DENBURY RESOURCES INC
Form 10-Q
November 07, 2008

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

(Mark One)

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2008

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

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

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

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

Class	Outstanding at October 31, 2008
Common Stock, $.001 par value	247,042,565

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

	September 30, 2008	December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	$ 175,310	$ 60,107
Accrued production receivable	146,904	136,284
Trade and other receivables, net of allowance of $362 and $369	70,017	28,977
Deferred tax asset	30,504	12,708
Derivative assets	1,673	2,283
Total current assets	424,408	240,359
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,193,577	2,682,932
Unevaluated	244,622	366,518
CO_2 properties and equipment	673,086	436,591
Other	66,304	50,116
Less accumulated depletion and depreciation	(1,302,961)	(1,143,282)
Net property and equipment	2,874,628	2,392,875
Deposits on property under option or contract	49,193	49,097
Other assets	120,303	88,746
Total assets	$ 3,468,532	$ 2,771,077
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 180,981	$ 147,580
Oil and gas production payable	108,535	84,150
Derivative liabilities	7,881	28,096
Deferred revenue Genesis	4,070	4,070
Current maturities of long-term debt	3,932	737
Total current liabilities	305,399	264,633
Long-term liabilities		
Long-term debt Genesis	251,379	4,544
Long-term debt	525,612	675,786
Asset retirement obligations	42,943	38,954

Deferred revenue Genesis	21,041	24,424
Deferred tax liability	521,636	347,370
Other	12,537	10,988
Total long-term liabilities	1,375,148	1,102,066
Stockholders equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding		
Common stock, $.001 par value, 600,000,000 shares authorized; 247,581,299 and 245,386,951 shares issued at September 30, 2008 and December 31, 2007, respectively	248	245
Paid-in capital in excess of par	702,163	662,698
Retained earnings	1,095,782	751,179
Accumulated other comprehensive loss	(645)	(1,591)
Treasury stock, at cost, 624,715 and 637,795 shares at September 30, 2008 and December 31, 2007, respectively	(9,563)	(8,153)
Total stockholders equity	1,787,985	1,404,378
Total liabilities and stockholders equity	$ 3,468,532	$ 2,771,077

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues and other income				
Oil, natural gas and related product sales	$ 402,108	$ 248,213	$ 1,128,548	$ 634,826
CO_2 sales and transportation fees	3,471	3,594	9,705	10,079
Interest income and other	4,675	1,702	7,321	5,269
Total revenues	410,254	253,509	1,145,574	650,174
Expenses				
Lease operating expenses	85,308	59,323	228,134	167,087
Production taxes and marketing expenses	17,104	10,956	50,978	28,819
Transportation expense Genesis	2,231	1,720	5,623	4,447
CO_2 operating expenses	1,240	1,304	2,836	3,211
General and administrative	15,005	11,541	45,821	34,669
Interest, net of amounts capitalized of $6,713, $5,431, $19,524 and $13,785, respectively	10,906	8,628	23,988	23,059
Depletion, depreciation and amortization	56,324	52,797	160,896	140,059
Commodity derivative expense (income)	(62,007)	(3,973)	43,591	7,885
Abandoned acquisition cost	30,426		30,426	
Total expenses	156,537	142,296	592,293	409,236
Income before income taxes	253,717	111,213	553,281	240,938
Income tax provision				
Current income taxes	12,689	5,197	44,769	14,158
Deferred income taxes	83,480	38,028	163,909	79,609
Net income	$ 157,548	$ 67,988	$ 344,603	$ 147,171
Net income per common share basic	$ 0.64	$ 0.28	$ 1.41	$ 0.61
Net income per common share diluted	$ 0.63	$ 0.27	$ 1.36	$ 0.59
Weighted average common shares outstanding				
Basic	244,426	240,867	243,604	239,489
Diluted	251,831	250,449	252,708	250,809

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Cash flow from operating activities:				
Net income	$ 157,548	$ 67,988	$ 344,603	$ 147,171
Adjustments needed to reconcile to net cash flow provided by operations:				
Depreciation, depletion and amortization	56,324	52,797	160,896	140,059
Deferred income taxes	83,480	38,028	163,909	79,609
Deferred revenue Genesis	(1,201)	(1,230)	(3,383)	(3,252)
Stock based compensation	3,594	2,820	10,979	8,270
Non-cash fair value derivative adjustments	(86,051)	5,496	(17,048)	27,217
Amortization of debt issue costs and other	(2,525)	877	(2,921)	2,422
Changes in assets and liabilities related to operations:				
Accrued production receivable	33,739	(8,325)	(10,620)	(30,395)
Trade and other receivables	549	(11,351)	(46,330)	(23,136)
Other assets	(81)	(259)	188	(405)
Accounts payable and accrued liabilities	19,511	16,864	9,069	1,363
Oil and gas production payable	(2,680)	4,077	24,385	13,288
Other liabilities	235	1,432	(956)	2,600
Net cash provided by operating activities	262,442	169,214	632,771	364,811
Cash flow used for investing activities:				
Oil and natural gas capital expenditures	(136,868)	(170,812)	(435,871)	(470,121)
Acquisitions of oil and gas properties	(1,905)	1,959	(4,262)	(44,701)
Change in accrual for capital expenditures	30,272	4,908	24,273	(3,861)
Acquisitions of CO_2 assets and CO_2 capital expenditures	(127,583)	(33,981)	(236,433)	(102,408)
Distributions from Genesis	2,128		4,853	
Investment in Genesis		(28,563)	(515)	(28,563)
Net purchases of other assets	(3,772)	(3,796)	(20,703)	(6,530)
Net proceeds from sales of oil and gas property and equipment	(81)	127	48,948	5,967
Other	2,204	(887)	2,033	(1,847)
Net cash used for investing activities	(235,605)	(231,045)	(617,677)	(652,064)
Cash flow from financing activities:				
Bank repayments			(222,000)	(140,000)
Bank borrowings		60,000	72,000	236,000
Income tax benefit from equity awards	3,219	7,504	17,362	16,344
Pipeline financing Genesis	63		225,311	
Issuance of subordinated debt				150,750

Issuance of common stock	1,977	4,371	11,687	15,058
Other	(3,795)	(3,207)	(4,251)	(5,358)
Net cash provided by financing activities	1,464	68,668	100,109	272,794
Net increase (decrease) in cash and cash equivalents	28,301	6,837	115,203	(14,459)
Cash and cash equivalents at beginning of period	147,009	32,577	60,107	53,873
Cash and cash equivalents at end of period	$ 175,310	$ 39,414	$ 175,310	$ 39,414
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest	$ 6,962	$ 2,980	$ 29,959	$ 24,329
Cash paid during the period for income taxes	11,720	1,431	70,349	8,801
Interest capitalized	6,713	5,431	19,524	13,785

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 157,548	$ 67,988	$ 344,603	$ 147,171
Other comprehensive income, net of income tax:				
Change in fair value of derivative contracts designated as a hedge, net of tax of $-, $458, ($49) and $421, respectively		(716)	12	(659)
Interest rate lock derivative contracts reclassified to income, net of taxes of $11 and $573, respectively	16		934	
Comprehensive income	$ 157,564	$ 67,272	$ 345,549	$ 146,512

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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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, 2007. Any capitalized terms used but not defined in these Notes to Unaudited Condensed Consolidated Financial Statements have the same meaning given to them in the Form 10-K.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. In management s opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments (of a normal recurring nature) necessary to present fairly the consolidated financial position of Denbury as of September 30, 2008 and the consolidated results of its operations and cash flows for the three and nine month periods ended September 30, 2008 and 2007. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

Stock Split

On November 19, 2007, stockholders of Denbury Resources Inc. approved an amendment to our Restated Certificate of Incorporation to increase the number of shares of our authorized common stock from 250,000,000 shares to 600,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on December 5, 2007, received one additional share of Denbury common stock for each share of common stock held at that time. Information pertaining to shares and earnings per share has been retroactively adjusted in the accompanying financial statements and related notes thereto to reflect the stock split.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income by the weighted average number of shares of common stock outstanding during the period. Diluted net income per common share is calculated in the same manner but also considers the impact on net income and common shares for the potential dilution from stock options, stock appreciation rights (SARs), non-vested restricted stock and any other convertible securities outstanding. For the three and nine month periods ended September 30, 2008 and 2007, there were no adjustments to net income for purposes of calculating diluted net income per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income per common share calculations for the three and nine month periods ended September 30, 2008 and 2007.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Share amounts in thousands	2008	2007	2008	2007
Weighted average common shares basic	244,426	240,867	243,604	239,489
Potentially dilutive securities:				
Stock options and SARs	6,035	8,021	7,439	9,877
Restricted stock	1,370	1,561	1,665	1,443
Weighted average common shares diluted	251,831	250,449	252,708	250,809

The weighted average common shares basic amount excludes 2,242,699 shares at September 30, 2008 and 2,702,740 shares at September 30, 2007, of non-vested restricted stock that is subject to future vesting over time. As

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Notes to Unaudited Condensed Consolidated Financial Statements

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.

For the three months ended September 30, 2008 and 2007, stock options and SARs to purchase approximately 1,028,000 and 16,000 shares of common stock, and for the nine months ended September 30, 2008 and 2007, stock options and SARs to purchase approximately 1,011,000 and 173,000 shares of common stock, respectively, were outstanding but excluded from the diluted net income per common share calculations, as the exercise prices of the options exceeded the average market price of the Company s common stock during these periods and would be anti-dilutive to the calculations.

Accounting for Tertiary Injection Costs

Prior to January 1, 2008, we expensed all costs associated with injecting CO_2 used in our tertiary recovery operations, even though some of these costs were incurred prior to any tertiary related oil production. Commencing January 1, 2008, we began capitalizing, as a development cost, injection costs in tertiary fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e. a production response). These capitalized development costs are included in our unevaluated property costs until we record proved tertiary reserves in that field associated with those costs. After we see a production response to the CO_2 injections (i.e. the production stage), injection costs are expensed as incurred, and any previously deferred development costs included in unevaluated properties become subject to depletion upon recognition of proved tertiary reserves. Since we are continuing to initiate new tertiary floods, this means that we are now capitalizing certain costs that we historically expensed. Had we continued with the prior accounting methodology of expensing all tertiary injectant costs, we would have expensed an additional $2.9 million during the first quarter of 2008, $1.4 million during the second quarter of 2008, and $1.1 million during the third quarter of 2008. During the first nine months of 2007, the impact of this accounting methodology was not material, as only $1.5 million would have been capitalized under the new accounting procedure.

