DENBURY RESOURCES INC
Form 10-Q
May 11, 2009

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 March 31, 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 o 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 April 30, 2009
Common Stock, $.001 par value	248,856,000

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Part I. Financial Information
Item 1. Financial Statements

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

	March 31, 2009	Decembe 31, 2008
Assets		
rrent assets		
sh and cash equivalents	$ 18,207	$ 17,06
crued production receivable	75,138	67,80
ade and other receivables, net of allowance of $392 and $377	95,435	80,57
rivative assets	172,732	249,74
tal current assets	361,512	415,19
operty and equipment		
l and natural gas properties (using full cost accounting)		
oved	3,569,837	3,386,60
nevaluated	245,599	235,40
$)_2$ properties, equipment and pipelines	1,063,200	899,54
her	74,136	70,32
ss accumulated depletion, depreciation and impairment	(1,651,187)	(1,589,68
t property and equipment	3,301,585	3,002,19
posits on properties under option or contract		48,91
her assets	133,061	123,36
odwill	138,737	
tal assets	$ 3,934,895	$ 3,589,67
Liabilities and Stockholders Equity		
rrent liabilities		
counts payable and accrued liabilities	$ 130,610	$ 202,63
l and gas production payable	85,829	85,83
rivative liabilities	18,113	
ferred revenue Genesis	4,070	4,07
ferred tax liability	53,188	89,02
rrent maturities of long-term debt	4,562	4,50
tal current liabilities	296,372	386,06
ng-term liabilities		
ng-term debt Genesis	250,662	251,04
ng-term debt	1,006,987	601,72
set retirement obligations	46,394	43,35

ferred revenue Genesis	18,974	19,95
ferred tax liability	458,010	433,21
rivative liabilities	11,224	
her	14,639	14,25
tal long-term liabilities	1,806,890	1,363,53
ockholders equity		
eferred stock, $.001 par value, 25,000,000 shares authorized; none issued and outstanding		
mmon stock, $.001 par value, 600,000,000 shares authorized; 249,181,816 and 248,005,874 shares issued at arch 31, 2009 and December 31, 2008, respectively	249	24
id-in capital in excess of par	716,375	707,70
tained earnings	1,121,278	1,139,57
cumulated other comprehensive loss	(609)	(62
easury stock, at cost, 376,063 and 446,287 shares at March 31, 2009 and December 31, 2008, respectively	(5,660)	(6,83
tal stockholders equity	1,831,633	1,840,06
tal liabilities and stockholders equity	$ 3,934,895	$ 3,589,67

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Revenues and other income		
Oil, natural gas and related product sales	$ 168,069	$ 313,197
CO_2 sales and transportation fees	3,165	2,851
Interest income and other	2,525	1,287
Total revenues	173,759	317,335
Expenses		
Lease operating expenses	74,950	66,001
Production taxes and marketing expenses	7,000	15,186
Transportation expense Genesis	2,192	1,550
CO_2 operating expenses	1,300	1,143
General and administrative	22,655	16,005
Interest, net of interest capitalized of $12,373 and $7,266, respectively	12,197	4,941
Depletion, depreciation and amortization	61,925	49,839
Commodity derivative expense	20,515	46,781
Total expenses	202,734	201,446
Income (loss) before income taxes	(28,975)	115,889
Income tax provision (benefit)		
Current income taxes	173	21,236
Deferred income taxes	(10,851)	21,651
Net income (loss)	$ (18,297)	$ 73,002
Net income (loss) per common share basic	$ (0.07)	$ 0.30
Net income (loss) per common share diluted	$ (0.07)	$ 0.29
Weighted average common shares outstanding		
Basic	245,573	242,757
Diluted	245,573	252,109

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Cash flow from operating activities:		
Net income (loss)	$ (18,297)	$ 73,002
Adjustments needed to reconcile to net cash flow provided by operations:		
Depreciation, depletion and amortization	61,925	49,839
Deferred income taxes	(10,851)	21,651
Deferred revenue Genesis	(983)	(1,044)
Stock-based compensation	5,537	3,886
Non-cash fair value derivative adjustments	106,380	39,128
Other	(551)	281
Changes in assets and liabilities relating to operations:		
Accrued production receivable	(7,333)	(6,034)
Trade and other receivables	(15,590)	(8,359)
Other assets	(26)	(838)
Accounts payable and accrued liabilities	(10,192)	16,486
Oil and gas production payable	(5)	17,634
Other liabilities	2,605	625
Net cash provided by operating activities	112,619	206,257
Cash flow used for investing activities:		
Oil and natural gas capital expenditures	(98,325)	(156,302)
Acquisitions of oil and natural gas properties	(199,163)	(402)
Change in accrual for capital expenditures	(64,922)	(9,609)
CO_2 capital expenditures, including pipelines	(163,655)	(42,526)
Distributions from Genesis	2,312	1,250
Net proceeds from sales of oil and gas properties and equipment	18,357	54,225
Net purchases of other assets	(4,112)	(10,279)
Other	(31)	(45)
Net cash used for investing activities	(509,539)	(163,688)
Cash flow from financing activities:		
Bank repayments	(330,000)	(91,000)
Bank borrowings	345,000	52,000
Income tax benefit from equity awards	668	5,414
Issuance of subordinated debt	389,827	
Issuance of common stock	3,455	5,154
Costs of debt financing	(9,970)	
Other	(922)	(205)

Net cash provided by (used for) financing activities		398,058		(28,637)
Net increase in cash and cash equivalents		1,138		13,932
Cash and cash equivalents at beginning of period		17,069		60,107
Cash and cash equivalents at end of period	$	18,207	$	74,039
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest	$	7,215	$	2,050
Cash paid (refunded) during the period for income taxes		(3,833)		2,630
Interest capitalized		12,373		7,266

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Net income (loss)	$ (18,297)	$ 73,002
Other comprehensive income (loss), net of income tax:		
Change in fair value of interest rate lock contracts designated as a hedge, net of tax of $- and ($252), respectively		(480)
Interest rate lock derivative contracts reclassified to income, net of taxes of $11 and $11, respectively	18	18
Comprehensive income (loss)	$ (18,279)	$ 72,540

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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 March 31, 2009 and the consolidated results of its operations and cash flows for the three month periods ended March 31, 2009 and 2008. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

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, non-vested stock appreciation rights (SARs), non-vested restricted stock and any other convertible securities outstanding. For the three months ended March 31, 2009 and 2008, there were no adjustments to net income for purposes of calculating diluted net income per common share. Since we were in a loss position for the three months ended March 31, 2009, the potentially dilutive securities were excluded from the calculation of diluted earnings per share as the shares would have had an anti-dilutive effect. 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 month periods ended March 31, 2009 and 2008.

	Three Months Ended March 31,	
In thousands	2009	2008
Weighted average common shares basic	245,573	242,757
Potentially dilutive securities:		
Stock options and SARs		7,995
Restricted stock		1,357
Weighted average common shares diluted	245,573	252,109

The weighted average common shares basic amount excludes 2.9 million shares in 2009 and 2.7 million shares in 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 per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating weighted average common shares diluted, 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. The dilution impact of these shares on our earnings per share calculation may increase in future periods, depending on the market price of our common stock during those periods.

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Notes to Unaudited Condensed Consolidated Financial Statements

For the three months ended March 31, 2009 and 2008, stock options and SARs to purchase approximately 9.0 million and 693,000 shares of common stock, respectively, were outstanding but excluded from the diluted net income (loss) per common share calculation, as their exercise prices exceeded the average market price of the Company s common stock during this period and would be anti-dilutive to the calculation or the Company was in a net loss position and the shares would be anti-dilutive.

