil Field	First Quarter 2008	Second Quarter 2008	Third Quarter 2008	Fourth Quarter 2008	First Quarter 2009	Second Quarter 2009	Third Quarter 2009
Phase I:							
Brookhaven	2,638	2,714	2,772	3,178	3,451	3,466	3,397
Little Creek area	1,807	1,661	1,556	1,706	1,619	1,560	1,356
Mallalieu area	6,099	6,260	5,339	5,056	4,490	4,264	3,679
McComb area	1,632	1,818	2,061	2,092	2,246	2,429	2,473
Lockhart Crossing			182	555	607	698	882
Phase II:							
Eucutta	2,699	2,933	3,262	3,538	3,813	4,145	4,068
Heidelberg						250	829
Martinville	793	715	736	1,213	1,118	951	720
Soso	1,488	1,885	2,358	2,704	2,705	2,589	2,813
Phase III:							
Tinsley		675	1,518	1,832	2,390	3,402	3,558
Phase IV:							
Cranfield					144	338	572
Total tertiary oil production	17,156	18,661	19,784	21,874	22,583	24,092	24,347
Tertiary operating expense per Bbl	$ 20.81	$ 24.67	$ 26.81	$ 21.86	$ 20.48	$ 20.86	$ 23.14

Oil production from our tertiary operations increased to an average of 24,347 Bbls/d in the third quarter of 2009, a 23% increase over our third quarter 2008 tertiary production level of 19,784 Bbls/d and a 1% increase over our second quarter 2009 tertiary production level. These increases are the result of the production growth in our more recent floods such as Tinsley, Lockhart Crossing, Cranfield and Heidelberg Fields, where production has increased every quarter as the CO_2 floods have been expanded and production response occurs across the fields. We had our first production response from Cranfield Field during the first quarter of 2009 and our first response from Heidelberg Field in the second quarter of 2009, a little earlier than anticipated. The Tinsley field has been one of our top performing tertiary oil fields. During 2009, CO_2 injection was initiated in the lower half of Tinsley Phase 2 and all of Tinsley Phase 3. After reaching optimum bottom hole pressure (BHP) late in the third quarter of 2009, and after a planned shutdown to increase facility fluid handling capacity, approximately twenty-one shut-in wells will be turned to production. The tertiary oil production in Tinsley is expected to increase as the oil cut increases over time in these twenty-one wells. The declines at Mallalieu Field are partially due to CO_2 recycle volumes exceeding the plant capacity, which limited production volumes. We have expanded the capacity of the facility, with it becoming operational early in the fourth quarter of 2009. Now that the recycle capacity has been expanded, we expect production at Mallalieu Field to plateau. Additionally, the second quarter decline at Soso Field was largely due to water handling limitations that have recently been addressed and we saw production increases at Soso Field during the third quarter of 2009. The Delhi pipeline is essentially complete, and we anticipate initiating CO_2 injections at Delhi Field (Phase V) during November 2009. We currently anticipate tertiary production response at Delhi Field around mid-year 2010.

During the third quarter of 2009, our operating costs for our tertiary properties averaged $23.14 per Bbl, lower than the prior year s third quarter average of $26.81 per Bbl, but higher than our second quarter 2009 average of $20.86 per Bbl. For the first nine months of 2009, the operating costs on our tertiary properties averaged $21.53 per Bbl as compared to $24.25 per Bbl in the prior year period. Our costs have increased on a gross basis due to our new tertiary floods and ongoing expansion of existing floods, but they have decreased on a per Bbl basis from the third quarter and first nine months of 2008, primarily due to our increased production and to the reduced cost of CO_2 in the current year periods. On a per Bbl basis, our cost of CO_2 decreased by $2.70 per BOE, from $6.95 per Bbl in the third quarter of 2008 to $4.25 per Bbl in the third quarter of 2009, primarily due to the reduction in oil prices to which our CO_2 costs are partially tied. In addition, our workover costs were $1.89 lower on a per BOE basis in the third quarter of 2009 than in the

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prior year period. The increase in operating costs from the second quarter of 2009 on a per BOE basis is primarily due to our new floods in Cranfield and Heidelberg, and to an increase in workover expenses between the sequential periods of $0.80 per barrel. In addition, the cost of our CO_2 increased in the current quarter as a result of higher oil prices, as discussed above. For any specific field, we expect our tertiary lease operating expense per BOE to be high initially, then decrease as production increases, ultimately leveling off until production begins to decline toward the latter life of the field, when lease operating expense per BOE will again increase.