Recently Adopted Accounting Pronouncement

Fair Value Measurements

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with United States generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, but provides guidance on how to measure fair value by providing a fair value hierarchy used to classify the source of the information. On February 12, 2008, the FASB issued FSP SFAS No. 157-2 which delays 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). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. This deferral of SFAS No. 157 applies to our asset retirement obligation (ARO), which uses fair value measures at the date incurred to determine our liability. However, we do not expect the adoption of SFAS No. 157 to significantly change the methodology we use to estimate the initial fair value of our ARO, because the guidance in SFAS No. 157 is consistent with the fair value guidance in SFAS No. 143, Accounting for Asset Retirement Obligations which we apply to determine our ARO.

In October 2008, the FASB issued FSP FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active. FSP FAS 157-3 clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 is effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application should be accounted for as a change in accounting estimate following the guidance in FASB Statement No. 154, Accounting Changes and Error Corrections. FSP FAS 157-3 is effective for the

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Notes to Unaudited Condensed Consolidated Financial Statements

financial statements included in the Company s quarterly report for the period ended September 30, 2008, but had no impact on the Company s Unaudited Condensed Consolidated Financial Statements.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

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

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

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. During 2008 we had no level 3 recurring 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 September 30, 2008.

	Fair Value Measurements at September 30, 2008 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	$	$ 1,673	$	$ 1,673
Liabilities:				
Oil and natural gas derivative contracts		(7,881)		(7,881)
Total	$	$ (6,208)	$	$ (6,208)

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

Recently Issued Accounting Pronouncement

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

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Notes to Unaudited Condensed Consolidated Financial Statements

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. SFAS No. 161 is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our disclosures about derivatives.

Note 2. Oil and Natural Gas Properties Acquisitions and Divestitures

Sale of Louisiana Natural Gas Assets

In October 2007, we entered into an agreement to sell our Louisiana natural gas assets to a privately held company for approximately $180 million (before closing adjustments), plus we retained a net profits interest in one well. In late December 2007, we closed on approximately 70% of that sale with net proceeds of approximately $108.6 million (including estimated final purchase price adjustments). We closed on the remaining portion of the sale in February 2008 and received net proceeds of approximately $48.9 million. The agreement has an effective date of August 1, 2007, and consequently operating net revenue after August 1, 2007, net of capital expenditures, along with any other minor closing items were adjustments to the purchase price. The potential net profits interest relates to a well in the South Chauvin field and is only earned if operating income from that well exceeds certain levels. The operating results of these sold properties are included in our financial statements through the applicable closing dates of the sold properties. We did not record any gain or loss on the sale in accordance with the full cost method of accounting.

Cancellation of Conroe Field Acquisition

In August 2008, we entered into an agreement with a privately owned company to purchase a 91.4% interest in Conroe Field, a significant potential tertiary flood north of Houston, Texas, for $600 million, plus additional potential consideration if oil prices were to exceed $121 per barrel during the next three years. Closing was provided for in early October 2008. Based on current capital market conditions, and a desire to refrain from increasing our leverage in the current environment, we cancelled the contract to purchase the Conroe Field, forfeiting a $30 million non-refundable deposit. The $30 million deposit plus miscellaneous acquisition costs of $0.4 million are included in Abandoned acquisition costs in our Unaudited Condensed Consolidated Statement of Operations.

Pending Hastings Acquisition

In September 2008, we exercised our option with a subsidiary of Venoco, Inc. (Venoco) to purchase the Hastings Field located near Houston, Texas, a potential tertiary oil field to be supplied by the Green Pipeline which is about to commence construction. The option agreement stipulates that the purchase price is to be determined by mutual agreement between the two companies, or failing agreement by December 1, 2008, by following a prescribed contractual formula based upon the present discounted value (PV10 Value) of the field s proved reserves as determined by the independent engineering firm DeGoyler MacNaughton, using year-end 2008 strip prices. The acquisition will be effective January 1, 2009 and is expected to close early February 2009. Venoco agreed to extend the deadlines for capital expenditures, commencement of CO_2 injections and certain other contractual requirements by one year in consideration of us exercising the option in 2008 rather than 2009. Since this acquisition will likely be based upon year-end 2008 prices, the purchase price has not yet been determined. Based on commodity prices as of the end of October 2008, the estimated purchase price would be between $150 million and $250 million, assuming that Venoco does not exercise their option to take a volumetric production payment in lieu of a cash payment.

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 obligation 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

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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 nine months ended September 30, 2008.

Amounts in thousands	Nine Months Ended September 30, 2008
Balance, beginning of period	$ 41,258
Liabilities incurred and assumed during period	1,261
Revisions in estimated retirement obligations	1,483
Liabilities settled during period	(1,928)
Accretion expense	2,286
Sales of properties	(352)
Balance, end of period	$ 44,008

At September 30, 2008, $1.1 million of our asset retirement obligation was classified in Accounts payable and accrued liabilities under current liabilities in our Unaudited Condensed Consolidated Balance Sheets. Liabilities incurred during the nine month period ended September 30, 2008 are primarily for oil, natural gas and CO_2 wells drilled during the period. We hold cash and liquid investments in escrow accounts that are legally restricted for certain of our asset retirement obligations. The balances of these escrow accounts was $7.3 million at September 30, 2008 and $9.5 million at December 31, 2007 and are included in Other assets in our Unaudited Condensed Consolidated Balance Sheets.

Note 4. Long-Term Debt

Amounts in thousands	September 30, 2008	December 31, 2007
7.5% Senior Subordinated Notes due 2015	$ 300,000	$ 300,000
Premium on Senior Subordinated Notes due 2015	621	685
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(874)	(1,020)
NEJD financing Genesis	174,317	
Free State financing Genesis	75,994	
Senior bank loan		150,000
Capital lease obligations Genesis	4,724	5,238
Capital lease obligations	1,142	1,164
Total	780,924	681,067
Less current obligations	3,932	737
Long-term debt and capital lease obligations	$ 776,992	$ 680,330

NEJD Financing and Free State Financing

On May 30, 2008, we closed on two transactions with Genesis Energy, L.P. (Genesis) involving two of our pipelines. The two transactions have been recorded as financing leases. See Note 5. Related Party Transactions Genesis NEJD Pipeline and Free State Pipeline Transactions.

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Notes to Unaudited Condensed Consolidated Financial Statements

Senior Bank Loan

Effective April 1, 2008, we amended our Sixth Amended and Restated Credit Agreement, the instrument governing our senior bank loan, which increased our borrowing base from $500 million to $1.0 billion. In early October 2008, we further amended our bank credit facility which increased the banks commitment amount from $350 million to $750 million and maintained the borrowing base at $1.0 billion. This most recent bank amendment also (i) allowed us to divest of our Barnett Shale properties, (ii) allowed us to do a tax free like-kind exchange of the Barnett Shale properties for Conroe, Hastings and other fields, (iii) allowed for additional permitted indebtedness of up to $600 million in the form of subordinated or convertible debt, and (iv) modified the commitment fees and pricing grid for the loan, raising the pricing grid by 25 basis points.

With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our mortgaged assets, as confirmed by the banks, while the commitment amount is the amount the banks have committed to fund pursuant to the terms of the credit agreement. The banks have the option to participate in any borrowing request by us in excess of the commitment amount ($750 million), up to the borrowing base limit ($1.0 billion), although the banks are not obligated to fund any amount in excess of the commitment amount. At September 30, 2008, we had no debt outstanding on our bank credit line.

5. Related Party Transactions Genesis

Interest in and Transactions with Genesis

Denbury s subsidiary, Genesis Energy, Inc. is the general partner of, and together with Denbury s other subsidiaries, owns an aggregate 12% interest in Genesis, a publicly traded master limited partnership. Genesis business is focused on the mid stream segment of the oil and 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 $4.9 million and $0.9 million during the nine months ended September 30, 2008 and 2007, respectively. We also received $0.1 million in each of these periods 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, Inc.

NEJD Pipeline and Free State Pipeline Transactions

On May 30, 2008, we closed two transactions with Genesis involving our Northeast Jackson Dome (NEJD) pipeline system and Free State CO_2 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 received from Genesis $225 million in cash and $25 million in Genesis common limited partnership units. We used the proceeds to repay our outstanding borrowing on our bank credit facility and the balance we have temporarily invested in cash. We have recorded both of these transactions as financing leases. At September 30, 2008, we had $174.3 million for the NEJD financing and $76.0 million for the Free State financing recorded as debt on our Unaudited Condensed Consolidated Balance Sheet (see Note 4. Long-Term Debt).

The NEJD pipeline system is a 183-mile, 20 pipeline extending from the Jackson Dome, near Jackson, Mississippi, to near Donaldsonville, Louisiana, and is currently being used by us to transport CO_2 for our tertiary operations in southwest Mississippi. We have the rights to exclusive use of the NEJD pipeline system, we will be responsible for all operations and maintenance on the system, and we will bear and assume all obligations and liabilities with respect to the pipeline. The NEJD financing lease requires us to make quarterly base rent payments beginning August 30, 2008. These quarterly rent payments are fixed at $5.2 million per quarter or approximately $20.7 million per year (prorated for 2008) during the 20-year term, at an interest rate of approximately 10.25% per annum. At the end of the term, Genesis will release its secured interest in the line to us for $1.00. We have the option or obligation upon the occurrence of certain events specified in the financing lease, and may have the obligation if we default, to prepay our financing lease

DENBURY RESOURCES INC.

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obligations. 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 Free State pipeline is an 86-mile, 20 pipeline that extends from our CO_2 source fields at the Jackson Dome, near Jackson, Mississippi, to our oil fields in east Mississippi. Under the terms of the transportation agreement, Genesis is responsible for owning, operating, maintaining and making improvements to the pipeline. We have exclusive use of the pipeline and are required to use the pipeline to supply CO_2 to certain of our tertiary operations in east Mississippi. The Free State transportation agreement requires us to make monthly payments of $0.1 million plus a through-put fee based on average daily volumes per month with no minimum volumes required. Based on our forecasted through-put, we currently project that we will initially pay Genesis approximately $9.3 million per annum (prorated for 2008). Approximately $1.5 million (increasing at 1% per year) of the annual payments will be expensed as operating costs, with the remainder recognized as principal and interest expense. The implicit rate on the financing is approximately 13.2% per annum.

Oil Sales and Transportation Services

We utilize Genesis trucking services and common carrier pipeline in Mississippi to transport certain of our crude oil production to sales points where it is sold to third party purchasers. In the first nine months of 2008 and 2007, we expensed $5.6 million and $4.4 million, respectively, for these transportation services.