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 March 31, 2009 and December 31, 2008, we had $553.3 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. These costs of CO_2 pipelines under construction were not being depreciated at March 31, 2009 or December 31, 2008. Depreciation will commence as each pipeline is placed into service.

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 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 each 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.

Recently Adopted Accounting Pronouncements

Business Combinations. In December 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised 2008), Business Combinations. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. We adopted this statement on January 1, 2009. We have applied SFAS 141(R) to an acquisition that we made during the first quarter (see Note 2 Hastings Field Acquisition).

Equity Method Accounting. In November 2008, the FASB reached a consensus on Emerging Issues Task Force (EITF) Issue No. 08-6, Equity Method Investment Accounting Considerations (EITF 08-6), which was issued to clarify how the application of equity method accounting will be affected by SFAS No. 141(R) and SFAS No. 160. EITF 08-6 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 the use of the impairment model under Accounting Principles Board (APB) Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock (APB No. 18). 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 Issue was effective January 1, 2009, and applies prospectively.

Noncontrolling Interests. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 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. SFAS No. 160 also establishes disclosure requirements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted SFAS No. 160 on January 1, 2009. Since we currently do not have any noncontrolling interests, the adoption of SFAS No. 160 did not have any impact on our financial position or results of operations.

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Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of SFAS No. 133. SFAS No. 161 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. SFAS No. 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS No. 133 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 of SFAS No. 161 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. On February 12, 2008, the FASB issued FASB Staff Position (FSP) SFAS No. 157-2 which delayed the effective date of SFAS No. 157 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 FSP FASB No. 157-2 on January 1, 2009. The adoption of this FSP did not have any impact on our financial position or results of operations.

Recently Issued Accounting Pronouncements

In April 2009, the FASB issued three FASB Staff Positions to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FSP SFAS No. 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. FSP SFAS No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, enhances consistency in financial reporting by increasing the frequency of fair value disclosures, FSP SFAS No. 115-2 and SFAS No. 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. These three FSP s are effective for interim and annual periods ending after June 15, 2009. We are currently evaluating the impact the new rules may have on our financial condition or results of operations.

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 that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies that have an audit performed on their reserves to report the independence and qualifications of the auditor of the reserve estimates, and to 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 calculated using an average price based upon the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. We are currently evaluating the impact the new rules may have on our financial condition or results of operations.

Note 2. 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 totalling $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 deposit plus purchase price, adjusted for interim net cash flows between the effective date and closing date of the acquisition (including minor purchase price adjustments), totaled approximately $248.2 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

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Notes to Unaudited Condensed Consolidated Financial Statements

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 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 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 SFAS No. 141(R), Business Combinations. As such, we estimated the fair value of this property as of the acquisition date, as defined in SFAS No. 141(R) to be the date on which the acquirer obtains control of the acquiree, which for this acquisition is February 2, 2009 (the closing date). SFAS No. 157, Fair Value Measurements, 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). Further, SFAS No. 157 emphasizes that a fair value measurement should be 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 that the fair value of these properties on the acquisition date to be approximately $107.0 million. This measurement resulted in the recognition of goodwill totaling $138.7 million. SFAS No. 141(R) 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 and the acquisition date of February 2, 2009. 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, SFAS No. 157 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 SFAS No. 157 refers to 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 $107.0 million to evaluated properties in the full cost pool and $2.4 million (net) 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 $138.7 million was assigned to this single reporting unit. All of the goodwill is deductible for tax purposes as property cost. This purchase price allocation is preliminary and subject to adjustment as the final closing statement is not complete.

The transaction related costs (legal, accounting, due diligence, etc.) have been expensed in accordance with the provisions of SFAS No. 141(R). 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 month periods ended March 31, 2009 or 2008.

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Notes to Unaudited Condensed Consolidated Financial Statements

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.

The following table summarizes the changes in our asset retirement obligations for the three months ended March 31, 2009.

Amounts in thousands	Three Months Ended March 31, 2009
Beginning asset retirement obligation	$ 45,064
Liabilities incurred and assumed during period	2,513
Revisions in estimated retirement obligations	504
Liabilities settled during period	(971)
Accretion expense	827
Ending asset retirement obligation	$ 47,937

At March 31, 2009 and December 31, 2008, $1.5 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 three months ended March 31, 2009 were primarily related to the Hastings Field acquisition (see Note 2 Hastings Field Acquisition). We have 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 $7.4 million at March 31, 2009 and December 31, 2008, and are included in Other assets in our Unaudited Condensed Consolidated Balance Sheets.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Notes Payable and Long-term Indebtedness

Amounts in thousands	March 31, 2009	December 31, 2008
9.75% Senior Subordinated Notes due 2016	$ 420,000	$
Discount on Senior Subordinated Notes due 2016	(29,637)	
7.5% Senior Subordinated Notes due 2015	300,000	300,000
Premium on Senior Subordinated Notes due 2015	578	599
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(777)	(826)
NEJD financing Genesis	172,899	173,618
Free State financing Genesis	77,246	76,634
Senior bank loan	90,000	75,000
Capital lease obligations Genesis	4,360	4,544
Capital lease obligations	2,542	2,705
Total	1,262,211	857,274
Less current obligations	4,562	4,507
Long-term debt and capital lease obligations	$ 1,257,649	$ 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 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 Hastings Field Acquisition). 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.

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 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, subsequent to March 31, 2009 we obtained an amendment to the credit agreement from our lenders to explicitly permit these guarantees and waive any possible previous technical violations of this provision.

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

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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. Our investment in Genesis is included in Other Assets in our Unaudited Condensed Consolidated Balance Sheets. Denbury received cash distributions from Genesis of $2.3 million and $1.3 million during the three months ended March 31, 2009 and 2008, respectively. We also received $51,000 and $30,000 during the three months ended March 31, 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.

At March 31, 2009, the balance of our equity investment in Genesis was $79.6 million. Based on quoted market values of Genesis publicly traded limited partnership units at March 31, 2009, the estimated market value of our publicly traded common units of Genesis was approximately $41.2 million. Since the general partner units we hold are not publicly traded, there is not a readily available market value for these units. Due to the capital market conditions during the latter part of 2008 and in 2009, we have reviewed the value of our investment in Genesis as of March 31, 2009 for impairment. Based upon this review, and the current and future expected cash flows of Genesis, we do not believe the investment balance is impaired.

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. The compensation agreements provide Genesis management with the ability to earn up to an approximate 17% interest in the incentive distributions that Genesis Energy, LLC will receive from Genesis. These awards have a mandatory redemption feature upon termination of employment that requires a cash payment to be made by Genesis Energy, LLC (guaranteed by us) to the holder of the award. The awards have a graded vesting of 25% per year from the date of the award. Under the provisions of SFAS 123(R), the estimated fair value of the mandatory redemption feature of these awards will be recorded as a liability at each reporting date, initially recognized over the four year vesting period on an accelerated basis due to the graded vesting feature, with the changes in this liability recorded as compensation expense in General and administrative expenses in our Unaudited Condensed Consolidated Statement of Operations. As of March 31, 2009, we had approximately $2.5 million recorded as an estimated long-term fair value liability for these awards in our Unaudited Condensed Consolidated Balance Sheet which does not represent the contractual amount payable under these awards at March 31, 2009. During the three months ended March 31, 2009, we recorded approximately $2.6 million in General and administrative expenses on our Unaudited Condensed Consolidated Statement of Operations of which $2.5 million was associated with the estimated fair value of these awards and $80,000 was for cash payments made under these awards.