Operating Results

As summarized in the Overview section above and discussed in more detail below, our operating results for the third quarter and first nine months of 2009 were significantly lower as compared to the same periods in the prior year. The primary factors impacting our operating results were lower oil and natural gas commodity prices in the current year periods, decreased production, due mainly to the sale of 60% of our Barnett Shale natural gas assets, non-cash losses associated with fair value changes in our oil and natural gas derivative contracts and generally higher costs, which are explained in more detail below.

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2009 and 2008 are included in the following table.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share and unit data	2009	2008	2009	2008
Operating results				
Net income (loss)	$ 26,885	$ 157,548	$ (78,652)	$ 344,603
Net income (loss) per common share basic	0.11	0.64	(0.32)	1.41
Net income (loss) per common share diluted	0.11	0.63	(0.32)	1.36
Cash flow from operations	145,645	262,442	406,434	632,771
Average daily production volumes				
Bbls/d	34,926	31,078	36,819	30,859
Mcf/d	46,399	89,009	75,523	89,087
BOE/d[1]	42,659	45,913	49,406	45,707
Operating revenues				
Oil sales	$ 208,128	$ 321,965	$ 529,563	$ 899,368
Natural gas sales	13,193	80,143	71,379	229,180
Total oil and natural gas sales	$ 221,321	$ 402,108	$ 600,942	$ 1,128,548
Oil and natural gas derivative contracts[2]				
Cash receipt (payment) on settlement of derivative contracts	$ 18,527	$ (24,072)	$ 146,365	$ (60,714)
Non-cash fair value adjustment income (expense)	(22,284)	86,079	(323,426)	17,123
Total income (expense) from oil and natural gas derivative contracts	$ (3,757)	$ 62,007	$ (177,061)	$ (43,591)
Operating expenses				
Lease operating expenses	$ 83,300	$ 85,308	$ 241,908	$ 228,134
Production taxes and marketing expenses [3]	10,461	19,335	30,437	56,601
Total production expenses	$ 93,761	$ 104,643	$ 272,345	$ 284,735
Non-tertiary CO_2 operating margin				
CO_2 sales and transportation fees [4]	$ 3,659	$ 3,471	$ 9,708	$ 9,705
CO_2 operating expenses	(1,047)	(1,240)	(3,442)	(2,836)
Non-tertiary CO_2 operating margin	$ 2,612	$ 2,231	$ 6,266	$ 6,869
Unit prices including impact of derivative settlements[2]				

Oil price per Bbl	$ 70.54	$ 108.70	$ 67.25	$ 102.74
Gas price per Mcf	3.09	8.21	3.46	8.16
Unit prices excluding impact of derivative settlements[2]				
Oil price per Bbl	$ 64.77	$ 112.61	$ 52.68	$ 106.37
Gas price per Mcf	3.09	9.79	3.46	9.39
Oil and natural gas operating revenues and expenses per BOE[1]				
Oil and natural gas revenues	$ 56.39	$ 95.20	$ 44.55	$ 90.11
Oil and natural gas lease operating expenses	$ 21.22	$ 20.20	$ 17.94	$ 18.22
Oil and natural gas production taxes and marketing expense	2.67	4.58	2.26	4.52
Total oil and natural gas production expenses	$ 23.89	$ 24.78	$ 20.20	$ 22.74

(1) Barrel of oil equivalent using the ratio of one barrel of oil to six Mcf of natural gas (BOE).

(2) See also Market Risk Management below for information concerning the Company s derivative transactions.

(3) Includes Transportation expense Genesis.

(4) Includes deferred revenue of $1.2 million for each of the three month periods ended September 30,

2009 and 2008 and $3.2 million and $3.4 million for the nine month periods ended September 30, 2009 and 2008, respectively, associated with volumetric production payments with Genesis. Also includes transportation income from Genesis of $1.5 million for each of the three month periods ended September 30, 2009 and 2008 and $4.0 million and $4.1 million for the nine month periods ended September 30, 2009 and 2008.

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Production: Production by area for each of the quarters of 2008 and the first, second and third quarters of 2009 is listed in the following table.

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2008	Second Quarter 2008	Third Quarter 2008	Fourth Quarter 2008	First Quarter 2009	Second Quarter 2009	Third Quarter 2009
Tertiary oil fields	17,156	18,661	19,784	21,874	22,583	24,092	24,347
Mississippi non-CO_2 floods	12,128	11,617	11,694	12,150	11,904	10,043	8,931
Texas	13,522	14,068	12,701	12,576	17,063	16,088	7,579
Onshore Louisiana	905	663	512	418	708	885	699
Alabama and other	1,189	1,296	1,222	1,219	1,150	1,161	1,103
Total Company	44,900	46,305	45,913	48,237	53,408	52,269	42,659

As outlined in the above table, production in the third quarter of 2009 averaged 42,659 BOE/d, a 10% increase from third quarter 2008 production levels after adjusting for the sale of 60% of our Barnett Shale natural gas assets. The increase over the prior year third quarter was primarily due to a 23% increase in tertiary oil production, and production from Hastings Field which the Company acquired in February 2009, offset in part by the expected decrease in the Company s non-tertiary Mississippi production. The increase in our tertiary operations is discussed above under Results of Operations CO_2 Operations.