Transportation Leases

In late 2004 and early 2005, we entered into 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 September 30, 2008, and December 31, 2007, we had $4.7 million and $5.2 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 September 30, 2008 and December 31, 2007, $25.1 million and $28.5 million, respectively, were recorded as deferred revenue of which $4.1 million was included in current liabilities at both September 30, 2008 and December 31, 2007. We recognized deferred revenue for deliveries under these volumetric production payments of $1.2 million during each of the three month periods ended September 30, 2008 and 2007 and $3.4 million and $3.3 million for the nine month periods ended September 30, 2008 and 2007, respectively. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.18 per Mcf of CO_2. For these services, we recognized revenues of $1.5 million for each of the three month periods ended September 30, 2008 and 2007 and $4.1 million and $3.8 million for the nine months ended September 30, 2008 and 2007, 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 gas derivative contracts and therefore the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts are shown under Commodity derivative expense (income) in our Unaudited Condensed Consolidated Statements of Operations.

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Notes to Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands	2008	2007	2008	2007
Receipt (payment) on settlements of derivative contracts Oil	$ (11,186)	$ (3,018)	$ (30,709)	$ (3,999)
Receipt (payment) of settlements of derivative contracts Gas	(12,886)	12,432	(30,005)	23,383
Fair value adjustments to derivative contracts income (expense)	86,079	(5,441)	17,123	(27,269)
Commodity derivative income (expense)	$ 62,007	$ 3,973	$ (43,591)	$ (7,885)

Oil and Natural Gas Commodity Derivative Contracts at September 30, 2008:

Crude Oil Contracts at September 30, 2008:

Type of Contract and Period	Counterparty	NYMEX Contract Prices Per Bbl: Bbls/d	NYMEX Contract Prices Per Bbl: Swap Price	Estimated Fair Value Liability at September 30, 2008 (In Thousands)
Swap Contracts				
Oct. 2008 - Dec. 2008	Comerica Bank	2,000	$57.34	$ (7,881)

Natural Gas Contracts at September 30, 2008:

Type of Contract and Period	Counterparty	NYMEX Contract Prices Per MMBtu: MMBtu/d	NYMEX Contract Prices Per MMBtu: Swap Price	Estimated Fair Value Asset at September 30, 2008 (In Thousands)
Swap Contracts				
Oct. 2008 - Nov. 2008	JPMorgan Chase Bank	20,000	$ 7.89	$ 529
Oct. 2008 - Nov. 2008	Wells Fargo Bank	20,000	7.91	554
Oct. 2008 - Nov. 2008	Bank of America	20,000	7.94	590

During September 2008, in anticipation of the possible sale of our Barnett Shale properties, we settled the December 2008 portion of each of our existing natural gas derivative contracts for a net receipt of $61,000. This amount is included in Commodity derivative expense (income) in our Unaudited Condensed Consolidated Statement of Operations. At September 30, 2008, our oil and natural gas derivative contracts were recorded at their fair value, which was a net liability of $6.2 million.

In October 2008, we purchased oil derivative contracts for calendar year 2009 covering 30,000 Bbls/d. These contracts have a floor price of $75 / Bbl and a ceiling price of $115 / Bbl, and were purchased for $15.5 million. These 2009 contracts were entered into with the following counterparties: JPMorgan Chase Bank (10,000 Bbls/d), Wells Fargo Bank (7,500 Bbls/d), Keybank (5,000 Bbls/d), Fortis Energy Marketing and Trading GP (5,000 Bbls/d) and Comerica Bank (2,500 Bbls/d).

Interest Rate Lock Derivative Contracts

In January 2007, we entered into interest rate lock contracts to remove our exposure to possible interest rate fluctuations related to our commitment to the sale-leaseback financing of certain equipment for CO_2 recycling facilities at our tertiary oil fields. We are applying hedge accounting to these contracts as provided under SFAS No. 133. For these instruments designated as interest rate hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Amounts representing hedge

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

ineffectiveness are recorded in earnings. Hedge effectiveness is assessed quarterly based on the total change in the contract s fair value.

On June 30, 2008, we settled our remaining interest rate lock contracts for a payment due to the counterparty of approximately $1.6 million. During the second quarter of 2008, we determined that we would not complete the anticipated sale-leaseback transactions which were designated as the forecasted hedged transactions for several of the interest rate lock contracts. As a result, we reclassified the $1.4 million in fair market value changes for these contracts that was in Accumulated other comprehensive loss to expense during the second quarter of 2008. We have $0.6 million (net of taxes of $0.4 million) in Accumulated other comprehensive loss in our September 30, 2008 Unaudited Condensed Consolidated Balance Sheet. We recognized ineffectiveness totaling $0.1 million as expense in our Unaudited Condensed Consolidated Statement of Operations for the nine months ended September 30, 2008.

Note 7. Income Taxes

The Company recently obtained approval from the Internal Revenue Service (IRS) to change its method of tax accounting for certain assets used in its tertiary oilfield recovery operations. Previously, the Company capitalized and depreciated these costs, but now it can deduct these costs once the assets are placed into service. As a result, the Company expects to receive tax refunds of approximately $10.6 million for tax years through 2007, and in the third quarter of 2008 has reduced its current income tax expense to adjust for the impact of this change. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it will reduce the amount of cash taxes the Company expects to pay over the next several years.

Note 8. Condensed Consolidating Financial Information

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

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Balance Sheets

	September 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 472,081	$ 427,482	$ 18,246	$ (493,401)	$ 424,408
Property and equipment		2,860,335	14,293		2,874,628
Investment in subsidiaries (equity method)	1,307,870		1,251,272	(2,559,142)	
Other assets	319,860	110,951	55,796	(317,111)	169,496
Total assets	$ 2,099,811	$ 3,398,768	$ 1,339,607	$ (3,369,654)	$ 3,468,532
Liabilities and Stockholders Equity					
Current liabilities	$ 11,205	$ 756,019	$ 31,576	$ (493,401)	$ 305,399
Long-term liabilities	300,621	1,391,477	161	(317,111)	1,375,148
Stockholders equity	1,787,985	1,251,272	1,307,870	(2,559,142)	1,787,985
Total liabilities and stockholders equity	$ 2,099,811	$ 3,398,768	$ 1,339,607	$ (3,369,654)	$ 3,468,532

	December 31, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Assets					
Current assets	$ 430,518	$ 237,273	$ 7,263	$ (434,695)	$ 240,359
Property and equipment		2,392,865	10		2,392,875
Investment in subsidiaries (equity method)	961,990		905,796	(1,867,786)	
Other assets	312,556	78,230	57,226	(310,169)	137,843
Total assets	$ 1,705,064	$ 2,708,368	$ 970,295	$ (2,612,650)	$ 2,771,077

Liabilities and Stockholders Equity					
Current liabilities	$	$ 691,062	$ 8,266	$ (434,695)	$ 264,633
Long-term liabilities	300,686	1,111,510	39	(310,169)	1,102,066
Stockholders equity	1,404,378	905,796	961,990	(1,867,786)	1,404,378
Total liabilities and stockholders equity	$ 1,705,064	$ 2,708,368	$ 970,295	$ (2,612,650)	$ 2,771,077

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,625	$ 407,823	$ 2,431	$ (5,625)	$ 410,254
Expenses	5,745	155,578	839	(5,625)	156,537
Income (loss) before the following:	(120)	252,245	1,592		253,717
Equity in net earnings of subsidiaries	157,658		156,791	(314,449)	
Income before income taxes	157,538	252,245	158,383	(314,449)	253,717
Income tax provision (benefit)	(10)	95,454	725		96,169
Net income	$ 157,548	$ 156,791	$ 157,658	$ (314,449)	$ 157,548

	Three Months Ended September 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,625	$ 253,316	$ 193	$ (5,625)	$ 253,509
Expenses	5,750	141,539	632	(5,625)	142,296
Income (loss) before the following:	(125)	111,777	(439)		111,213
Equity in net earnings of subsidiaries	68,505		68,996	(137,501)	
Income before income taxes	68,380	111,777	68,557	(137,501)	111,213
Income tax provision	392	42,781	52		43,225
Net income	$ 67,988	$ 68,996	$ 68,505	$ (137,501)	$ 67,988

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations (continued)

	Nine Months Ended September 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 16,875	$ 1,142,285	$ 3,289	$ (16,875)	$ 1,145,574
Expenses	17,236	589,461	2,471	(16,875)	592,293
Income (loss) before the following:	(361)	552,824	818		553,281
Equity in net earnings of subsidiaries	344,933		345,045	(689,978)	
Income before income taxes	344,572	552,824	345,863	(689,978)	553,281
Income tax provision (benefit)	(31)	207,779	930		208,678
Net income	$ 344,603	$ 345,045	$ 344,933	$ (689,978)	$ 344,603

	Nine Months Ended September 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 13,969	$ 649,927	$ 247	$ (13,969)	$ 650,174
Expenses	14,300	406,985	1,920	(13,969)	409,236
Income (loss) before the following:	(331)	242,942	(1,673)		240,938
Equity in net earnings of subsidiaries	147,884		149,566	(297,450)	
Income before income taxes	147,553	242,942	147,893	(297,450)	240,938
Income tax provision	382	93,376	9		93,767
Net income	$ 147,171	$ 149,566	$ 147,884	$ (297,450)	$ 147,171

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flows

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

	Nine Months Ended September 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ 33	$ 364,108	$ 670	$	$ 364,811
Cash flow from investing activities	(177,291)	(652,064)		177,291	(652,064)
Cash flow from financing activities	177,291	272,794		(177,291)	272,794
Net increase (decrease) in cash	33	(15,162)	670		(14,459)
Cash, beginning of period	1	52,225	1,647		53,873
Cash, end of period	$ 34	$ 37,063	$ 2,317	$	$ 39,414

Note 9. Subsequent Events

In October 2008, we amended our bank credit facility which, among other things, increased the commitment amount on our bank credit facility from $350 million to $750 million. See Note 4. Long Term Debt for a complete description of this amendment.

In October 2008, we purchased oil derivative contracts for calendar year 2009. See Note 6. Derivative Instruments and Hedging Activities for further information about these contracts.

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DENBURY RESOURCES INC.

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

You should read the following in conjunction with our financial statements contained herein and our Form 10-K for the year ended December 31, 2007, 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.

We are a growing independent oil and gas company engaged in acquisition, development and exploration activities in the U.S. Gulf Coast region. We are the largest oil and natural gas producer in Mississippi, own the largest carbon dioxide (CO_2) reserves east of the Mississippi River used for tertiary oil recovery, and hold significant operating acreage in the Barnett Shale play near Fort Worth, Texas, onshore Louisiana and Alabama, 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, including secondary and 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 Cleburne, Texas.

Overview

Operating Results. During the third quarter of 2008 our production averaged 45,913 BOE/d, a 13% increase over third quarter 2007 production after adjusting for the sale of our Louisiana natural gas properties in December 2007 and February 2008, and approximately the same as second quarter 2008 production levels. The third quarter 2008 production was negatively impacted by two hurricanes, reducing our targeted third quarter 2008 production by approximately 1,250 BOE/d. In spite of the hurricanes, our tertiary oil production increased to 19,784 Bbls/d, a 1,123 Bbls/d sequential increase over its level in the second quarter of 2008, but production from our second largest production area, the Barnett Shale, decreased sequentially to 12,339 BOE/d, a 1,095 BOE/d decrease, primarily as a result of the hurricanes. (See Results of Operations Operating Results Production for more information about the impact of the two hurricanes).