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 March 31, 2009, we have recorded $172.9 million for the NEJD financing and $77.2 million for the Free State financing as debt, $3.1 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. In the first three months of 2009 and 2008, we expensed

$2.2 million and $1.5 million, respectively, for these transportation services.

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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. The pipelines held under these capital leases are classified as property and equipment and are amortized using the straight-line method over the lease terms. Lease amortization is included in depreciation expense. The related obligations are recorded as debt. At March 31, 2009 and December 31, 2008 we had $4.4 million and $4.5 million, respectively, of capital lease obligations with Genesis recorded as liabilities in our Unaudited Condensed Consolidated Balance Sheets.

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 March 31, 2009 and December 31, 2008 $23.0 million and $24.0 million, respectively, was recorded as deferred revenue, of which $4.1 million was included in current liabilities at both March 31, 2009 and December 31, 2008. We recognized deferred revenue of $1.0 million for each of the three months ended March 31, 2009 and 2008, 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 $1.2 million and $1.3 million for the three months ended March 31, 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 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, and in order to protect our liquidity in the event that commodity prices continue to decline, during early October 2008 we purchased oil derivative contracts for 2009 with a floor price of $75 per Bbl and a ceiling price of $115 per Bbl for total consideration of $15.5 million. In March 2009, we entered into crude oil swap contracts covering 25,000 Bbls/d for the first quarter of 2010 at a weighted average price of $51.85 per barrel, and crude oil collar contracts covering 25,000 Bbls/d for the second quarter of 2010 with a weighted average floor price of $50.00 per Bbl and a weighted average ceiling price of $74.60 per Bbl. Also during March 2009, we entered into natural gas derivative swap contracts covering 55,000 MMBtu/d for 2010 at a weighted average price of $5.66 per MMBtu, and 40,000 MMBtu/d for 2011 at a weighted average price of $6.21 per MMBtu.

At March 31, 2009, our oil and natural gas derivative contracts were recorded at their fair value, which was a net asset of $143.4 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. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts as required by SFAS No. 157. We have measured the nonperformance risk based upon credit default swaps or credit spreads. At March 31, 2009 and December 31, 2008, the fair value of our oil and natural gas derivative contracts was reduced by $1.7 million and $3.7 million, respectively, for estimated nonperformance risk.

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

	Three Months Ended March 31,	
Amounts in thousands	2009	2008
Receipt (payment) on settlements of derivative contracts oil	$ 85,836	$ (7,392)
Receipt (payment) on settlements of derivative contracts gas		(656)
Fair value adjustments to derivative contracts expense	(106,351)	(38,733)
Commodity derivative expense	$ (20,515)	$ (46,781)

Fair Value of Crude Oil Derivative Contracts Not Classified as Hedging Instruments under SFAS No. 133:

	NYMEX Contract Prices Per Bbl				Estimated Fair Value Asset (Liability)	
			Collar Prices		March 31,	December 31,
Type of Contract and Period	Bbls/d	Swap Price	Floor	Ceiling	2009	2008
					(In thousands)	
Collar Contracts						
April 2009 Dec. 2009	30,000		$75.00	$115.00	$172,732	$249,746
April 2010 June 2010	5,000		50.00	76.00	(94)	
April 2010 June 2010	10,000		50.00	73.15	(884)	
April 2010 June 2010	5,000		50.00	76.40	(49)	
April 2010 June 2010	5,000		50.00	74.30	(297)	
Swap Contracts						
Jan. 2010 March 2010	6,667	$52.50			(4,305)	
Jan. 2010 March 2010	3,333	52.20			(2,237)	
Jan. 2010 March 2010	5,000	52.10			(3,398)	
Jan. 2010 March 2010	5,000	50.90			(3,907)	
Jan. 2010 March 2010	5,000	51.45			(3,674)	

Fair Value of Natural Gas Derivative Contracts Not Classified as Hedging Instruments under SFAS No. 133:

	NYMEX Contract Prices Per MMBtu/d		Estimated Fair Value Asset (Liability)	
			March 31,	December 31,
Type of Contract and Period	MMBtu/d	Swap Price	2009	2008
			(In thousands)	
Swap Contracts				
Jan. 2010 Dec. 2010	45,000	$5.67	$(3,826)	$
Jan. 2010 Dec. 2010	10,000	5.65	(925)	
Jan. 2011 Dec. 2011	10,000	6.27	(1,254)	

Jan. 2011	Dec. 2011	10,000	6.25	(1,301)
Jan. 2011	Dec. 2011	20,000	6.16	(3,186)

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Notes to Unaudited Condensed Consolidated Financial Statements

Additional Disclosures about Derivative Instruments:

At March 31, 2009 and December 31, 2008, we had derivative financial instruments under SFAS No. 133 recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) March 31, 2009	December 31, 2008
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative Asset			
Crude Oil contracts	Derivative assets current	$ 172,732	$ 249,746
Derivative Liability			
Crude Oil contracts	Derivative liability current	(17,521)	
Natural Gas contracts	Derivative liability current	(592)	
Crude Oil contracts	Derivative liability long-term	(1,324)	
Natural Gas contracts	Derivative liability long-term	(9,900)	
Total derivatives not designated as hedging instruments		$ 143,395	$ 249,746

For the three months ended March 31, 2009 and 2008, the effect on income of derivative financial instruments under SFAS No. 133 was as follows:

Type of Contract	Location of Gain/(Loss) Recognized in Income	Amount of Gain / (Loss) Recognized in Income For Three Months Ended March 31, 2009	March 31, 2008
		(In thousands)	
Derivatives not designated as hedging instruments:			
Commodity Contracts			
Crude Oil Contracts	Commodity derivative expense	$ (10,025)	$ (4,754)
Natural Gas Contracts	Commodity derivative expense	(10,490)	(42,027)
Total derivatives not designated as hedging instruments		$ (20,515)	$ (46,781)

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 7. Fair Value Measurements

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 March 31, 2009.

	Fair Value Measurements at March 31, 2009 Using:			
Amounts in thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Oil and natural gas derivative contracts	$	$ 172,732	$	$ 172,732
Liabilities:				
Oil and natural gas derivative contracts		(29,337)		(29,337)
Total	$	$ 143,395	$	$ 143,395

See Note 6, Derivative Instruments and Hedging Activities for further information about these contracts.

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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Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Balance Sheets

	March 31, 2009				
Amounts 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	$ 439,078	$ 354,030	$ 16,045	$ (447,641)	$ 361,512
Property and equipment		3,228,472	73,113		3,301,585
Investment in subsidiaries (equity method)	1,353,882		1,297,345	(2,651,227)	
Other assets	741,289	205,259	56,169	(730,919)	271,798
Total assets	$ 2,534,249	$ 3,787,761	$ 1,442,672	$ (3,829,787)	$ 3,934,895
Liabilities and Stockholders Equity					
Current liabilities	$ 11,675	$ 646,475	$ 85,862	$ (447,641)	$ 296,372
Long-term liabilities	690,941	1,843,941	2,928	(730,919)	1,806,890
Stockholders equity	1,831,633	1,297,345	1,353,882	(2,651,227)	1,831,633
Total liabilties and stockholders equity	$ 2,534,249	$ 3,787,761	$ 1,442,672	$ (3,829,787)	$ 3,934,895