Our Texas Barnett Shale production averaged 4,948 BOE/d during the third quarter of 2009. As discussed previously, we have recently sold 60% of our interests in the Barnett Shale so our fourth quarter 2009 production will be reduced correspondingly. The acquisition of Hastings Field in February 2009 added 2,083 BOE/d during the third quarter of 2009 and 1,946 BOE/d during the first nine months of 2009 to our Texas area production.

Production in the Mississippi non-CO_2 floods area has decreased from third quarter and first nine month 2008 levels, as well as from second quarter 2009 levels. Most of this decrease is due to the expected gradual decline in Heidelberg Field due to depletion, and less drilling activity developing natural gas in the Selma Chalk. Our drilling activity in Sharon Field (natural gas) in the latter part of 2008 helped offset the declines in the first quarter of 2009, but production there declined in the nine months of 2009 as we have not drilled any additional wells in this field this year.

Oil and Natural Gas Revenues: Due to the significant decrease in oil and natural gas prices between the first nine months of 2008 and 2009, and due to the decrease in production in the third quarter of 2009 resulting mainly from the sale of 60% of our Barnett Shale natural gas assets, our oil and natural gas revenues dropped sharply in the third quarter and first nine months of 2009 as compared to those revenues in the same periods of 2008. These changes in revenues, excluding any impact of our derivative contracts, are seen in the following table.

	Three Months Ended September 30, 2009 vs. 2008		Nine Months Ended September 30, 2009 vs. 2008	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues

Change in revenues due to:				
Increase (decrease) in production	$ (28,492)	(7%)	$ 86,895	8%
Decrease in commodity prices	(152,295)	(38%)	(614,501)	(54%)
Total decrease in revenues	$ (180,787)	(45%)	$ (527,606)	(46%)

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Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second and third quarters and first nine month periods of 2008 and 2009:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008	2009	2008	2009	2008
Net Realized Prices:								
Oil price per Bbl	$39.34	$91.24	$54.53	$114.67	$64.77	$112.61	$52.68	$106.37
Gas price per Mcf	4.09	7.80	2.98	10.55	3.09	9.79	3.46	9.39
Price per BOE	34.97	76.65	44.48	98.07	56.39	95.20	44.55	90.11
NYMEX Differentials:								
Oil per Bbl	$ (3.99)	$ (6.50)	$ (5.30)	$ (9.64)	$ (3.47)	$ (6.06)	$ (4.54)	$ (7.23)
Natural Gas per Mcf	(0.41)	(0.92)	(0.82)	(0.92)	(0.33)	0.77	(0.44)	(0.35)

Our Company-wide oil price NYMEX differential improved in the third quarter and first nine months of 2009 over our differential in the comparable prior year periods, due primarily to the decrease in oil prices. Our oil price NYMEX differential improved in the third quarter of 2009, as compared to the previous quarter, primarily due to the reduced natural gas liquid production associated with the sold Barnett Shale properties which have a significantly higher differential to NYMEX.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be quite large, these differentials are very seldom more than a dollar above or below NYMEX prices.

Oil and Natural Gas Derivative Contracts: The following table summarizes the impact that our oil and natural gas derivative contracts had on our operating results for the three and nine month periods ended September 30, 2009 and 2008.

	Non-Cash Fair Value Gain/(Loss)		Cash Settlements Receipt/(Payment)	
In thousands	2009	2008	2009	2008
Crude oil derivative contracts:				
First quarter	$ (95,861)	$ 2,638	$ 85,836	$ (7,392)
Second quarter	(189,318)	(7,557)	42,002	(12,131)
Third quarter	(20,850)	22,652	18,527	(11,186)
September year-to-date	$ (306,029)	$ 17,733	$ 146,365	$ (30,709)
Natural gas derivative contracts:				
First quarter	$ (10,490)	$ (41,371)	$	$ (656)
Second quarter	(5,473)	(22,666)		(16,463)
Third quarter	(1,434)	63,427		(12,886)
September year-to-date	$ (17,397)	$ (610)	$	$ (30,005)

Total derivative contracts:				
First quarter	$ (106,351)	$ (38,733)	$ 85,836	$ (8,048)
Second quarter	(194,791)	(30,223)	42,002	(28,594)
Third quarter	(22,284)	86,079	18,527	(24,072)
September year-to-date	$ (323,426)	$ 17,123	$ 146,365	$ (60,714)