Commodity prices began to decline during the third quarter of 2008, down only 3% on an average per BOE quarterly basis from second quarter of 2008 levels, although commodity prices were significantly lower by quarter-end. However, average prices for the third quarter were still 61% higher on a per BOE basis than prices received during the third quarter of 2007. During the period of rising commodity prices in the first six months of 2008, we recognized non-cash fair value losses on our oil and natural gas derivative contracts of $68.9 million, but more than reversed that loss when prices declined in the third quarter of 2008, during which we recognized non-cash fair value income of $86.1 million on those same contracts. During the third quarter of 2008, we made cash payments of $24.1 million on our derivative contracts, in addition to the $36.6 million paid during the first six months of 2008. This compares to a $27.3 million non-cash fair value charge on our derivative contracts in the nine month period of 2007 and net cash receipts of $19.4 million on those contracts during that same period. On a comparative quarterly basis, during the third quarter of 2007, we recognized non-cash fair value losses of $5.4 million and had net cash receipts of $9.4 million.

Virtually all of our expenses increased on both an absolute and per BOE basis during the third quarter of 2008, due to (i) higher overall industry costs, (ii) a higher percentage of operations related to tertiary operations (which have higher operating costs per BOE), and (iii) higher compensation expense resulting from additional employees and increased salaries, which we consider necessary in order to remain competitive in the industry. In addition, the sale of our Louisiana natural gas properties in late 2007 and early 2008, which had lower operating costs per BOE, increased our operating cost per BOE by over $1.00, based on 2007 average costs. Interest expense increased in the third quarter of 2008 primarily as a result of the incremental interest on the financing leases relating to the CO_2 pipeline transactions with Genesis in May 2008 (see Genesis Transactions below). During the third quarter of 2008 we also recognized a $30.4 million charge primarily relating to a deposit we forfeited when we decided not to close the Conroe Field acquisition (see Capital Resources and Liquidity below). The net result was net income of $157.5 million during the third quarter of 2008, a company quarterly record, as compared to $68.0 million of net income during the third quarter of 2007. On a nine month basis, net income was $344.6 million during the first nine months of 2008, as compared to net income of $147.2 million during the first nine months of 2007, as higher commodity prices and production and non-cash fair value income from commodity derivatives in 2008 more than offset the higher expenses.

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

Acquisition and Sale Update. See Capital Resources and Liquidity for information about the cancelled acquisition of Conroe Field, the pending acquisition of Hastings Field and changes in the likelihood of our being able to sell our Barnett Shale properties.

Overview of Tertiary Operations. Oil production from our tertiary operations increased to an average of 19,784 BOE/d in the third quarter of 2008, a 23% increase over the third quarter 2007 tertiary production level of 16,101 BOE/d and a 6% increase over our second quarter 2008 tertiary production level, even though our third quarter 2008 average was reduced by approximately 550 Bbls/d as a result of production deferred due to two hurricanes. For a further discussion, see the section entitled CO_2 Operations below and contained in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2007 Form 10-K.

Increased Bank Credit Line. In early October 2008, we amended our bank credit facility, which increased the banks commitment amount from $350 million to $750 million and maintained our borrowing base at $1.0 billion. 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.

The bank amendment also (i) allowed us to divest of our Barnett Shale properties, (ii) allowed us to do a tax free like-kind exchange of the Barnett Shale properties for Conroe, Hastings and other fields, (iii) allowed for additional permitted indebtedness of up to $600 million in the form of subordinated or convertible debt, and (iv) modified the commitment fees and pricing grid for the loan, raising the pricing grid by 25 basis points. At the present time, we have decided not to pursue the issuance of any additional subordinated or convertible debt, and we believe that the sale of the Barnett Shale properties is doubtful in the current market which means it is unlikely that we will enter into a tax free like-kind exchange (see Capital Resources and Liquidity).

Genesis Transactions. On May 30, 2008, we closed two transactions with Genesis Energy, L.P. (Genesis) involving our NEJD and Free State CO_2 Pipelines, which included a long-term transportation service arrangement for the Free State Pipeline and a 20-year financing lease for the NEJD system. We received from Genesis $225 million in cash and $25 million of Genesis common limited partnership units (1,199,041 units at an average price of $20.85 per unit). These transactions were treated as financing leases for accounting purposes, with the assets and liabilities recorded on our balance sheet. We currently project that we will initially pay Genesis approximately $30 million per annum under the financing lease and transportation services agreement (a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependent on the volumes of CO_2 transported therein, with a minimum annual payment thereon of $1.2 million.

Change in Tax Accounting Method for Certain Tertiary Costs. During the third quarter, we obtained approval from the Internal Revenue Service (IRS) to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. Previously, we had capitalized and depreciated these costs, but now we can deduct these costs once the assets are placed into service. As a result, we expect to receive tax refunds of approximately $10.6 million for tax years through 2007 and we have reduced our estimated current income tax for 2008 to adjust for the impact of this change. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. This change is not expected to have a significant impact on our overall tax rate; however, we expect that it will reduce the amount of cash taxes we will pay over the next several years.

Our acceleration of tax deductions and resultant lower current cash income taxes will change the overall economics of certain financing-type transactions we have historically utilized, primarily equipment lease financing and certain transactions with Genesis (see paragraph below). For several years, we have entered into seven or ten year operating leases for certain equipment used in our tertiary production facilities. Through June 30, 2008, we had leased approximately $104.5 million of such equipment and had anticipated leasing additional equipment during 2008. In order to fully take advantage of the change in tax accounting, we have discontinued this leasing program, which is estimated to increase our 2008 capital budget by approximately $78 million, with the offset being a reduction of future lease operating expenses. However, if commodity prices remain low and capital resources remain limited, we may resume this leasing program in 2009 by leasing up to $100 million in equipment during the year, assuming that we can obtain lease financing on a favorable basis.

DENBURY RESOURCES INC.

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

The economic impact of our acceleration of tax deductions will also likely lead us to eliminate certain types of future asset drop-downs to Genesis. Transactions which are not sales for tax purposes, such as the recent $175 million financing lease on the NEJD CO_2 Pipeline (see Overview Genesis Transactions above) would not be affected provided that they meet other necessary tax structuring criteria. Those transactions which constitute a sale for tax purposes, such as the recent $75 million sale and associated long-term transportation service agreement entered into with Genesis on our Free State CO_2 Pipeline (see Overview - Genesis Transactions above), are likely to be discontinued.

Sale of Louisiana Natural Gas Assets. We completed the remaining 30% of the sale of our Louisiana natural gas assets in February 2008 with additional proceeds received at that time of approximately $48.9 million, the prior 70% of which closed in December 2007. Production attributable to the sold properties averaged 302 BOE/d (approximately 81% natural gas) during the first quarter of 2008, representing the production prior to the closing date for the portion of the sale that closed in February. Production attributable to the sold properties averaged approximately 30.6 MMcfe/d (82% natural gas) during the fourth quarter of 2007, representing approximately 10% of our total fourth quarter production and approximately 4% of our total proved reserve quantities as of December 31, 2006.

Capital Resources and Liquidity

In early October 2008, we announced several steps we had taken to improve our liquidity as a result of current conditions in the capital markets. These included an increase to our bank commitment amount as discussed above (see Overview Increased Bank Credit Line), cancellation of the $600 million acquisition of Conroe Field, purchase of oil derivative contracts covering approximately 75% to 80% of our currently estimated 2009 oil production, and reduction of our capital budget for 2009.

Prior to the recent decline in economic conditions we were intending to do a tax free exchange of the Barnett Shale properties for Conroe Field and Hastings Field, both future tertiary flood candidates located near Houston, Texas. However, because of the current capital market conditions, we believe that the sale of our Barnett Shale properties at a price that we would consider reasonable is doubtful, and without the certainty of a Barnett Shale property sale, we did not feel comfortable increasing our leverage in the current environment. As such, we cancelled our contract to purchase Conroe Field for $600 million, forfeiting a $30 million non-refundable deposit. To further protect our liquidity in the event that commodity prices continue to decline, we purchased oil derivative contracts for 2009 with a floor price of $75 / Bbl and a ceiling price of $115 / Bbl for total consideration of $15.5 million. The collars cover 30,000 Bbls/d representing between 75% and 80% of our currently anticipated 2009 oil production including anticipated production from Hastings Field, but excluding any liquid production from our Barnett Shale assets.

In September 2008, we exercised our option with a subsidiary of Venoco, Inc. (Venoco) to purchase the Hastings Field located near Houston, Texas, a potential tertiary oil field to be supplied by the Green Pipeline which is about to commence construction. The purchase price is to be determined by mutual agreement between the two companies, or failing agreement by December 1, 2008, by following a prescribed contractual formula based upon the present discounted value (PV10 Value) of the field s proved reserves as determined by the independent engineering firm of DeGolyer and MacNaughton, using year-end 2008 strip prices. The acquisition will be effective January 1, 2009 and is expected to close in early February 2009. Venoco agreed to extend the deadlines for capital expenditures, commencement of CO_2 injections and certain other contractual requirements by one year in consideration of us exercising the option in 2008 rather than 2009. Since this acquisition will likely be based upon year-end prices, we are not sure what the purchase price will be. Based on commodity prices as of the end of October 2008, the estimated purchase price is between $150 million and $250 million, assuming that Venoco does not exercise its option to take a volumetric production payment in lieu of a cash payment.

We currently estimate that our 2008 total capital spending will be between $900 million and $950 million, less than our current budget of $1.0 billion, although a portion of these costs will be carried over into 2009. When we announced our preliminary 2009 capital budget of $825 million in early October, that budget did not include any expenditures for the Barnett Shale (as it was presumed that these properties would have been sold), nor did it consider any possible carryover items from 2008. If such items were included, the total capital budget would be almost

$1.0 billion. In light of the continued lack of liquidity in the capital markets and the further deterioration of commodity prices, we have further revised our all inclusive 2009 capital budget downward by $250 million to $750 million. The revised 2009 capital

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budget retains approximately $485 million relating to our CO_2 pipelines, the majority of which is for the Green Pipeline. The budget also assumes that we fund approximately $100 million of the budgeted equipment purchases with operating leases, a practice we had discontinued a few months ago as a result of our favorable tax ruling (see Overview Change in Tax Accounting Method for Certain Tertiary Costs). Use of these operating leases is subject to locating acceptable financing, which we do not have at this time. The revised 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 $65.00 per barrel oil and $6.50 per Mcf natural gas prices, we anticipate that our capital expenditures could exceed projected cash flow by $150 million to $200 million, excluding any acquisitions. We anticipate funding this shortfall during 2009, along with the pending Hastings acquisition, with our bank credit line, which currently has $750 million of availability. We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, should our cash flow be less than expected, we would plan to reduce our capital expenditures to the extent possible during the year, which could in turn, have the impact of reducing our anticipated production levels in future years. For 2009, we have contracted for certain capital expenditures, including a portion of the Green Pipeline and two drilling rigs, but estimate that we could eliminate approximately $344 million of our 2009 projected expenditures if necessary without penalty (see also Off-Balance Sheet Arrangements Commitments and Obligations) and, if necessary, an additional $332 million (relating to the Green Pipeline) could be eliminated, subject to an estimated penalty of $26 million.