	December 31, 2008				
Amounts 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		1,313,656	(2,685,003)	
Other assets	312,239	114,372	56,002	(310,335)	172,278
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 liabilties 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 March 31, 2009				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 10,858	$ 172,060	$ 1,699	$ (10,858)	$ 173,759
Expenses	11,673	198,964	2,955	(10,858)	202,734
Income (loss) before the following:	(815)	(26,904)	(1,256)		(28,975)
Equity in net earnings of subsidiaries	(17,482)		(16,330)	33,812	
Income (loss) before income taxes	(18,297)	(26,904)	(17,586)	33,812	(28,975)
Income tax provision (benefit)		(10,574)	(104)		(10,678)
Net income (loss)	$ (18,297)	$ (16,330)	$ (17,482)	$ 33,812	$ (18,297)

	Three Months Ended March 31, 2008				
Amounts 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	$ 311,619	$ 5,716	$ (5,625)	$ 317,335
Expenses	5,745	194,897	6,429	(5,625)	201,446
Income before the following:	(120)	116,722	(713)		115,889
Equity in net earnings of subsidiaries	73,104		73,805	(146,909)	
Income before income taxes	72,984	116,722	73,092	(146,909)	115,889
Income tax provision (benefit)	(18)	42,917	(12)		42,887
Net income	$ 73,002	$ 73,805	$ 73,104	$ (146,909)	$ 73,002

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flows

	Three Months Ended March 31, 2009				
Amounts 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	$	$ 110,784	$ 1,835	$	$ 112,619
Cash flow from investing activities	(384,328)	(509,539)		384,328	(509,539)
Cash flow from financing activities	384,328	398,058		(384,328)	398,058
Net increase (decrease) in cash		(697)	1,835		1,138
Cash, beginning of period	24	16,898	147		17,069
Cash, end of period	$ 24	$ 16,201	$ 1,982	$	$ 18,207

	Three Months Ended March 31, 2008				
Amounts 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)	$ 205,010	$ 1,257	$	$ 206,257
Cash flow from investing activities	(10,541)	(163,688)		10,541	(163,688)
Cash flow from financing activities	10,541	(28,637)		(10,541)	(28,637)
Net increase (decrease) in cash	(10)	12,685	1,257		13,932
Cash, beginning of period	34	58,343	1,730		60,107
Cash, end of period	$ 24	$ 71,028	$ 2,987	$	$ 74,039

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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 reserves of carbon dioxide (CO_2) used for tertiary oil recovery east of the Mississippi River, own significant operating acreage in the Barnett Shale play near Fort Worth, Texas, and properties in 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 operations. 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 Aledo, Texas.

Operating Highlights. During the first quarter of 2009 we recorded a net loss of $18.3 million, our first quarterly loss in ten years, as compared to net income of $73.0 million in the first quarter of 2008. Although we achieved record oil and natural gas production during the first quarter of 2009, lower commodity prices reduced our revenues by approximately $200.4 million, and we recorded a non-cash fair value charge on our derivative commodity contracts of $106.4 million (approximately $65.9 million after tax).

Our oil and natural gas production for the first quarter of 2009 averaged 53,408 BOE/d, a 19% increase over first quarter 2008 levels, and an 11% sequential increase over levels in the fourth quarter of 2008. Our production growth was primarily due to production increases in both our tertiary oil fields and the Barnett Shale, and the volumes added by the Hastings Field acquisition that we completed in early February 2009 (see Purchase of Hastings Field below). Our tertiary oil production averaged 22,583 BOE/d during the first quarter of 2009, a 32% increase over the 17,156 BOE/d average for tertiary production in the first quarter of 2008, and a 3% increase over the 21,874 BOE/d average during the fourth quarter of 2008. Production in the Barnett Shale increased to 14,932 BOE/d for the first quarter of 2009, compared to 12,801 BOE/d during the first quarter of 2008, a 17% increase year-over-year, due primarily to additional sales of natural gas liquids that were produced during the third and fourth quarters of 2008, but not sold until the first quarter of 2009 due to plant shutdowns caused by Hurricane Ike. The acquisition of Hastings Field added 1,562 BOE/d to our first quarter 2009 production average. (See Results of Operations Operating Results Production for further discussion on the changes in our production volumes).

Despite the increase in our oil and natural gas production volumes in the first quarter of 2009, our oil and natural gas revenues were 46% lower in the first quarter of 2009 than in the prior year first quarter, as our average price received on a per BOE basis was approximately 54% lower in the current year period. The commodity price volatility, which began during the second half of 2008, continued through the first quarter of 2009. NYMEX oil prices moved from $44.60 per barrel at December 31, 2008 to as low as $34.00 per barrel in mid-February, and up to $49.66 per barrel as of March 31, 2009. NYMEX natural gas prices have continued their downward trend, falling from $5.62 per Mcf at December 31, 2008 to $3.78 per Mcf as of March 31, 2009.

Cash settlements on our oil commodity derivative contracts, which are not included in our oil and natural gas revenues, were $85.8 million received in the first quarter of 2009, as compared to a cash payment of $8.0 million in the first quarter of 2008. The non-cash fair value adjustments associated with our derivative contracts resulted in a $106.4 million charge in the first quarter of 2009 versus $38.7 million in the 2008 period.

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

Our lease operating expenses on a gross basis for the first quarter of 2009 were approximately 14% higher than in the first quarter of 2008, but approximately 6% lower than in the fourth quarter of 2008. On a per BOE basis, our lease operating expenses were approximately 3% lower than in the first quarter of 2008 and approximately 13% lower than in the fourth quarter of 2008. With the lower commodity price environment, we have focused our efforts on improving our operating efficiency. These efforts, along with the reduction in our cost of CO_2 due to lower oil prices and higher production volumes, have resulted in lower per BOE lease operating costs in the first quarter of 2009. Our gross general and administrative costs were approximately $6.7 million (42%) higher than in the first quarter of 2008, due primarily to higher employee costs, and the expensing of $2.6 million associated with our compensation arrangement for certain management of Genesis (see further discussion below under Results of Operations Production Expenses and Results of Operations General and Administrative Expenses). Interest expense also increased in the first quarter of 2009 primarily due to higher average debt levels and a higher average cost of money (i.e. higher interest rates), partially offset by higher levels of capitalized interest during the first quarter of 2009.

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 1,562 BOE/d during the first quarter of 2009, representing approximately two months of production.

We have recorded the acquisition of Hastings Field in accordance with SFAS No. 141(R), Business Combinations, which became effective for acquisitions after December 31, 2008. Based on these new rules, we have allocated $107.0 million of the $248.2 million adjusted purchase price to proved properties, approximately $2.4 million to land, oilfield equipment and other related assets, and the remaining $138.7 million to goodwill. See further discussion on this acquisition in Note 2 to the Unaudited Condensed Consolidated Financial Statements.

Management Succession Plan. On February 5, 2009, our Board of Directors adopted a management succession plan under which our current executive officers will assume new roles on or about June 30, 2009. Gareth Roberts, the Company s founder, will relinquish his position as President and CEO and become Co-Chairman of the Board of Directors and will assume a non-officer role as the Company s Chief Strategist. Phil Rykhoek, currently Senior Vice President and Chief Financial Officer, will become CEO; Tracy Evans, currently Senior Vice President Reservoir Engineering, will become President and Chief Operating Officer; and Mark Allen, currently Vice President and Chief Accounting Officer, will become Senior Vice President and Chief Financial Officer.

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.

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 which began during mid-2008, we have taken additional measures during the first quarter of 2009 to improve our liquidity. During February 2009, we issued $420 million of 9.75% Senior Subordination Notes, and in March 2009 we entered into additional commodity derivative contracts for 2010 and 2011 to protect our cash flow.