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Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our oil and natural gas derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts are recognized currently in the income statement. During the third quarter of 2009, we recognized total non-cash fair value expense of $22.3 million and for the first nine months of 2009, we recognized total non-cash fair value expense of $323.4 million. Of these amounts, $21.4 million in the third quarter and $231.8 million in the first nine months of 2009 related to our 2009 oil collars, partially reversing the $242.2 million gain we recognized on these collars during the fourth quarter of 2008. The remaining non-cash fair value expense recognized during the third quarter and first nine months of 2009 was made up of charges on the oil derivative contracts we entered into during 2009 and on our natural gas swaps entered into during the first half of 2009, which cover a portion of our 2010 and 2011 calendar year production (see Note 6 to the Unaudited Condensed Consolidated Financial Statements for a summary of our oil and natural gas derivative contracts). During the third quarter and first nine months of 2008, we recognized non-cash fair value income of $86.1 million and $17.1 million, respectively, on our oil and natural gas derivative contracts.

During the third quarter and first nine months of 2009, we received cash settlements of $18.5 million and $146.4 million on our derivative contracts. During the third quarter and first nine months of 2008, we made cash payments of $24.1 million and $60.7 million on our derivative contracts, giving us a total change in earnings impact from both non-cash fair value adjustments and cash settlements between the two nine-month periods of $133.5 million.

Production Expenses: Our lease operating expenses increased between the comparable first nine months of 2009 versus 2008 on a gross basis as a result of (i) our increasing emphasis on tertiary operations and additional tertiary fields moving into the productive phase (see discussion of those expenses under CO_2 Operations above), (ii) the acquisition of Hastings Field in February 2009, (iii) increased personnel and related costs, (iv) higher electrical costs to operate our properties and (v) increasing lease payments for certain equipment in our tertiary operating facilities, offset in part by lower CO_2 costs due primarily to lower oil prices in the 2009 periods. Our lease operating expenses decreased on a per BOE basis between the comparable first nine months of 2009 versus 2008 due to the lower oil and natural gas prices, which has helped to lower the cost for certain goods and services and has reduced our cost for CO_2 (see Results of Operations CO_2 Operations for a more detailed discussion). We expect our tertiary operating costs to partially correlate with oil prices, as the price we pay for CO_2 is partially tied to oil prices. Our operating costs have increased during the last few years as oil prices have increased and the demand for goods and services has steadily risen, but with the recent drop in oil prices, we expect that lower demand for certain goods and services will gradually cause prices for those items to decrease or stabilize over time. During the third quarter of 2009, Company-wide lease operating costs averaged $21.22 per BOE, up from $20.20 per BOE during the third quarter of 2008, primarily due to the fact that our incremental growth in production quarter-over-quarter (excluding the sale of a portion of our interest in the Barnett Shale properties) was primarily from higher cost producing properties such as our tertiary operations and Hastings Field production. On a pro forma basis, after adjusting our operating results to remove 60% of our Barnett Shale production and lease operating expense, Company-wide lease operating expense for the first nine months of 2009 would have been approximately $19.71 per BOE, as compared to actual nine months 2009 operating costs per BOE of $17.94.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes, and therefore were lower in the 2009 periods compared to the 2008 periods, because the severe decrease in commodity prices more than offset our increase in production. Transportation and plant processing fees were approximately $1.8 million lower in the third quarter and respective first nine months of 2009 as compared to the same periods in 2008.

General and Administrative Expenses

General and administrative (G&A) expenses increased 60% between the respective third quarters and 74% between the respective first nine months of 2009 and 2008 as set forth below:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE data and employees	2009	2008	2009	2008
Gross cash G&A expense	$ 36,091	$ 31,302	$ 107,565	$ 90,879
Employee stock-based compensation	6,101	4,131	18,600	12,590
Founder s compensation award			10,000	
Incentive compensation for Genesis management	3,573		9,111	
State franchise taxes	1,102	863	3,341	2,548
Operator labor and overhead recovery charges	(19,333)	(18,027)	(58,110)	(50,788)
Capitalized exploration and development costs	(3,496)	(3,264)	(10,679)	(9,408)
Net G&A expense	$ 24,038	$ 15,005	$ 79,828	$ 45,821
G&A per BOE:				
Net cash G&A expense	$ 3.63	$ 2.57	$ 3.09	$ 2.66
Net stock-based compensation	1.30	0.78	1.16	0.80
Founder s compensation award			0.74	
Incentive compensation for Genesis management	0.91		0.68	
State franchise tax	0.28	0.20	0.25	0.20
Net G&A expense	$ 6.12	$ 3.55	$ 5.92	$ 3.66
Employees as of September 30	806	768	806	768