Based on our long-term models and assuming only the properties that we currently own, we expect our future capital spending to decrease significantly in 2010 from 2008 and 2009 levels. Therefore, even 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 in order to preserve our liquidity as necessary, although any spending reductions from our current long-term plans would likely lower our anticipated rate of production growth.

As part of our recent bank amendment (see Overview Increased Bank Credit Line), our bank borrowing base was reaffirmed at $1.0 billion. This borrowing base is higher than our current bank commitment of $750 million and assumed that our Barnett Shale properties were to be sold and that we would issue an additional $600 million in subordinated or convertible debt. While bank borrowing bases are likely to be reduced in the future to reflect the recent reduction in commodity prices, with the $250 million cushion between our borrowing base and commitment amount and the incremental value added by retaining our Barnett Shale properties (which are not expected to be sold at this time), we do not expect our bank commitment level to be reduced below $750 million unless prices were to further decrease significantly from current prices of approximately $65.00 per barrel for oil and $6.50 per Mcf for natural gas. As of October 31, 2008, we had outstanding $525 million (principal amount) of subordinated notes and no bank debt and approximately $75 million of cash on hand.

We continue to pursue acquisitions of mature oil fields that we believe have potential as future tertiary flood candidates, although with the general lack of liquidity in the capital markets, we currently have no plans to make any significant acquisitions until capital is more readily available, other than the Hastings Field as previously discussed.

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Sources and Uses of Capital Resources

	Nine Months Ended September 30,	
Amounts in thousands	2008	2007
Capital expenditures		
Oil and natural gas exploration and development		
Drilling	$ 186,249	$ 248,718
Geological, geophysical and acreage	14,084	16,624
Facilities	117,423	89,372
Recompletions	104,476	102,490
Capitalized interest	13,639	12,917
Total oil and gas exploration and development expenditures	435,871	470,121
Oil and natural gas property acquisitions	4,262	44,701
Total oil and natural gas capital expenditures	440,133	514,822
CO_2 capital expenditures, including capitalized interest	236,433	102,408
Total	$ 676,566	$ 617,230

Our capital expenditures for the first nine months of 2008 were funded with $632.8 million of cash flow from operations, $225 million from the drop-down of CO_2 pipelines to Genesis, and $48.9 million of proceeds from the second closing on our Louisiana property sale. The excess cash generated from these sources was used to repay our outstanding bank debt of $150 million, while the remainder of this excess increased our cash balances.

Our 2007 capital expenditures were funded with $364.8 million of cash flow from operations, $150.0 million from our issuance of subordinated debt in April 2007, $96.0 million of net bank borrowings, and the balance funded with working capital.

Off-Balance Sheet Arrangements

Commitments and Obligations

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

During the second quarter of 2008, we entered into transactions with Genesis relating to two of our CO_2 pipelines (see Overview Genesis Transactions above). As a result of these two transactions, we currently project that we will initially pay Genesis approximately $30 million per annum under the financing lease and transportation services agreement (a lesser pro-rated amount for 2008), with future payments for the NEJD pipeline fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependent on the volumes of CO_2 transported therein, with a minimum annual payment thereon of $1.2 million.

During the second quarter of 2008, we entered into a long-term commitment to purchase manufactured CO_2 from a proposed gasification plant in Kentucky proposed by Cash Creek Generation LLC and cancelled a contract we had executed for a proposed facility in Beaumont which we do not expect to be constructed. The plant proposed by Cash Creek is not only conditioned on that plant being built, but also upon Denbury contracting additional volumes of CO_2 for purchase in the general area of the proposed plant which aggregate 600 MMcf/d in order to justify the cost of a

CO_2 pipeline. Both the new contract and the cancelled contract called for production of approximately 200 MMcf/d of CO_2 and the delivered price of CO_2 in both contracts is similar. If this most recently proposed plant and the other two proposed plants are built, the aggregate purchase obligation for CO_2 from our contracted potential synthetic sources could be up to $150 million per year, assuming a $75 per barrel oil price and comparable compression levels, before any potential savings from our share of any carbon emissions credits enacted. 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 possible that not every plant currently under contract will be built, there are several other plants under consideration that may be built and concerning which we are having ongoing negotiations. These amounts were not included in the commitment table included in our Form 10-K as these payments are contingent on the plants being built.

During the third quarter of 2008, we exercised our option to purchase Hastings Field (see Capital Resources and Liquidity Pending Hastings Acquisition). The purchase price for this acquisition is not yet known as it will be based upon commodity prices as of December 31, 2008, but based on prices as of the end of October 2008, the purchase price is estimated to be between $150 million and $250 million.

We have committed to certain contracts relating to the construction of our proposed Green Pipeline being built from Louisiana to Texas with an aggregate of approximately $389 million which is expected to be incurred during 2009 under these contracts. We can eliminate $332 million of these contracts if necessary, subject to an estimated penalty of $26 million.

Neither the amounts nor the terms of any other commitments or contingent obligations have changed significantly from the year-end 2007 amounts reflected in our Form 10-K filed in February 2008, except for the transactions with Genesis noted above. Please refer to the Management s Discussion and Analysis of Financial Condition and Results of Operations Off-Balance Sheet Arrangements-Commitments and Obligations contained in our 2007 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 2007 Form 10-K for further information regarding these matters.

During the remainder of 2008 and 2009, we plan to drill five additional CO_2 source wells to further increase our production capacity and reserves. We estimate that we are currently capable of producing between 750 MMcf/d and 850 MMcf/d of CO_2, but anticipate this increasing to almost 1 Bcf/d by year-end 2008. During the third quarter of 2008, our CO_2 production averaged 630 MMcf/d, as compared to an average of approximately 596 MMcf/d during the second quarter of 2008, and average production of 593 MMcf/d during the first nine months of 2008. We used 85% of this production, or 507 MMcf/d, in our tertiary operations during the first nine months of 2008, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments.

Oil production from our tertiary operations increased to an average of 19,784 BOE/d in the third quarter of 2008, a 23% increase over the third quarter 2007 tertiary production level of 16,101 BOE/d and a 6% increase over the second quarter 2008 tertiary production level of 18,661 BOE/d, even though our third quarter 2008 average was reduced by approximately 550 Bbls/d as a result of production deferred (primarily in our Phase I properties) because of two hurricanes (see further discussion about the impact of the two hurricanes under Results of Operations Operating Results Production).

The table below shows our tertiary oil production by field for the first three quarters of 2008 and all four quarters of 2007. We saw our initial production from Tinsley Field (Phase III) in the second quarter of 2008, with tertiary production there averaging 675 Bbls/d during the second quarter and increasing to 1,518 Bbls/d during the third quarter. As a result

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of this production response to our CO_2 injections, we recognized approximately 29.8 MMBbls of proved reserves at Tinsley Field in the second quarter of 2008, although we do not believe that these proved reserve quantities represent the total ultimate reserves we expect to recover from this field with tertiary operations. During the third quarter of 2008, we had our initial production from Lockhart Crossing Field, and correspondingly recognized approximately 4.2 MMBbls of proved reserves at this field in the third quarter. The majority of the remaining production increase came from our Phase II operations in eastern Mississippi (Soso, Eucutta and Martinville Fields) which contributed 2,394 BOE/d (approximately two-thirds) to the increase over the prior year s third quarter production.

	Average Daily Production (BOE/d)						
Tertiary Oil Field	First Quarter 2007	Second Quarter 2007	Third Quarter 2007	Fourth Quarter 2007	First Quarter 2008	Second Quarter 2008	Third Quarter 2008
Phase I:							
Brookhaven	1,422	1,794	2,452	2,507	2,638	2,714	2,772
Little Creek area	2,117	1,974	2,011	1,957	1,807	1,661	1,556
Mallalieu area	5,470	5,802	5,823	6,304	6,099	6,260	5,339
McComb area	1,811	1,884	1,853	2,096	1,632	1,818	2,061
Lockhart Crossing							182
Phase II:							
Martinville	320	521	1,101	883	793	715	736
Eucutta	614	1,338	2,035	2,572	2,699	2,933	3,262
Soso	25	370	826	1,109	1,488	1,885	2,358
Phase III:							
Tinsley						675	1,518
Total tertiary oil production	11,779	13,683	16,101	17,428	17,156	18,661	19,784

We spent approximately $0.25 per Mcf to produce our CO_2 during the first nine months of 2008, an increase over our average for the first nine months of 2007 of $0.21 per Mcf. On a quarterly basis, we spent approximately $0.26 per Mcf to produce our CO_2 during the third quarter of 2008, down slightly from the $0.27 per Mcf spent in the second quarter of 2008, as compared to $0.23 per Mcf in the third quarter of 2007, with the higher cost in the 2008 period due to higher operating costs and higher oil costs which impacts the amount we pay royalty owners for the CO_2. Our estimated total cost per thousand cubic feet of CO_2 during the first nine months of 2008 was approximately $0.33, after inclusion of depreciation and amortization expense, higher than the 2007 nine month average of $0.29 per Mcf. Our estimated total cost per thousand cubic feet of CO_2 during the third quarter of 2008 was approximately $0.35, after inclusion of depreciation and amortization expense.

Since the most significant component of our operating cost, the cost of CO_2, has significantly increased along with oil prices as outlined above, and the second largest component of our tertiary operating expenses, power and fuel, also generally follow the same trend as commodity prices, our operating costs per BOE for our tertiary properties have generally increased during the last couple of years. While commodity prices trended down during the third quarter of 2008, average oil prices were only slightly less in the third quarter of 2008 than in the second quarter of 2008. We would expect to see some savings on operating costs commencing in the fourth quarter of 2008, assuming commodity prices remain low or continue to decrease. During the third quarter of 2008, we spent approximately $12.6 million on CO_2, or approximately $6.95 per tertiary barrel of oil, and spent approximately $10.4 million on power and fuel, or approximately $5.69 per tertiary barrel of oil.