We used the $381.4 million proceeds from the Notes issuance to repay the majority of our then outstanding bank debt, freeing up our credit line for future capital needs. The new commodity derivative contracts include crude oil swaps covering 25,000 Bbls/d during the first quarter of 2010 at a weighted average price of $51.85 per barrel, crude oil collars covering

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

25,000 Bbls/d during the second quarter of 2010 with a floor price of $50.00 per barrel and a weighted average ceiling price of $74.60 per barrel, natural gas swaps for calendar year 2010 covering 55,000 MMBtu/d at a weighted average price of $5.66 per MMBtu and natural gas swaps for calendar year 2011 covering 40,000 MMBtu/d at a weighted average price of $6.21 per MMBtu.

We currently estimate our 2009 capital spending will be approximately $750 million, plus $201 million for the already closed Hastings Field acquisition. Our current 2009 capital budget includes approximately $485 million relating to 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 May 8, 2009, we have completed approximately $18 million of these leases, and expect to close on an additional $20 million around mid-year. If we do not enter into $100 million of operating leases during 2009, our capital expenditures would increase accordingly, and we would anticipate funding those additional capital expenditures with our bank credit line.

The 2009 budget incorporates significantly reduced spending in the Barnett Shale and in other conventional areas such as the Heidelberg Selma Chalk, and a slower development program for our tertiary operations. Based on our current cash flow projections using $50.00 per barrel for oil and $5.00 per Mcf for natural gas prices, and including the expected cash settlements on our 2009 oil derivative contracts, we anticipate our projected 2009 capital expenditures 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. We have funded a portion of this shortfall with the approximately $381.4 million of net proceeds from our February 2009 subordinated debt issuance, and anticipate funding the remainder of this shortfall under our bank credit line.

As part of our semi-annual bank review, on April 1, 2009 our borrowing base and commitment amount were reaffirmed at $1.0 billion 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 a total bank debt balance by the end of 2009 of between $150 million and $250 million, leaving us $500 million to $600 million of availability on our $750 million commitment amount.

We may raise additional capital during 2009 if it is possible to do so in a reasonably economic manner. Such additional capital sources could include the sale or joint venture of assets, a volumetric production payment, additional operating leases, or other options that become available during the year. We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital 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 Operation- Off-Balance Sheet Arrangements Commitments and Obligations in our 2008 Form 10-K for further information regarding these commitments).

Based on our long-term models, we expect our future capital spending needs to be less in the future than they have been in recent years, excluding any potential acquisitions. Therefore, if commodity prices remain at current levels after 2009, we anticipate that we will be able to match our capital spending with our projected cash flow from operations to preserve our liquidity to the extent we deem necessary, although any such spending reductions would most likely lower our anticipated rate of production growth.

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Sources and Uses of Capital Resources

Capital Expenditure Summary	Three Months Ended March 31,	
Amounts in thousands	2009	2008
Oil and natural gas exploration and development		
Drilling	$ 20,588	$ 67,291
Geological, geophysical and acreage	3,791	4,942
Facilities	52,964	44,342
Recompletions	16,940	33,744
Capitalized interest	4,042	5,983
Total oil and natural gas exploration and development expenditures	98,325	156,302
Oil and natural gas property acquisitions	199,163	402
Total oil and natural gas capital expenditures	297,488	156,704
CO_2 capital expenditures		
CO_2 pipelines	143,508	15,398
CO_2 producing fields	11,816	25,845
Capitalized interest	8,331	1,283
Total CO_2 capital expenditures	163,655	42,526
Total	$ 461,143	$ 199,230

Our first quarter 2009 capital expenditures were funded with $112.6 million of cash flow from operations, $15.0 million of net bank borrowings and $381.4 million of proceeds from the February 2009 issuance of 9.75% Senior Subordinated Notes. Our first quarter 2008 capital expenditures were essentially funded with $206.3 million of cash flow from operations, as the $48.9 million of proceeds from the second closing on our Louisiana property sale was used to reduce bank debt by $39.0 million during the first quarter, with the balance of funds from the property sale primarily used to fund other assets.

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 our proved reserve reports. Our derivative contracts, which are recorded at fair value in our balance sheets, 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/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.

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We currently have long-term commitments to purchase CO_2 from seven proposed gasification plants, three 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 1.0 Bcf/d to 1.7 Bcf/d. Due to the current economic conditions, the earliest we would expect any plant to be completed and providing CO_2 would be 2013, 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 sources (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 seven plants are built, the aggregate purchase obligation for this CO_2 would be around $210 million per year, assuming a $50 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 the CO_2 volumes from the seven proposed plants that we currently have contracts with. 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, including 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.

Results of Operations

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 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 plan to drill one additional CO_2 source well to further increase our production capacity and reserves. We estimate that we are currently capable of producing between 900 MMcf/d and 1 Bcf/d of CO_2. During the first quarter of 2009, our CO_2 production averaged 732 MMcf/d, as compared to an average of approximately 554 MMcf/d during the first quarter of 2008. We used 87% of this production, or 640 MMcf/d, in our tertiary operations during the first quarter of 2009, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments.

We spent approximately $0.14 per Mcf to produce our CO_2 during the first quarter of 2009, lower than our 2008 first quarter average of $0.22 per Mcf, primarily due to reduced royalty expense as a result of lower oil prices (to which royalties are principally tied) during the first quarter of 2009. Our estimated total cost per thousand cubic feet of CO_2 during the first quarter of 2009 was approximately $0.23, after inclusion of depreciation and amortization expense, also down from the 2008 first quarter average total cost of $0.30 per Mcf.

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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 have ongoing discussions with owners of existing plants of various types that emit CO_2 and we may be able to purchase their volumes. In order to capture such volumes, we (or the plant owner) would need to install additional equipment, which include 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 anticipated 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 supplies and demands.

The following table summarizes our tertiary oil production and tertiary lease operating expense per barrel for each quarter in 2008 and the first quarter 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
Phase I:					
Brookhaven	2,638	2,714	2,772	3,178	3,451
Little Creek area	1,807	1,661	1,556	1,706	1,619
Mallalieu area	6,099	6,260	5,339	5,056	4,490
McComb area	1,632	1,818	2,061	2,092	2,246
Lockhart Crossing			182	555	607
Phase II:					
Martinville	793	715	736	1,213	1,118
Eucutta	2,699	2,933	3,262	3,538	3,813
Soso	1,488	1,885	2,358	2,704	2,705
Phase III:					
Tinsley		675	1,518	1,832	2,390
Phase IV:					
Cranfield					144
Total tertiary oil production	17,156	18,661	19,784	21,874	22,583
Tertiary operating expense per Bbl	$ 20.81	$ 24.67	$ 26.81	$ 21.86	$ 20.48

Oil production from our tertiary operations averaged 22,583 BOE/d in the first quarter of 2009, a 32% increase over our first quarter 2008 tertiary production level of 17,156 BOE/d and a 3% sequential increase over the fourth quarter 2008 average tertiary production level of 21,874 BOE/d. This increase is the result of tertiary fields that commenced production after the first quarter of 2008, mainly Tinsley and Lockhart Crossing Fields, and from production increases during 2009 at almost every other tertiary field, except Little Creek and Mallalieu Fields. Little Creek is a mature field that is experiencing normal decline, and the decline at Mallalieu Field is primarily due to current CO_2 recycle volumes exceeding the plant capacity there. We are current expanding the capacity of the facility and expect it to be operational in the third or fourth quarter of 2009. Once the recycle capacity is expanded we would expect production at Mallalieu Field to plateau. We had a minimal amount of oil production from Cranfield Field during the first quarter of 2009 and we expect initial production from Heidelberg Field during the second half of 2009. We also anticipate initiating CO_2 injections at Delhi field (Phase V) during the second quarter of 2009, following the completion of the Delta Pipeline from Tinsley to Delhi Field, which is currently undergoing testing. However, we currently do not anticipate any tertiary production response at Delhi Field until the first half of 2010.