Gross cash G&A expenses increased $4.8 million, or 15%, between the respective third quarters and $16.7 million, or 18%, between the respective first nine months. The majority of the increases in gross G&A expenses between the respective quarters and first nine month periods related to increases in compensation and personnel-related costs, due primarily to the increase in employees and salary increases, which we consider necessary in order to remain competitive in our industry. Stock compensation expense increased to $6.1 million during the third quarter of 2009 from $4.1 million for the third quarter of 2008, due primarily to the increase in employees and changes in the mix of compensation awarded to employees. On a nine month basis, stock compensation was approximately $18.6 million for 2009 and $12.6 million for 2008. As discussed above in Overview Recent Management Changes, we also expensed $10.0 million in the second quarter of 2009 related to a Founder s Retirement Agreement for Gareth Roberts as he retired as CEO and President of the Company on June 30, 2009.

Also adding to the increase in net G&A expense for the 2009 periods was a charge relating to incentive compensation awards for the management of Genesis of $3.6 million in the third quarter of 2009 and $9.1 million in the first nine months of 2009. As incentive compensation for Genesis management, our subsidiary which is the general partner of Genesis Energy, LP, awarded management the right to earn an interest in the incentive distributions we receive. These awards are subject to vesting over four years and achieving future levels of cash available before reserves on a per unit basis, among other conditions. The annual expense is currently expected to be less in future years, although it will fluctuate based on future performance and other market conditions. See Note 5, Related Party Transactions Genesis to the Unaudited Condensed Consolidated Financial Statements for further information regarding these incentive compensation awards.

The increase in gross G&A was offset in part by an increase in operator overhead recovery charges in the third quarter and first nine months of 2009. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year and increased compensation expense, the amount we recovered as operator overhead charges increased by 7% between the third quarters of 2008 and 2009 and increased by 14% between the first nine months of 2008 and 2009. Capitalized exploration and development costs also increased by 7% between the third quarters of 2008 and 2009 and increased by 14% between the first nine months of 2008 and 2009, primarily as a result of increases in personnel and compensation costs.

The net effect was a 60% increase in net G&A expense between the respective third quarters and an 74% increase between the first nine months of 2009 and 2008. On a per BOE basis, G&A costs also increased, although at a higher percentage rate as a result of lower production resulting from the Barnett Shale sale, increasing 72% in the third quarter of 2009 as compared to levels in the third quarter of 2008, and 62% when comparing the first nine months of 2009 to the prior year period.

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Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE data and interest rates	2009	2008	2009	2008
Cash interest expense	$ 28,694	$ 17,209	$ 80,296	$ 42,287
Non-cash interest expense	2,037	410	5,363	1,225
Less: Capitalized interest	(20,872)	(6,713)	(48,699)	(19,524)
Interest expense	$ 9,859	$ 10,906	$ 36,960	$ 23,988
Interest income and other	$ 434	$ 1,895	$ 1,948	$ 3,525
Net cash interest expense and other income per BOE (1)	$ 1.89	$ 2.10	$ 2.21	$ 1.59
Average debt outstanding	$ 1,240,827	$ 780,129	$ 1,246,266	$ 713,714
Average interest rate (2)	9.2%	8.8%	8.6%	7.9%

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.

(2) Includes commitment fees but excludes debt issue costs and amortization of discount and premium.

Interest expense decreased $1.0 million, or 10%, comparing the third quarters of 2008 and 2009, but increased $13.0 million, or 54%, comparing levels in the first nine months of 2008 and 2009. The decrease in interest expense between the respective third quarters is primarily a result of increased interest capitalization relating mainly to our CO_2 pipelines currently under construction, offset in part by higher average debt levels resulting from the Hastings Field acquisition in early February 2009 and incremental borrowings to fund our development program. For the first nine month periods, the increase in our interest expense attributable to higher debt and higher average interest rates during the period, was offset in part by an increase in capitalized interest in the 2009 periods, as mentioned above. Our average interest rate is higher in the current year periods than in the prior year periods as a result of the two pipeline dropdown transactions with Genesis mid-2008, which were recorded as financing leases and carry a higher imputed rate of interest, and the February 2009 issuance of $420 million of 9.75% Senior Subordinated Notes.