Higher rental lease payments on equipment that we have historically leased (see Overview Change in Tax Accounting Method for Certain Tertiary Costs regarding future leasing activities) and rising labor costs also contributed to escalating costs, although the timing of new floods and field production levels can also have a significant impact on the per BOE amounts. During the third quarter of 2008, we also incurred an incremental $4.0 million (approximately $2.20 per tertiary barrel of oil) in workover costs, primarily related to remedial well work to repair tubing at Eucutta Field. Operating costs per BOE on our tertiary operations averaged $20.81, $24.67, and $26.81 during the first, second, and third quarters of 2008 as compared to $20.27, $20.47, and $18.65 during the first, second and third quarters of 2007,

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respectively. Operating costs on our tertiary operations averaged $19.71 per BOE during the first nine months of 2007 as compared to $24.25 per BOE during the first nine months of 2008.

Prior to January 1, 2008, we expensed all costs associated with injecting CO_2 used in our tertiary recovery operations, even though some of these costs were incurred prior to any tertiary related oil production. Commencing January 1, 2008, we began capitalizing, as a development cost, injection costs in fields that are in their development stage, which means we have not yet seen incremental oil production due to the CO_2 injections (i.e. a production response). These capitalized development costs are included in our unevaluated property costs if there are not already proved tertiary reserves in that field. After we see a production response to the CO_2 injections (i.e. the production stage), injection costs will be expensed as incurred, and any previously deferred unevaluated development costs will become subject to depletion upon recognition of proved tertiary reserves. Since we are continuing to initiate new tertiary floods, this means that we are now capitalizing certain costs that we historically expensed. Had we continued with the prior accounting methodology of expensing all tertiary injection costs, we would have expensed an additional $2.9 million or $1.84 per BOE (tertiary properties only) during the first quarter of 2008, as there were injection costs during the period in new tertiary floods without tertiary related oil production, primarily in the two new tertiary floods at Tinsley and Lockhart Crossing Fields. The amount of capitalized injection costs that we historically would have expensed was reduced during the second quarter of 2008 as we began to expense the injection costs at Tinsley Field when we commenced tertiary oil production in April, which contributed to the rise in operating costs per BOE between the first and second quarters of 2008. During the third quarter of 2008, we began to expense the CO_2 injection costs at Lockhart Crossing Field when we commenced tertiary oil production in July of 2008. In the third quarter of 2008, we would have expensed an additional $1.1 million or $0.62 per BOE (tertiary properties only) had we followed our prior year s accounting methodology. During the first nine months of 2007, the accounting methodology was not material, as only $1.5 million would have been capitalized under the new accounting procedure.

Operating Results

As summarized in the Overview section above and discussed in more detail below, for the third quarter of 2008, higher production, higher commodity prices and non-cash fair value income adjustments for commodity derivative contracts more than offset overall higher expenses, resulting in record quarterly earnings and a quarterly record cash flow from operations. On a nine month basis, the same trend applied, resulting in significant increases in our operating results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands, except per share amounts	2008	2007	2008	2007
Net income	$157,548	$ 67,988	$344,603	$147,171
Net income per common share basic	0.64	0.28	1.41	0.61
Net income per common share diluted	0.63	0.27	1.36	0.59
Cash flow from operations	262,442	169,214	632,771	364,811

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2008 and 2007 are included in the following table:

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	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Average daily production volumes				
Bbls/d	31,078	28,680	30,859	26,319
Mcf/d	89,009	102,239	89,087	94,129
BOE/d [1]	45,913	45,720	45,707	42,007
Operating revenues (in thousands)				
Oil sales	$ 321,965	$ 190,685	$ 899,368	$ 459,995
Natural gas sales	80,143	57,528	229,180	174,831
Total oil and natural gas sales	$ 402,108	$ 248,213	$ 1,128,548	$ 634,826
Oil and gas derivative contracts [2] (in thousands)				
Cash receipt (payment) on settlements of derivative contracts	$ (24,072)	$ 9,414	$ (60,714)	$ 19,384
Non-cash fair value adjustment income (expense)	86,079	(5,441)	17,123	(27,269)
Total income (expense) from oil and gas derivative contracts	$ 62,007	$ 3,973	$ (43,591)	$ (7,885)
Operating expenses (in thousands)				
Lease operating expenses	$ 85,308	$ 59,323	$ 228,134	$ 167,087
Production taxes and marketing expenses [3]	19,335	12,676	56,601	33,266
Total production expenses	$ 104,643	$ 71,999	$ 284,735	$ 200,353
Non-tertiary CO_2 operating margin (in thousands)				
CO_2 sales and transportation fees [4]	$ 3,471	$ 3,594	$ 9,705	$ 10,079
CO_2 operating expenses	(1,240)	(1,304)	(2,836)	(3,211)
Non-tertiary CO_2 operating margin	$ 2,231	$ 2,290	$ 6,869	$ 6,868
Unit prices including impact of derivative settlements [2]				
Oil price per Bbl	$ 108.70	$ 71.12	$ 102.74	$ 63.46
Gas price per Mcf	8.21	7.44	8.16	7.71
Unit prices excluding impact of derivative settlements [2]				

Oil price per Bbl	$ 112.61	$ 72.27	$ 106.37	$ 64.02
Gas price per Mcf	9.79	6.12	9.39	6.80
Oil and gas operating revenues and expenses per BOE (1)				
Oil and natural gas revenues	$ 95.20	$ 59.01	$ 90.11	$ 55.36
Oil and gas lease operating expenses	$ 20.20	$ 14.10	$ 18.22	$ 14.57
Oil and gas production taxes and marketing expense	4.58	3.01	4.52	2.90
Total oil and gas production expenses	$ 24.78	$ 17.11	$ 22.74	$ 17.47

(1) Barrel of oil equivalent using the ratio of one barrel of oil to 6 Mcf of natural gas (BOE).

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

(3) Includes Transportation expense Genesis.

(4) Includes deferred revenue of $1.2 million for each of the three months ended September 30, 2008 and 2007, and $3.4 million and $3.3 million for the nine months ended September 30, 2008 and 2007, respectively,

associated with a volumetric production payment with Genesis. Includes transportation income from Genesis of $1.5 million for each of the three months ended September 30, 2008 and 2007, and $4.1 million and $3.8 million for the nine months ended September 30, 2008 and 2007, respectively.

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Production: Production by area for each of the quarters of 2007 and the first, second, and third quarters of 2008 is listed in the following table.

	Average Daily Production (BOE/d)						
Operating Area	First Quarter 2007	Second Quarter 2007	Third Quarter 2007	Fourth Quarter 2007	First Quarter 2008	Second Quarter 2008	Third Quarter 2008
Mississippi CO_2 floods	11,779	13,683	16,101	17,428	17,156	18,661	19,784
Mississippi non - CO_2 floods	12,738	12,525	12,131	12,530	12,128	11,617	11,694
Texas	6,989	9,048	10,695	13,488	13,522	14,068	12,701
Onshore Louisiana	5,591	5,391	5,546	5,638	905	663	512
Alabama and other	1,208	1,269	1,247	1,287	1,189	1,296	1,222
Total Company	38,305	41,916	45,720	50,371	44,900	46,305	45,913

While we suffered minimal physical damage as a result of Hurricanes Gustav and Ike, we did shut-in and defer production during the third quarter of 2008 as a result of each of these storms. During Hurricane Gustav, we temporarily lost electrical power at most of our Phase I tertiary oil floods in Southwest Mississippi and as a result of Hurricane Ike, over half of our Barnett Shale production was temporarily shut-in as refineries on the Gulf Coast were unable to accept natural gas liquids production from the Barnett. We estimate that our total deferred tertiary oil production as a result of the two hurricanes ranged between 45,000 and 55,000 Bbls (approximately 550 Bbls/d for the third quarter estimated daily production using the mid-point of the estimate) and that our total deferred production was between 110,000 and 120,000 BOEs (approximately 1,250 BOE/d for the third quarter daily production using the mid-point of the estimate).

As outlined in the above table, adjusting for the impact of the deferred production as a result of the two hurricanes discussed above and the sale of our Louisiana natural gas properties in December 2007 and February 2008 see Overview Sale of Louisiana Natural Gas Assets , production in the third quarter of 2008 increased 16% (6,449 BOE/d) over third quarter of 2007 levels, and 26% in the first nine months of 2008 compared to production in the first nine months of 2007. The production increases were primarily due to increased production from our tertiary operations, coupled with production increases in the Barnett Shale. The increase in our tertiary operations is discussed above under Results of Operations CO_2 Operations .

Production in the Mississippi non-CO_2 floods area has fluctuated somewhat from quarter to quarter, but is generally on a slight decline, as our continued drilling activity developing the Selma Chalk natural gas reservoir in the Heidelberg and Sharon areas has helped offset the gradual declines in oil production.

Our Barnett Shale production has leveled off as our steady drilling program is generally maintaining a consistent production level. During 2006 and 2007, we drilled between 45 and 50 wells each year and we plan to do the same in 2008. Since these wells are characterized by high depletion rates, particularly in their first year of production, we anticipate that we will maintain a relatively steady production level there during 2008 at this drilling pace. This trend is evident in that the Barnett Shale production has remained relatively unchanged since the fourth quarter of 2007, if adjusted for the deferred production in the third quarter of 2008 related to the hurricanes. Production for the third quarter of 2008 averaged 12,339 BOE/d (down about 650 BOE/d related to deferred production from the hurricanes) as compared to 10,063 BOE/d for the comparative third quarter of 2007, 12,729 BOE/d in the fourth quarter of 2007, 12,801 BOE/d in the first quarter of 2008 and 13,434 BOE/d in the second quarter of 2008. The Texas property acquisition we made late in the first quarter of 2007 contributed approximately 336 BOE/d to the third quarter 2008 production, less than the 634 BOE/d added during the second quarter of 2008 as a portion of this production was also deferred because of the two hurricanes.

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Our production for the third quarter of 2008 was weighted toward oil (68%), about the same as our proportion of oil production during the third quarter of 2007, as the increases in natural gas production in the Barnett Shale area, offset by the sale of our natural gas assets in Louisiana, generally have been matched by increases in our tertiary oil production.

Oil and Natural Gas Revenues: Oil and natural gas revenues for the third quarter of 2008 increased $153.9 million, or 62%, from revenues in the comparable quarter of 2007, primarily as a result of higher commodity prices, accompanied by slightly higher production levels. The increase in production volumes in the third quarter of 2008 increased oil and natural gas revenues by $1.0 million, while the increase in overall commodity prices in the third quarter of 2008 increased revenues by $152.8 million, or 62%, over prior year s third quarter levels. When comparing the respective nine month periods, revenues increased $493.7 million, or 78%, due to both increased prices and production. The increase in production during the first nine months of 2008 increased revenues by $58.4 million, or 9%, while the increase in overall commodity prices during the first nine months of 2008 increased oil and natural gas revenues by $435.3 million, or 69% over the prior year s first nine months levels.