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During the first quarter of 2009, our operating costs for our tertiary properties averaged $20.48 per BOE, lower than the prior year s first quarter average of $20.81 per BOE, and our fourth quarter 2008 average of $21.86 per BOE. While costs have increased on a gross basis due to the new tertiary floods and ongoing expansion of existing floods, they have decreased on a per BOE basis due to the increased production and reductions in our CO_2 costs discussed above. For any specific field, we expect our tertiary lease operating expense per BOE to initially be high, until production increases significantly, and then level off until production begins to decline.

Operating Results

As summarized in the Overview section above and discussed in more detail below, the slight decline in overall expenses and the 19% increase in production quantities in the first quarter of 2009 as compared to the same quarter in 2008, was more than offset by decreased commodity prices, which when coupled with a $106.4 million non-cash fair value charge on our derivative contracts, result in a net loss during the first quarter of 2009.

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

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Amounts in thousands except per share and unit data	Three Months Ended March 31, 2009	2008
Operating results		
Net income (loss)	$ (18,297)	$ 73,002
Net income (loss) per common share basic	(0.07)	0.30
Net income (loss) per common share diluted	(0.07)	0.29
Cash flow from operations	112,619	206,257
Average daily production volumes		
Bbls/d	37,640	30,164
Mcf/d	94,613	88,419
BOE/d (1)	53,408	44,900
Operating revenues		
Oil sales	$ 133,265	$ 250,441
Natural gas sales	34,804	62,756
Total oil and natural gas sales	$ 168,069	$ 313,197
Oil and natural gas derivative contracts (2)		
Cash receipt (payment) on settlement of derivative contracts	$ 85,836	$ (8,048)
Non-cash fair value adjustment expense	(106,351)	(38,733)
Total expense from oil and gas derivative contracts	$ (20,515)	$ (46,781)
Operating expenses		
Lease operating expenses	$ 74,950	$ 66,001
Production taxes and marketing expenses (3)	9,192	16,736
Total production expenses	$ 84,142	$ 82,737
Non-tertiary CO_2 operating margin		
CO_2 sales and transportation fees (4)	$ 3,165	$ 2,851
CO_2 operating expenses	(1,300)	(1,143)
Non-tertiary CO_2 operating margin	$ 1,865	$ 1,708
Unit prices including impact of derivative settlements (2)		
Oil price per Bbl	$ 64.68	$ 88.55
Gas price per Mcf	4.09	7.72

Unit prices excluding impact of derivative settlements [2]				
Oil price per Bbl	$	39.34	$	91.24
Gas price per Mcf		4.09		7.80
Oil and natural gas operating revenues and expenses per BOE [1]				
Oil and natural gas revenues	$	34.97	$	76.65
Oil and natual gas lease operating expenses	$	15.59	$	16.15
Oil and natural gas production taxes and marketing expenses		1.91		4.10
Total oil and natural gas production expenses	$	17.50	$	20.25

(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 $1.0 million for both periods associated with volumetric production payments and $1.2 million and $1.3 million for 2009 and 2008, respectively, of transportation

income, both
from Genesis.

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Production: Average daily production by area for each of the quarters of 2008 and the first quarter 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
Tertiary oil fields	17,156	18,661	19,784	21,874	22,583
Mississippi non-CO_2 floods	12,128	11,617	11,694	12,150	11,904
Texas	13,522	14,068	12,701	12,576	17,063
Onshore Louisiana	905	663	512	418	708
Alabama and other	1,189	1,296	1,222	1,219	1,150
Total Company	44,900	46,305	45,913	48,237	53,408

As outlined in the above table, production in the first quarter of 2009 increased 19% over first quarter 2008 levels and 11% over fourth quarter 2008 levels, primarily due to increased production from our tertiary operations and the Barnett Shale, and due to the acquisition of Hastings field in February, 2009. The increase in tertiary operations is discussed above under Results of Operations CO_2 Operations .

Our Texas Barnett Shale production increased 2,131 BOE/d (17%) from the prior year s first quarter level and increased 2,699 BOE/d (22%) over the fourth quarter of 2008 production level, primarily due to additional sales of natural gas liquids that were produced during the third and fourth quarters of 2008, but not sold until the first quarter of 2009 due to plant shutdowns caused by Hurricane Ike. Generally, throughout 2008 and continuing into the first quarter of 2009, our production in the Barnett area has been relatively flat, with minor changes up or down each quarter. As a result of our curtailed drilling there in 2009, we expect our Barnett Shale production to gradually decrease throughout the remainder of 2009. Hastings Field, acquired in early February 2009, contributed 1,562 BOE/d to our Texas production during the first quarter 2009.

Production from our Mississippi-non-CO_2 floods is approximately the same as in the prior year s first quarter as this area is on a gradual decline due to normal depletion; however, our drilling activity in the Sharon Field (natural gas) in the latter part of 2008 has helped offset the gradual declines in oil production.

Oil and Natural Gas Revenues: Due to the extreme volatility in oil and natural gas prices, our oil and natural gas revenues dropped sharply in the first quarter of 2009 as compared to these revenues in the first quarter of 2008, offset in part by a steady increase in production, as seen in the following table:

Amounts in thousands	Three Months Ended March 31, 2009 vs. 2008	
	Increase (Decrease) In Revenues	Percentage Increase (Decrease) In Revenues
Change in revenues due to:		
Increase in production	$ 55,254	18%
Decrease in commodity prices	(200,382)	(64%)
Total decrease in revenues	$(145,128)	(46%)

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Excluding any impact of our hedging activities, our net realized commodity prices and NYMEX differentials were as follows during the first three months of 2009 and 2008.

	Three Months Ended March 31,	
	2009	2008
Net Realized Prices:		
Oil price per Bbl	$39.34	$91.24
Natural gas price per Mcf	4.09	7.80
Price per BOE	34.97	76.65
NYMEX Differentials:		
Oil per Bbl	$ (3.99)	$ (6.50)
Natural Gas per Mcf	(0.41)	(0.92)

Our Company-wide oil price NYMEX differential improved in the first quarter of 2009 as compared to the 2008 period due primarily to the decrease in oil prices, and was generally consistent with our oil price NYMEX differential of $3.59 per Bbl in the fourth quarter of 2008.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during a 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 in the above table is 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 first three months of 2009 and 2008.

	Three Months Ended March 31,			
	2009		2008	
Amounts in thousands	Non-Cash Fair Value Adjustment Income/ (expense)	Cash Settlements Receipt/ (payment)	Non-Cash Fair Value Adjustment Income/ (expense)	Cash Settlements Receipt/ (payment)
Oil derivative contracts	$ (95,861)	$85,836	$ 2,638	$(7,392)
Natural gas derivative contracts	(10,490)		(41,371)	(656)
Total	$(106,351)	$85,836	$(38,733)	$(8,048)

The change in commodity prices and the expiration of contracts cause fluctuations in the mark-to-market 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 first quarter of 2009, we recognized total non-cash fair value expense of $106.4 million. Of this amount, $77.0 million 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 first quarter of 2009 was made up of $18.9 million of charges on the oil derivative contracts we entered into in March 2009, and $10.5 million on our new natural gas swaps. (See Note 6 to the Unaudited Condensed Consolidated Financial Statements for a summary of our oil and natural gas derivative contracts.) During the first quarter of 2008, we recognized non-cash fair value income of $2.6 million on our oil derivative contracts and non-cash fair value expense of $41.4 million on our natural gas derivative contracts.