Depletion, Depreciation and Amortization

	Three Months Ended September 30,	Nine Months Ended September 30,

In thousands, except per BOE data	2009	2008	2009	2008
Depletion and depreciation of oil and natural gas properties	$ 44,935	$ 48,638	$ 151,890	$ 140,648
Depletion and depreciation of CO_2 assets	4,399	4,047	12,960	10,673
Asset retirement obligations	823	762	2,460	2,286
Depreciation of other fixed assets	3,368	2,877	9,835	7,289
Total DD&A	$ 53,525	$ 56,324	$ 177,145	$ 160,896
DD&A per BOE:				
Oil and natural gas properties	$ 11.66	$ 11.69	$ 11.44	$ 11.41
CO_2 assets and other fixed assets	1.98	1.64	1.69	1.44
Total DD&A cost per BOE	$ 13.64	$ 13.33	$ 13.13	$ 12.85

Depletion and depreciation of oil and natural gas properties decreased during the third quarter of 2009 compared to the same period in 2008 due primarily to decreased production resulting from the sale of a portion of our Barnett Shale natural gas assets. Depletion and depreciation of oil and natural gas properties increased during the first nine months of 2009 as compared to 2008 primarily due to an increased depletion base resulting from capital expenditures and the transfer of unevaluated costs into the full cost pool late in 2008.

Our depletion, depreciation and amortization (DD&A) rate for oil and natural gas properties on a per BOE basis remained relatively constant between the respective periods. In the second quarter of 2009, we booked approximately 10.9 million barrels of incremental oil reserves related to our tertiary operations at Cranfield Field, as a result of the oil production response to the CO_2

DENBURY RESOURCES INC.
Management s Discussion and Analysis of Financial Condition and Results of Operations

injections in that field. Correspondingly, we moved approximately $82.4 million from unevaluated properties to the full cost pool relating to Cranfield, representing the acquisition costs and development expenditures incurred on the field prior to recognizing proved reserves.

We continually evaluate the performance of our other tertiary projects, and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that quarter. Since we adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future. We currently do not anticipate that any significant incremental reserves will be recognized in the balance of 2009 as we do not expect any production from any other new floods before year-end.

Our DD&A rate for our CO_2 and other fixed assets increased in the third quarter of 2009 as compared to the rate in the comparable quarter of 2008 primarily as a result of the Heidelberg CO_2 pipeline being placed into service during 2008, and due to lower production levels in the third quarter of 2009. At September 30, 2009, we had $870.4 million of costs related to CO_2 pipelines under construction. These costs were not being depreciated at September 30, 2009. Depreciation of these pipelines will commence as each segment of pipeline is placed into service.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at March 31, 2009, June 30, 2009 or September 30, 2009. However, if oil prices were to decrease significantly in subsequent periods, we may be required to record additional write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, and additional capital spent. The SEC adopted major revisions to its rules governing oil and gas company reporting requirements which are effective for us beginning with our December 31, 2009 Form 10-K. Under these new rules, the full cost ceiling value will be calculated using an average price based on the first day of every month during the period.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE amounts and tax rates	2009	2008	2009	2008
Current income tax expense (benefit)	$ (6,160)	$ 12,689	$ 18,140	$ 44,769
Deferred income tax expense (benefit)	20,537	83,480	(67,869)	163,909
Total income tax expense (benefit)	$ 14,377	$ 96,169	$ (49,729)	$ 208,678
Average income tax expense (benefit) per BOE	$ 3.66	$ 22.77	$ (3.69)	$ 16.66
Effective tax rate	34.9%	37.9%	38.7%	37.7%

Our income tax provision was based on an estimated statutory rate of approximately 38%. Our effective tax rate has generally been slightly lower than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction, offset in part by compensation arising from certain equity compensation that cannot be deducted for tax purposes in the same manner as book expense. In the third quarters and first nine months of both years, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits. Included in the first nine months of 2009 is approximately $23 million in current taxes associated with the completion of the sale of a portion of our Barnett Shale assets. We recognized a current income tax benefit in the third quarter of 2009 and a slightly lower tax rate as a result of return to provision revisions and the estimated taxes related to the Barnett Shale property sale completed in the second and third quarters of 2009. As of December 31, 2008, after we had booked our return to provision adjustments, we had an estimated $47 million of enhanced oil recovery credits to carry forward that can be utilized to reduce our current income taxes during 2009 or future years.

In the second quarter of 2008 we obtained approval from the IRS to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Although the overall effects of this accounting change are still under audit, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007, along with other deferred tax benefits, and in the second quarter of 2008 we reduced our current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it could defer the amount of cash taxes the Company might otherwise pay over the next several years.