Excluding any impact of our derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second and third quarters and first nine months periods of 2007 and 2008:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007	2008	2007	2008	2007
Net Realized Prices:								
Oil price per Bbl	$91.24	$54.57	$114.67	$63.48	$112.61	$72.27	$106.37	$64.02
Gas price per Mcf	7.80	6.63	10.55	7.71	9.79	6.12	9.39	6.80
Price per BOE	76.65	49.06	98.07	57.02	95.20	59.01	90.11	55.36
NYMEX differentials:								
Oil per Bbl	$ (6.50)	$ (3.73)	$ (9.64)	$ (1.61)	$ (6.06)	$ (2.91)	$ (7.23)	$ (2.22)
Natural Gas per Mcf	(0.90)	(0.51)	(0.93)	0.07	0.75	(0.10)	(0.35)	(0.19)

Our oil NYMEX differential to prices received was the lowest in our corporate history during the first three quarters of 2007. The improved NYMEX differential during 2007 was related to higher prices received for both our light sweet barrels and our sour barrels primarily as a result of NYMEX (WTI) prices being depressed due to lack of available storage capacity in the mid-continent area, an oversupply of crude from Canada, capacity/transportation issues in moving crude oil out of the Cushing, Oklahoma area and unanticipated refinery outages. This trend reversed itself by the fourth quarter of 2007, with average NYMEX oil differentials during that quarter of $ (7.27) per Bbl, higher than our historical averages due to the significant increase in liquids extracted from our natural gas production in the Barnett Shale, which is recorded as oil production but sells at a significant discount to NYMEX. The differentials for the first quarter of 2008 improved only slightly over fourth quarter of 2007 levels, but widened to one of the highest differentials in our corporate history in the second quarter of 2008 to $(9.64) per Bbl as the differentials on the heavier sour crudes and the Barnett Shale liquid production widened as oil prices increased. The differentials for the third quarter of 2008 returned to first quarter 2008 levels as oil prices began to decline during the period.

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 the month. While the percentage change in the above table is quite large, these differentials are very seldom more than a dollar above or below the NYMEX amount.

Oil and Natural Gas Derivative Contracts: We made cash payments of $24.1 million on settlements of our oil and natural gas derivative contracts during the third quarter of 2008, as compared to net cash receipts of $9.4 million during the third quarter of 2007, a negative differential of $33.5 million. Approximately 46% of the payments made during the third quarter of 2008 related to the 2,000 Bbls/d oil swaps for 2008 entered into when we made a large acquisition in January 2006, and the balance is due to natural gas swaps for 2008. On a nine month basis, we made cash payments of $60.7 million on settlements of our oil and natural gas derivative contracts during the 2008 period, as compared to net cash receipts of $19.4 million during the first nine months of 2007, a negative differential of $80.1 million.

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Approximately 51% of the payments made during the first nine months of 2008 related to the 2,000 Bbls/d oil swaps and the balance to the natural gas swaps.

Our total non-cash mark-to-market income was $86.1 million during the third quarter of 2008, as compared to mark-to-market expense of $5.4 million during the third quarter of 2007, with the 2008 income primarily attributable to falling commodity prices during the quarter. On a nine month basis, our total mark-to-market income was $17.1 million during the first nine months of 2008, as compared to mark-to-market expense of $27.3 million during the first nine months of 2007. During the 2008 periods, both oil and natural gas prices increased during the first half of the year and then declined during the third quarter of 2008, ending the period at levels lower than at the beginning of the year. During the first nine months of 2007, natural gas prices fluctuated, causing a mark-to-market value charge for the first nine month period, comprised of a significant charge during the first quarter, income during the second quarter, and a modest charge in the third quarter. Because we do not utilize hedge accounting for our commodity derivative contracts, the adjustments in the fair value of these contracts are recognized currently in our income statement. See Market Risk Management for additional information regarding our derivative activities and Note 6 to the Unaudited Condensed Consolidated Financial Statements.

Production Expenses: Our lease operating expenses increased between the comparable first nine months and third quarters on both a per BOE basis and in absolute dollars, primarily as a result of trends evident in our tertiary operations as more fully discussed under CO_2 Operations above, as our tertiary operating expenses were approximately 57% of our total operating expenses during the third quarter of 2008 as compared to approximately 47% during the third quarter of 2007. Other factors such as higher overall industry costs and increased personnel and related costs also contributed to higher expenses.

During the third quarter of 2008, operating costs averaged $20.20 per BOE, up from $14.10 per BOE in the third quarter of 2007, and up from the $18.23 per BOE in the second quarter of 2008. The trends were similar when comparing the respective first nine month periods. A portion of the increase in per BOE expenses in the third quarter of 2008 resulted from the sale of our Louisiana natural gas properties in the fourth quarter of 2007 and first quarter of 2008. If the sold properties were excluded from the third quarter of 2007 results, our operating costs during that period would have been approximately $0.95 per BOE higher than reported, or $15.05 per BOE.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes and therefore were higher in the third quarter of 2008 than in the comparable quarter of 2007. Transportation and plant processing fees were approximately $2.1 million higher in the third quarter of 2008 than in the third quarter of 2007 and approximately $6.8 million higher for the first nine months of 2008 than in the first nine months of 2007.

General and Administrative Expenses

General and administrative (G&A) expenses increased 30% between the respective third quarters and increased 32% between the respective first nine months, as set forth below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands, except BOE data and employees	2008	2007	2008	2007
Net G&A expense				
Gross G&A expenses	$ 35,433	$ 28,412	$ 103,469	$ 83,554
State franchise taxes	863	705	2,548	2,163
Operator labor and overhead recovery charges	(18,027)	(15,041)	(50,788)	(43,741)
Capitalized exploration and development costs	(3,264)	(2,535)	(9,408)	(7,307)
Net G&A expense	$ 15,005	$ 11,541	$ 45,821	$ 34,669
Average G&A cost per BOE	$ 3.55	$ 2.74	$ 3.66	$ 3.02
Employees as of September 30	768	668	768	668

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Gross G&A expenses increased $7.0 million, or 25%, between the respective third quarters and $19.9 million, or 24%, between the respective first nine months. Approximately $4.6 million of the increase in gross G&A expenses between the respective quarters is related to increases in compensation and personnel related costs (approximately $17.1 million between the respective first nine months), due primarily to the increase in employees and salary increases, which we consider necessary in order to remain competitive in our industry. During 2007, we increased our employee count by 15% and we further increased our employee count by approximately 12% during the first nine months of 2008. Stock compensation expense reflected in gross G&A expenses was approximately $4.1 million for the third quarter of 2008 and $3.2 million for the third quarter of 2007. On a nine month basis, stock compensation was approximately $12.6 million for the first nine months of 2008 and $9.3 million for the first nine months of 2007. Due to increased competitive pressures in the industry, our wages have been increasing at a rate higher than general inflation and we expect this trend to continue.

The increase in gross G&A was offset in part by an increase in operator overhead recovery charges in the third quarter and first nine months of 2008. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells from acquisitions, additional tertiary operations, drilling activity during the past year and increased compensation expense, the amount we recovered as operator overhead charges increased by 20% between the third quarters of 2008 and 2007 and increased by 16% between the first nine months of 2008 and 2007. Capitalized exploration and development costs also increased by 29% between the third quarters of 2008 and 2007 and increased by 29% between the first nine months of 2008 and 2007, primarily as a result of increases in personnel and compensation costs.

The net effect was a 30% increase in net G&A expense between the respective third quarters and a 32% increase for these costs between the first nine months of 2008 and 2007. On a per BOE basis, G&A costs increased 30% in the third quarter of 2008 as compared to levels in the third quarter of 2007, and increased 21% between the comparative first nine months of 2008 and 2007.

Interest and Financing Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands, except per BOE amounts	2008	2007	2008	2007
Cash interest expense	$ 17,209	$ 13,529	$ 42,287	$ 35,321
Non-cash interest expense	410	530	1,225	1,523
Less: Capitalized interest	(6,713)	(5,431)	(19,524)	(13,785)
Interest expense	$ 10,906	$ 8,628	$ 23,988	$ 23,059
Interest income and other	$ 4,675	$ 1,702	$ 7,321	$ 5,269
Average net cash interest expense per BOE (1)	$ 2.10	$ 1.61	$ 1.59	$ 1.49
Average interest rate (2)	8.8%	7.5%	7.9%	7.5%
Average debt outstanding	$ 780,129	$ 736,596	$ 713,714	$ 640,916

(1) Cash interest expense, less capitalized interest, less interest and

other income on a BOE basis.

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

Interest expense increased $2.3 million, or 26%, comparing the third quarters of 2007 and 2008, and $0.9 million, or 4%, comparing levels in the first nine months of 2007 and 2008, primarily as a result of higher debt levels in the 2008 periods, partially offset by higher capitalized interest during the 2008 periods. Interest expense increased significantly during the third quarter of 2008 as a result of the two transactions with Genesis which were recorded as financing leases (see Overview Genesis Transactions) and which carry a higher imputed rate of interest. The higher rate of interest is partially offset by the cash distributions that we receive from Genesis which have increased from $0.3 million in the third

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quarter of 2007 to $2.1 million during the third quarter of 2008. However, the cash receipts related to distributions from Genesis are not recognized in our income statement but rather as an adjustment to our investment account.

Our interest capitalization increased in 2008 because of our growing balance of unevaluated property expenditures and higher overall interest rates. We discontinued the capitalization of interest at Tinsley Field after production commenced there in April 2008 and discontinued the capitalization of interest at Lockhart Crossing Field in the third quarter of 2008 after production commenced there in July 2008. However, we have continued to expend funds on our CO_2 pipelines and our average interest rate has increased as a result of the two Genesis transactions (see above paragraph).

Interest income increased during the third quarter of 2008 as a result of interest earned on the excess funds received from the two Genesis transactions.