During the first quarter of 2009, we received cash settlements of $85.8 million on our oil derivative contracts. During the first quarter of 2008, we made cash payments of $7.4 million on our oil derivative contracts and $0.7 million on our natural gas derivative contracts, giving us a total change between the two periods of $93.9 million.

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Production Expenses: Our lease operating expenses increased between the comparable first quarters on a gross basis as a result of (i) our increasing emphasis on tertiary operations (see discussion of those expenses under CO_2 Operations above), (ii) increased personnel and related costs, (iii) higher electrical costs to operate our properties and (iv) increasing lease payments for certain equipment in our tertiary operating facilities. Our lease operating expenses decreased on a per BOE basis between the comparable first quarters due in part to a 19% increase in production year-over-year and in part to 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 with levels of available cash flow, 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 over time. During the first quarter of 2009, Company-wide lease operating costs averaged $15.59 per BOE, down from $16.15 per BOE during the first quarter of 2008 and down from $17.90 per BOE in the fourth quarter of 2008.

Production taxes and marketing expenses generally change in proportion to changes in commodity prices and production volumes, and therefore were lower in the first quarter of 2009 than in the comparable quarter of 2008. Transportation and plant processing fees increased approximately $0.9 million in the first quarter of 2009 as compared to those expenses in the first quarter of 2008, largely associated with incremental production and incremental plant processing fees related to our Barnett Shale production.

General and Administrative Expenses

General and administrative (G&A) expenses increased 42% between the respective first quarters as set forth below:

	Three Months Ended March 31,	
Net G&A expense (thousands)	2009	2008
Gross cash G&A expense	$ 35,367	$ 29,668
Gross stock-based compensation	6,140	4,497
Incentive compensation for Genesis management	2,593	
State franchise taxes	1,115	828
Operator labor and overhead recovery charges	(18,986)	(15,953)
Capitalized exploration and development costs	(3,574)	(3,035)
Net G&A expense	$ 22,655	$ 16,005
G&A per BOE:		
Net cash G&A expense	$ 2.86	$ 2.86
Net stock-based compensation	1.08	0.86
Incentive compensation for Genesis management	0.54	
State franchise tax	0.23	0.20
Net G&A expense	$ 4.71	$ 3.92
Employees as of March 31	817	701

Gross cash G&A expenses increased $5.7 million, or 19%, between the first quarters of 2008 and 2009. Approximately $4.6 million of the increase in gross cash G&A expenses is related to increases in compensation and personnel related costs, due primarily to the increase in the number of employees and salary increases, which we consider necessary in order to remain competitive in our industry. During 2008, we increased our employee count by 16% and we further increased our employee count by approximately 3% during the first quarter of 2009 due in part to our Hastings Field acquisition. Stock compensation expense was approximately $6.1 million for the first quarter of 2009 and $4.5 million for the first quarter of 2008.

Also adding to the year-over-year increase in net G&A expense was a $2.6 million charge relating to incentive compensation awards for the management of Genesis. 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. Based on current estimates of fair value under the provisions of SFAS 123(R), we would anticipate accruing up to $10.4 million for these awards in 2009. 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

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Transactions Genesis to the Unaudited Condensed Consolidated Financial Statements for further information regarding these incentive compensation awards.

These increases in G&A were offset in part by an increase in operator labor and overhead recovery charges in the first quarter of 2009. Our well operating agreements allow us, as operator, to charge labor to a well and to charge 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 labor and overhead charges increased by 19% between the first quarters of 2008 and 2009. Capitalized exploration and development costs also increased by approximately 18% between the comparable periods in 2008 and 2009, primarily due to additional personnel and increased compensation costs.

The net effect was a 42% increase in net G&A expense between the respective first quarters. On a per BOE basis, net G&A expense increased 20% in the first quarter of 2009 as compared to levels of those costs in the first quarter of 2008, as higher production offset a portion of the increase in gross costs.

Interest and Financing Expenses

	Three Months Ended March 31,	
Amounts in thousands, except per BOE data	2009	2008
Cash interest expense	$ 23,284	$ 11,800
Non-cash interest expense	1,286	407
Less: Capitalized interest	(12,373)	(7,266)
Interest expense	$ 12,197	$ 4,941
Interest and other income	$ 2,525	$ 1,287
Average net cash interest expense per BOE (1)	$ 2.15	$ 0.84
Average debt outstanding	$ 1,133,786	$ 661,809
Average interest rate (2)	8.2%	7.1%

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

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

Interest expense increased $7.3 million, or 147%, comparing the first quarters of 2008 and 2009. Interest expense has increased due to a higher average level of debt resulting from the acquisition of Hastings in early February 2009 and other borrowings to fund our development program, coupled with an increase in our average interest rate on our debt. Our average interest rate increased as a result of the two pipeline dropdown transactions with Genesis, 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.

The increase in our interest expense attributable to higher debt and interest costs was offset in part by a 70% increase in capitalized interest between the two periods. Our interest capitalization continues to increase because of our growing balance of unevaluated property expenditures, expenditures on our CO_2 pipeline projects and higher interest rates.

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Depletion, Depreciation and Amortization (DD&A)

Amounts in thousands, except per BOE data	Three Months Ended March 31, 2009	2008
Depletion and depreciation of oil and natural gas properties	$ 53,451	$ 44,190
Depletion and depreciation of CO_2 assets	4,542	3,022
Asset retirement obligations	827	762
Depreciation of other fixed assets	3,105	1,865
Total DD&A	$ 61,925	$ 49,839
DD&A per BOE:		
Oil and natural gas properties	$ 11.29	$ 11.00
CO_2 assets and other fixed assets	1.59	1.20
Total DD&A cost per BOE	$ 12.88	$ 12.20

Our depletion, depreciation and amortization rate for oil and natural gas properties on a per BOE basis decreased 5% from the fourth quarter 2008 DD&A rate of $11.92 per BOE, and increased 3% between the respective first quarters. The decrease in our oil and natural gas DD&A rate from the fourth quarter of 2008 is primarily due to the $226.0 million ($140.1 million net of taxes) full cost pool ceiling test write-down recognized at the end of 2008. The increase in the DD&A rate between the respective first quarters is due to increased production and capital spending, offset in part by the year-end 2008 write-down and to the addition of approximately 88.9 MMBOE of proved reserves during 2008.

We adjust our DD&A rate each quarter for significant changes in our estimates of oil and natural gas reserves and costs, and thus our DD&A rate could change significantly in the future. We did not record any additional tertiary oil reserves during the first quarter 2009. Assuming that we continue to see an increase in the level of tertiary production response at Cranfield Field during the second quarter of 2009, we would expect to recognize proved reserves associated with our CO_2 flood at Cranfield Field during the second quarter of 2009.

Our DD&A rate for our CO_2 and other fixed assets increased in the first quarter of 2009 as compared to the rate in the comparable quarter of 2008, primarily as a result of the Delta (Jackson Dome to Tinsley) and Heidelberg CO_2 pipelines being placed into service during 2008, and due to the expansion of our corporate office space, also during 2008. At March 31, 2009, we had $553.3 million of costs related to CO_2 pipelines under construction. These costs were not being depreciated at March 31, 2009. Depreciation of these pipelines will commence as each pipeline is placed into service.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. Although we did not have a write-down at March 31, 2009, we anticipate that if prices remain at these lower levels in subsequent periods, we may be required to record additional write-downs under the full cost pool ceiling test in the future. The amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices at the end of each period, the incremental proved reserves that may be added each period, and to additional capital spent.