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Per BOE Data

The following table summarizes our cash flow, DD&A and results of operations on a per BOE basis for the comparative periods. Each of the individual components is discussed above.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Per BOE data	2009	2008	2009	2008
Oil and natural gas revenues	$ 56.39	$ 95.20	$ 44.55	$ 90.11
Gain (loss) on settlements of derivative contracts	4.72	(5.70)	10.85	(4.84)
Lease operating expenses	(21.22)	(20.20)	(17.94)	(18.22)
Production taxes and marketing expenses	(2.67)	(4.58)	(2.26)	(4.52)
Production netback	37.22	64.72	35.20	62.53
Non-tertiary CO_2 operating margin	0.67	0.53	0.46	0.55
General and administrative expenses	(6.12)	(3.55)	(5.92)	(3.66)
Net cash interest expense and other income	(1.89)	(2.10)	(2.21)	(1.59)
Abandoned acquisition costs		(7.20)		(2.43)
Current income taxes and other	5.03	(2.41)	1.26	(2.93)
Changes in assets and liabilities relating to operations	2.20	12.14	1.34	(1.94)
Cash flow from operations	37.11	62.13	30.13	50.53
DD&A	(13.64)	(13.33)	(13.13)	(12.85)
Deferred income taxes	(5.23)	(19.76)	5.03	(13.09)
Non-cash commodity derivative adjustments	(5.68)	20.38	(23.98)	1.37
Changes in assets and liabilities and other non-cash items	(5.71)	(12.12)	(3.88)	1.56
Net income (loss)	$ 6.85	$ 37.30	$ (5.83)	$ 27.52

Market Risk Management

Debt

We finance some of our acquisitions and other expenditures with fixed and variable rate debt. These debt agreements expose us to market risk related to changes in interest rates. We had $20 million of bank debt outstanding as of September 30, 2009. The carrying value of our bank debt is approximately fair value based on the fact that it is subject to short-term floating interest rates that approximate the rates available to us for those periods. We adjusted the estimated fair value measurements of our bank debt at September 30, 2009, for estimated nonperformance risk. This estimated nonperformance risk totaled approximately $1.5 million and was determined utilizing industry credit default swaps. None of our existing debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease with Genesis (see Note 5, Related Party Transactions Genesis to our Unaudited Condensed Consolidated Balance Sheets) in the event of significant downgrades of our corporate credit rating by the rating agencies, Genesis can require certain credit enhancements from us, and possibly other remedies under the lease. The fair value of the subordinated debt is based on quoted market prices. The following table presents the carrying and fair values of our debt, along with average interest rates at September 30, 2009.

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In thousands	2011	Expected Maturity Dates 2013	2015	2016	Carrying Value	Fair Value
Variable rate debt:						
Bank debt (weighted average interest rate of 0.02% at September 30, 2009)	$20,000	$	$	$	$ 20,000	$ 18,500
Fixed rate debt:						
7.5% subordinated debt due 2013 (fixed rate of 7.5%)		225,000			224,320	225,000
7.5% subordinated debt due 2015 (fixed rate of 7.5%)			300,000		300,535	298,000
9.75% subordinated debt due 2016 (fixed rate of 9.75%)				426,350	398,855	453,000

Oil and Natural Gas Derivative Contracts

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. Recently, we have employed a strategy to hedge a portion of our production looking out 12 to 15 months from each quarter, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current world-wide economic uncertainties. See Note 6 to the Unaudited Condensed Consolidated Financial Statements for details regarding our derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. All of our derivative contracts are with parties that are lenders under our Senior Bank Loan. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts. We have measured nonperformance risk based upon credit default swaps or credit spreads. At September 30, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $2.8 million and $3.7 million, respectively, for estimated nonperformance risk.

For accounting purposes, we do not apply hedge accounting to our oil and natural gas derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. Information regarding our current derivative contract positions and results of our historical derivative activity is included in Note 6 to the Unaudited Condensed Consolidated Financial Statements.

At September 30, 2009, our derivative contracts were recorded at their fair value, which was a net liability of approximately $69.2 million, a significant change from the $249.7 million fair value asset recorded at December 31, 2008. This change is primarily related to the expiration of oil derivative contracts during the first nine months of 2009, and to the oil and natural gas futures prices as of September 30, 2009 in relation to the new commodity derivative contracts for 2010 and 2011 that we entered into during the first nine months of 2009.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of September 30, 2009, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

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In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)	Natural Gas Derivative Contracts Receipt/ (Payment)
Based on:		
NYMEX futures prices as of September 30, 2009	$ (35,362)	$ (14,010)
10% increase in prices	(82,121)	(29,631)
10% decrease in prices	1,120	1,600

Critical Accounting Policies

For a discussion of our critical accounting policies, which are related to property, plant and equipment, depletion and depreciation, oil and natural gas reserves, asset retirement obligations, income taxes and hedging activities, and which remain unchanged, except as listed below, see Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2008.