Depletion, Depreciation and Amortization

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands, except per BOE amounts	2008	2007	2008	2007
Depletion and depreciation of oil and natural gas properties	$ 48,638	$ 47,347	$ 140,648	$ 124,290
Depletion and depreciation of CO_2 assets	4,047	2,966	10,673	8,408
Asset retirement obligations	762	746	2,286	2,232
Depreciation of other fixed assets	2,877	1,738	7,289	5,129
Total DD&A	$ 56,324	$ 52,797	$ 160,896	$ 140,059
DD&A per BOE:				
Oil and natural gas properties	$ 11.69	$ 11.43	$ 11.41	$ 11.03
CO_2 assets and other fixed assets	1.64	1.12	1.44	1.18
Total DD&A cost per BOE	$ 13.33	$ 12.55	$ 12.85	$ 12.21

Our depletion, depreciation and amortization (DD&A) rate for oil and natural gas properties on a per BOE basis increased 2% between the respective third quarters and increased 3% between the respective first nine months, primarily due to capital spending and increased costs. During the third quarter, the significant incremental reserves included approximately 4.2 MMBbls booked at Lockhart Crossing Field, a new tertiary flood with an initial production response in July 2008, and approximately 5.3 MMBOEs in the Barnett Shale. These incremental reserves were not as significant as those booked in the second quarter when we booked approximately 29.8 million barrels of incremental oil reserves related to our tertiary operations in Tinsley Field, following the oil production response to the CO_2 injections in that field in April 2008. At that time we correspondingly moved approximately $195 million from unevaluated properties to the full cost pool relating to Tinsley Field, representing a portion of the acquisition cost of that field and other expenditures incurred on the field prior to recognizing proved reserves. As a result of recognizing all of the unevaluated costs on that field and virtually all of the forecasted future capital costs, the recognition of proved reserves at Tinsley slightly increased our DD&A rate as the average net cost per barrel for the proved reserves was slightly higher than our prior average DD&A rate. We expect to recognize incremental proved reserves at Tinsley in the future, which we expect will bring the average ultimate cost per barrel at that field to less than $10 per barrel.

During the second quarter of 2008, we also moved approximately $37 million of equipment costs into our depletion calculation due to our decision to abandon our operating lease program following a change in tax accounting for certain tertiary costs (see Overview Change in Tax Accounting Method for Certain Tertiary Costs). This further increased our DD&A rate during the second and third quarters of 2008.

We continually evaluate the performance of our other tertiary projects, and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that

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quarter. Since we adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future.

Our DD&A rate for our CO_2 and other general corporate fixed assets increased in 2008 as compared to the rates during 2007, primarily as a result of expenditures related to the expansion of our corporate office space and the Tinsley, Lockhart and Gwinville CO_2 pipelines placed into service during 2008.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
Amounts in thousands, except per BOE amounts and tax rates	2008	2007	2008	2007
Current income tax expense	$ 12,689	$ 5,197	$ 44,769	$ 14,158
Deferred income tax expense	83,480	38,028	163,909	79,609
Total income tax expense	$ 96,169	$ 43,225	$ 208,678	$ 93,767
Average income tax expense per BOE	$ 22.77	$ 10.28	$ 16.66	$ 8.18
Effective tax rate	37.9%	38.9%	37.7%	38.9%

In the fourth quarter of 2007, we lowered our estimated statutory income tax rate to 38% from 39% as result of our sale of our Louisiana natural gas assets. During the nine months of 2008, our effective rate was further reduced primarily as a result of higher section 199 deductions because of our higher pretax income.

The Company recently obtained approval from the IRS to change its method of tax accounting for certain assets used in its tertiary oilfield recovery operations. Previously, the Company capitalized and depreciated these costs, but now it can deduct these costs once the assets are placed into service. As a result, the Company expects to receive tax refunds of approximately $10.6 million for tax years through 2007, and in the third quarter of 2008 has reduced its current income tax expense to adjust for the impact of this change. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it will reduce the amount of cash taxes the Company expects to pay over the next several 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.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
Per BOE data	2008	2007	2008	2007
Oil and natural gas revenues	$ 95.20	$ 59.01	$ 90.11	$ 55.36
Gain (loss) on settlements of derivative contracts	(5.70)	2.24	(4.84)	1.69
Lease operating expenses	(20.20)	(14.10)	(18.22)	(14.57)
Production taxes and marketing expenses	(4.58)	(3.01)	(4.52)	(2.90)
Production netback	64.72	44.14	62.53	39.58
Non-tertiary CO_2 operating margin	0.53	0.54	0.55	0.60
General and administrative expenses	(3.55)	(2.74)	(3.66)	(3.02)
Net cash interest expense	(2.10)	(1.61)	(1.59)	(1.49)
Abandoned acquisition costs	(7.20)		(2.43)	
Current income taxes and other	(2.41)	(0.68)	(2.93)	(0.66)
Changes in assets and liabilities relating to operations	12.14	0.58	(1.94)	(3.20)
Cash flow from operations	62.13	40.23	50.53	31.81
DD&A	(13.33)	(12.55)	(12.85)	(12.21)
Deferred income taxes	(19.76)	(9.04)	(13.09)	(6.94)
Non-cash commodity derivative adjustments	20.38	(1.29)	1.37	(2.38)
Changes in assets and liabilities and other non-cash items	(12.12)	(1.19)	1.56	2.55
Net income	$ 37.30	$ 16.16	$ 27.52	$ 12.83

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 no bank debt outstanding as of September 30, 2008 and $150 million outstanding at December 31, 2007. The fair value of the subordinated debt is based on quoted market prices. None of our debt has any triggers or covenants regarding our debt ratings with rating agencies, although under the NEJD financing lease with Genesis (See Overview Genesis Transactions) 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. See also Note 6 to the Unaudited Condensed Consolidated Financial Statements regarding the settlement of some minor interest rate lock derivative contracts. The following table presents the carrying and fair values of our debt as of September 30, 2008, along with average interest rates.

	Expected Maturity Dates		Carrying	Fair
Amounts in thousands	2013	2015	Value	Value
Fixed rate debt:				
7.5% subordinated debt due 2013 (fixed rate of 7.5%)	$225,000	$	$224,126	$212,625
7.5% subordinated debt due 2015 (fixed rate of 7.5%)		300,000	300,621	276,000

Oil and Gas Derivative Contracts

From time to time, we enter into various oil and 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. Historically, we hedged up to 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover most of our budgeted exploration and development expenditures without incurring significant debt. Since 2005 and beyond, we have generally entered into fewer derivative contracts, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations, although we have hedged certain products from time to time. In late 2006 we swapped 80% to 90% of our forecasted

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2007 natural gas production at a weighted average price of $7.96 per Mcf, and in September 2007 we swapped 70% to 80% of our remaining forecasted 2008 natural gas production (after the sale of our Louisiana natural gas properties) at a weighted average price of $7.91 per Mcf. We did this to protect our 2008 projected cash flow, primarily because we initially planned to spend $200 million to $250 million more than we expected to generate in cash flow from operations and we did not want to be exposed to the risk of lower natural gas prices. We cancelled the December 2008 natural gas swaps in the third quarter of 2008 because of our plans to sell our Barnett Shale properties, receiving approximately $61,000 from the cancellation.

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 / Bbl and a ceiling price of $115 / Bbl for total consideration of $15.5 million. The collars cover 30,000 Bbls/d representing between 75% and 80% of our currently anticipated 2009 oil production including anticipated production from Hastings Field, but excluding any natural gas liquids production from our Barnett Shale assets (see also Capital Resources and Liquidity). These 2009 contracts were entered into with the following counterparties: JPMorgan Chase Bank (10,000 Bbls/d), Wells Fargo Bank (7,500 Bbls/d), Keybank (5,000 Bbls/d), Fortis Energy Marketing and Trading GP (5,000 Bbls/d) and Comerica Bank (2,500 Bbls/d).

When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted proved production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. As of September 30, 2008, we had derivative contracts in place related to our $250 million acquisition that closed on January 31, 2006, on which we entered into contracts to cover 100% of the first three years of estimated proved producing production at the time we signed the purchase and sale agreement. These swaps cover 2,000 Bbls/d for remainder of 2008 at a price of $57.34 per Bbl.

At September 30, 2008, our derivative contracts were recorded at their fair value, which was a net liability of approximately $6.2 million, an increase in value of approximately $17.1 million from the $23.3 million fair value liability recorded as of December 31, 2007 (See Note 6 to Unaudited Condensed Consolidated Financial Statements for a complete listing of our derivative contract positions at September 30, 2008). This change is the result of both the expiration of contracts during the first nine months of 2008 and the decreases in both oil and natural gas commodity futures prices between December 31, 2007 and September 30, 2008.

Based on NYMEX crude oil futures prices at September 30, 2008, oil prices were considerably higher than the swap prices of our outstanding derivative contracts so we would expect to make future cash payments of $7.9 million on our oil commodity derivative contracts. If oil futures prices were to decline by 10%, the amount we would expect to pay under our oil commodity derivative contracts would decrease to $6.1 million, and if futures prices were to increase by 10% we would expect to pay $9.8 million. Based on NYMEX natural gas futures prices at September 30, 2008, we would expect to receive cash payments of $1.4 million on our natural gas commodity derivative contracts. If natural gas prices futures prices were to decline by 10%, we would expect to receive future cash payments of $4.2 million, and if futures prices were to increase by 10% we would expect to make future cash payments of $1.4 million.

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, accounting for tertiary injection costs, asset retirement obligations, income taxes, stock compensation plans and hedging activities, and which remain unchanged, 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, 2007. See also Overview Change in Tax Accounting Method for Certain Tertiary Costs and Results of Operations CO_2 Operations for discussions regarding changes in accounting policies and procedures during 2008.

Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

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. SFAS No. 161 is effective for us beginning January 1, 2009. We have not yet determined what impact, if any, this pronouncement will have on our disclosures about derivatives.

In October 2008, the FASB issued FSP FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active. FSP FAS 157-3 clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 is effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application should be accounted for as a change in accounting estimate following the guidance in FASB Statement No. 154, Accounting Changes and Error Corrections. FSP FAS 157-3 is effective for the financial statements included in the Company s quarterly report for the period ended September 30, 2008, and application of FSP FAS 157-3 had no impact on the Company s Unaudited Condensed Consolidated Financial Statements.

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in this Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, availability of capital, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in 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, or other words that convey the 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 annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company s other public reports, filings and public statements.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company s management, including the CEO and CFO. Based on that evaluation, the Company s CEO and CFO concluded that the Company s disclosure controls and procedures were effective as of September 30, 2008 to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company s management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

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

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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, 2007. 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 the risk factors has been incorporated by reference from Item 1A. of our Form 10-K for the year ended December 31, 2007. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plan Or Programs
July 1 through 31, 2008	198	$34.19		
August 1 through 31, 2008	141,150	$24.42		
September 1 through 30, 2008	6,758	$23.00		
Total	148,106	$24.37		

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)*	Second Amendment to Sixth Amended and Restated Credit Agreement among Denbury Onshore, LLC, as Borrower, and JPMorgan Chase Bank, N.A., as Administrative Agent, and certain other financial institutions dated as of October 7, 2008.
10(b)*	Option Agreement to Purchase Hastings Field By and Between Texcal Energy South Texas, L.P. and Denbury Onshore, LLC dated November 1, 2006.
10(c)*	First Amendment to Option Agreement, dated as of August 29, 2008, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC.
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.

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

Dated: November 7, 2008