DENBURY RESOURCES INC.
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Income Taxes

	Three Months Ended March 31,	
Amounts in thousands, except per BOE amounts and tax rates	2009	2008
Current income tax expense	$ 173	$ 21,236
Deferred income tax expense (benefit)	(10,851)	21,651
Total income tax expense (benefit)	$ (10,678)	$ 42,887
Average income tax expense (benefit) per BOE	$ (2.22)	$ 10.50
Effective tax rate	36.8%	37.0%

Our income tax provision was based on an estimated statutory rate of approximately 38% in both periods. Our effective tax rate has generally been lower than our estimated statutory rate due to the impact of certain items such as our domestic production activities deduction. In the first quarters of both years, the current income tax expense represents our anticipated alternative minimum cash taxes that we cannot offset with enhanced oil recovery credits. As of December 31, 2008, we had an estimated $44 million of enhanced oil recovery credits to carry forward that we can utilize to reduce our current income taxes during 2009 or future years.

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 March 31,	
Per BOE data	2009	2008
Oil and natural gas revenues	$ 34.97	$ 76.65
Gain (loss) on settlements of derivative contracts	17.85	(1.97)
Lease operating expenses	(15.59)	(16.15)
Production taxes and marketing expenses	(1.91)	(4.10)
Production netback	35.32	54.43
Non-tertiary CO_2 operating margin	0.39	0.42
General and administrative expenses	(4.71)	(3.92)
Net cash interest expense	(2.15)	(0.84)
Current income taxes and other	0.93	(4.39)
Changes in assets and liabilities relating to operations	(6.35)	4.78
Cash flow from operations	23.43	50.48
DD&A	(12.88)	(12.20)
Deferred income taxes	2.26	(5.30)
Non-cash commodity derivative adjustments	(22.13)	(9.48)
Changes in assets and liabilities and other non-cash items	5.51	(5.63)
Net income (loss)	$ (3.81)	$ 17.87

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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 $90 million of bank debt outstanding as of March 31, 2009, and $140 million outstanding as of May 8, 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 March 31, 2009, for estimated nonperformance risk in accordance with SFAS No. 157. This estimated nonperformance risk totaled approximately $10.6 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 March 31, 2009.

	Expected Maturity Dates				Carrying	Fair
Amounts in thousands	2011	2013	2015	2016	Value	Value
Variable rate debt:						
Bank debt (weighted average interest rate of 1.77% at March 31, 2009)	$90,000	$	$	$	$ 90,000	$ 79,436
Fixed rate debt:						
7.5% subordinated debt due 2013 (fixed rate of 7.5%)		225,000			224,223	203,625
7.5% subordinated debt due 2015 (fixed rate of 7.5%)			300,000		300,578	261,000
9.75% subordinated debt due 2016 (fixed rate of 9.75%)				420,000	390,363	405,300

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.

As a result of the current economic conditions and in order to protect our liquidity in the event that commodity prices continue to decline, during early October 2008, we purchased oil derivative contracts for 2009 with a floor price of $75 per Bbl and a ceiling price of $115 per Bbl for total consideration of $15.5 million. The collars cover 30,000 Bbls/d representing approximately 80% of our currently anticipated 2009 oil production. During March 2009, we entered into additional commodity derivative contracts to further protect our liquidity. The new commodity derivative contracts include crude oil swaps covering 25,000 Bbls/d during the first quarter of 2010 at a weighted average price of $51.85 per barrel, crude oil collars covering 25,000 Bbls/d during the second quarter of 2010 with a floor price of $50.00 per barrel and a weighted average ceiling price of $74.60 per barrel, natural gas swaps for calendar year 2010 covering 55,000 MMBtu/d at a weighted average price of $5.66 per MMBtu and natural gas swaps for calendar year 2011 covering 40,000 MMBtu/d at a weighted average price of $6.21 per MMBtu.

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. We have included an estimate of nonperformance risk in the fair value measurement of our oil derivative contracts as required by SFAS No. 157. In assessing the nonperformance risk of the counterparties to these contracts, we have measured the risk by using credit default swaps as we believe this data is the most responsive to current market events. If a counter-party did not have credit default swaps associated with that specific entity, we utilized industry credit default swaps to estimate the fair value of this risk associated with that entity. At March 31, 2009, the fair value of our oil and natural gas derivative contracts was reduced by $1.7 million for the estimated nonperformance risk of our counterparties.

For accounting purposes, we do not apply hedge accounting for 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 March 31, 2009, our derivative contracts were recorded at their fair value, which was a net asset of approximately $143.4 million, a decrease of $106.3 million from the $249.7 million fair value asset recorded as of December 31, 2008. This change is primarily related to the expiration of our oil derivative contracts during the first quarter of 2009, and to the oil and natural gas futures prices as of March 31, 2009 in relation to the new commodity derivative contracts for 2010 and 2011.

Commodity Derivative Sensitivity Analysis

Based on NYMEX crude oil and natural gas futures prices as of March 31, 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:

In thousands	Crude Oil Derivative Contracts Receipt/ (Payment)	Natural Gas Derivative Contracts Receipt/ (Payment)
Based on:		
NYMEX futures prices as of March 31, 2009	$149,916	($12,086)
10% increase in prices	91,359	(33,705)
10% decrease in prices	208,455	9,546

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

SFAS No. 157, Fair Value Measurements 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 1 of 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,

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assessment of impairment of goodwill, and
recorded value of derivative instruments.

Acquisitions

Under the acquisition method of accounting for business combinations in SFAS No. 141(R), 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. SFAS No. 141(R) 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. SFAS No. 157 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). Further, SFAS No. 157 emphasizes that a fair value measurement should be 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.

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

Goodwill must be tested for impairment at least annually, 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,

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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, 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 co uncertainty of future events or outcomes. 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 or its availability, 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 quarterly 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.

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

We maintain disclosure controls and procedures and 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. 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.

There have been no significant changes in internal controls over financial reporting during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, Denbury s internal controls 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.

Item 1A. Risk Factors

Information with respect to risk factors has been incorporated by reference from Item 1.A. 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.

DENBURY RESOURCES INC.

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 Program
January 1 through 31, 2009	40,091	$12.23		
February 1 through 28, 2009	468	13.75		
March 1 through 31, 2009	317	14.81		
Total	40,876	12.27		

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.

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:

10(a)* Amendment to Sixth Amended and Restated Credit Agreement dated as of May 4, 2009.

10(b)* 2009 form of restricted stock award to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

10(c)* 2009 form of restricted stock award without change of control vesting to certain officers that cliff vests on March 31, 2012 pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

10(d)* 2009 form of performance share awards to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

10(e)* 2009 form of performance share awards without change of control vesting to certain officers pursuant to 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

10(f)* 2009 form of stock appreciation rights to certain officers that cliff vests on March 31, 2012 pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

10(g)* 2009 form of stock appreciation rights without change of control vesting to certain officers pursuant to the 2004 Omnibus Stock and Incentive Plan for Denbury Resources Inc.

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.

* Filed herewith.

DENBURY RESOURCES INC.

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/ Phil Rykhoek
Phil Rykhoek
Sr. Vice President and Chief Financial Officer

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

Date: May 11, 2009