Fair Value Estimates

The FASC defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Level 1 inputs are given the highest priority in the fair value hierarchy, as they represent observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date, while Level 3 inputs are given the lowest priority, as they represent unobservable inputs that are not corroborated by market data. Valuation techniques that maximize the use of observable inputs are favored. See Note 7 to the Unaudited Condensed Consolidated Financial Statements for disclosures regarding our recurring fair value measurements.

Significant uses of fair value measurements include:

- allocation of the purchase price paid to acquire businesses to the assets acquired and liabilities assumed in those acquisitions,
- assessment of impairment of long-lived assets,
- assessment of impairment of goodwill, and
- recorded value of derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations, the purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. FASC Business Combinations topic defines the acquisition date as the date on which the acquirer obtains control of the acquiree, which is usually a date different than the date the economics of the acquisition are established between the acquirer and the acquiree. FASC Fair Value Measurements and Disclosures topic defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (often referred to as the exit price). A fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value unless those assumptions are consistent with market participant views.

The excess of the purchase price over the fair value of the net tangible and identifiable intangible assets acquired is recorded as goodwill. A significant amount of judgment is involved in estimating the individual fair values involving property, plant and equipment and identifiable intangible assets. We use all available information to make these fair value determinations and, for certain acquisitions, engage third-party consultants for assistance.

The fair values used to allocate the purchase price of an acquisition are often estimated using the expected present value of future cash flows method, which requires us to project related future cash inflows and outflows and apply an appropriate discount rate. The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value.

Impairment Assessment of Goodwill

We test goodwill for impairment annually during the fourth quarter, or between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The need to test for impairment can be based on several indicators, including a significant reduction in prices of oil or natural gas, a full-cost ceiling write-down of oil and natural gas properties, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment.

Goodwill is tested for impairment at the reporting unit level. Denbury applies SEC full-cost accounting rules, under which the acquisition cost of oil and gas properties are recognized on a cost center basis (country), of which Denbury has only one cost center (United States). Goodwill is assigned to this single reporting unit.

Fair value calculated for the purpose of testing for impairment of our goodwill is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. A significant amount of judgment is involved performing these fair value estimates for goodwill since the results are based on forecasted assumptions. Significant assumptions include projections of future oil and natural gas prices, projections of estimated quantities of oil and natural gas reserves, projections of future rates of production, timing and amount of future development and operating costs, projected availability and cost of CO_2, projected recovery factors of tertiary reserves, and risk-adjusted discount rates. We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from those projections.

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in this Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future sources of capital or bank financing arrangements, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, anticipate projected, should, assume, believe, target or other words that convey the uncertainty of future events or outcome Such forward-looking information is based upon management s current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company s financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company s oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services, the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks, requirements for capital, its availability or its cost, general economic conditions, competition and government regulations, unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company s other public reports, filings and public statements.

DENBURY RESOURCES INC.

Management s Discussion and Analysis of Financial Condition and Results of Operations

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The information required by Item 3 is set forth under Market Risk Management in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer. Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting There have been no changes in the Company s internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

Information with respect to this item has been incorporated by reference from our Form 10-K for the year ended December 31, 2008. There have been no material developments in such legal proceedings since the filing of such Form 10-K, with the following exceptions: (1) the counterclaim described under Item 1A in Part II of our June 30, 2009 Form 10-Q related to natural gas processing and gathering agreements has since been withdrawn; and (2) during the first week of November 2009, we have been advised that several class action complaints have been filed against Encore Acquisition Company (Encore) and their directors in connection with our execution of a definitive merger agreement with Encore on October 31, 2009 (as discussed under Management s Discussion and Analysis herein), and that we have also been named in such suits, although we have not received service of process in any such case.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of our Form 10-K for the year ended December 31, 2008. There have been no material changes to the risk factors since the filing of such Form 10-K, although in connection with our execution of a definitive merger agreement with Encore on October 31, 2009 (as referenced above) our conduct pending closure of such merger or the consequences of such merger may give rise to additional risks beyond those stated in such Form 10-K, with any such risks to be addressed in detail in the registration statement on Form S-4 which we will file with the Commission relating to such merger.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plan Or Programs
July 1 through 31, 2009	605	$13.74		

August 1 through 31, 2009	142,306	$16.43
September 1 through 30, 2009	6,852	$15.06
Total	149,763	$16.36

These shares were purchased from employees of Denbury who delivered shares to the company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares.

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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

Exhibits:

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*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	The following financial statements from the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Comprehensive Operations.

* Filed herewith.

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SIGNATURES

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

DENBURY RESOURCES INC.
(Registrant)

By: /s/ Mark C. Allen
Mark C. Allen
Sr. Vice President and Chief Financial Officer

By: /s/ Alan Rhoades
Alan Rhoades
Vice President, Accounting

Date: November 9, 2009