DENBURY RESOURCES INC
Form 10-Q
August 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 June 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 July 31, 2008**
Common Stock, $.001 par value	246,910,322

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

	June 30, 2008	December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	$ 147,009	$ 60,107
Accrued production receivable	180,644	136,284
Trade and other receivables, net of allowance of $393 and $369	72,222	28,977
Deferred tax assets	45,083	12,708
Derivative assets		2,283
Total current assets	444,958	240,359
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	3,022,567	2,682,932
Unevaluated	275,338	366,518
CO_2 properties and equipment	545,497	436,591
Other	62,532	50,116
Less accumulated depletion and depreciation	(1,247,141)	(1,143,282)
Net property and equipment	2,658,793	2,392,875
Deposits on property under option or contract	49,162	49,097
Other assets	120,201	88,746
Total assets	$ 3,273,114	$ 2,771,077
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 126,613	$ 147,580
Oil and gas production payable	111,215	84,150
Derivative liabilities	92,286	28,096
Deferred revenue Genesis	4,070	4,070
Current maturities of long-term debt	3,838	737
Total current liabilities	338,022	264,633
Long-term liabilities		
Long-term debt Genesis	251,582	4,544
Long-term debt	525,596	675,786
Asset retirement obligations	42,230	38,954
Deferred revenue Genesis	22,242	24,424

Deferred tax liability	457,502	347,370
Other	11,272	10,988
Total long-term liabilities	1,310,424	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; 247,401,427 and 245,386,951 shares issued at June 30, 2008 and December 31, 2007, respectively	247	245
Paid-in capital in excess of par	693,935	662,698
Retained earnings	938,234	751,179
Accumulated other comprehensive loss	(661)	(1,591)
Treasury stock, at cost, 550,635 and 637,795 shares at June 30, 2008 and December 31, 2007, respectively	(7,087)	(8,153)
Total stockholders equity	1,624,668	1,404,378
Total liabilities and stockholders equity	$ 3,273,114	$ 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 June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues and other income				
Oil, natural gas and related product sales	$ 413,243	$ 217,479	$ 726,440	$ 386,613
CO_2 sales and transportation fees	3,383	3,394	6,234	6,485
Interest income and other	1,359	1,637	2,646	3,567
Total revenues	417,985	222,510	735,320	396,665
Expenses				
Lease operating expenses	76,825	57,207	142,826	107,764
Production taxes and marketing expenses	18,688	9,035	33,874	17,863
Transportation expense Genesis	1,842	1,351	3,392	2,727
CO_2 operating expenses	453	1,204	1,596	1,907
General and administrative	14,811	11,694	30,816	23,128
Interest, net of amounts capitalized of $5,545, $4,321, $12,811, and $8,354, respectively	8,141	8,356	13,082	14,431
Depletion, depreciation and amortization	54,733	46,235	104,572	87,262
Commodity derivative expense (income)	58,817	(15,049)	105,598	11,858
Total expenses	234,310	120,033	435,756	266,940
Income before income taxes	183,675	102,477	299,564	129,725
Income tax provision				
Current income taxes	10,844	7,343	32,080	8,961
Deferred income taxes	58,778	32,567	80,429	41,581
Net income	$ 114,053	$ 62,567	$ 187,055	$ 79,183
Net income per common share basic	$ 0.47	$ 0.26	$ 0.77	$ 0.33
Net income per common share diluted	$ 0.45	$ 0.25	$ 0.74	$ 0.32
Weighted average common shares outstanding				
Basic	243,623	239,586	243,189	238,789
Diluted	252,401	249,537	252,603	249,459

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Cash flow from operating activities:				
Net income	$ 114,053	$ 62,567	$ 187,055	$ 79,183
Adjustments needed to reconcile to net cash flow provided by operations:				
Depletion, depreciation and amortization	54,733	46,235	104,572	87,262
Deferred income taxes	58,778	32,567	80,429	41,581
Deferred revenue Genesis	(1,138)	(1,066)	(2,182)	(2,022)
Stock based compensation	3,499	2,664	7,385	5,450
Non-cash fair value derivative adjustments	29,875	(13,437)	69,003	21,721
Amortization of debt issue costs and other	(677)	963	(396)	1,545
Changes in assets and liabilities related to operations:				
Accrued production receivable	(38,325)	(23,550)	(44,359)	(22,070)
Trade and other receivables	(38,520)	(2,806)	(46,879)	(11,785)
Other assets	1,107	(124)	269	(146)
Accounts payable and accrued liabilities	(26,928)	(10,515)	(10,442)	(15,501)
Oil and gas production payable	9,431	7,782	27,065	9,211
Other liabilities	(1,816)	972	(1,191)	1,168
Net cash provided by operating activites	164,072	102,252	370,329	195,597
Cash flow used for investing activities:				
Oil and natural gas capital expenditures	(142,701)	(160,290)	(299,003)	(299,309)
Acquisitions of oil and gas properties	(1,955)	(7,523)	(2,357)	(46,660)
Change in accrual for capital expenditures	3,610	(4,514)	(5,999)	(8,769)
Distributions from Genesis	1,475		2,725	
Acquisitions of CO_2 assets and CO_2 capital expenditures	(66,324)	(37,011)	(108,850)	(68,427)
Net purchases of other assets	(6,652)	(1,837)	(16,931)	(2,734)
Net proceeds from sales of oil and gas properties and equipment	(5,196)	5,835	49,029	5,840
Other	(641)	(64)	(686)	(960)
Net cash used for investing activities	(218,384)	(205,404)	(382,072)	(421,019)
Cash flow from financing activities:				
Bank repayments	(131,000)	(140,000)	(222,000)	(140,000)
Bank borrowings	20,000	80,000	72,000	176,000
Payments on capital lease obligations	(182)	(166)	(360)	(327)
Income tax benefit from equity awards	8,729	6,280	14,143	8,840
Pipeline financing Genesis	225,248		225,248	
Issuance of subordinated debt		150,750		150,750
Issuance of common stock	4,556	5,477	9,710	10,687
Other	(69)	(1,619)	(96)	(1,824)

Net cash provided by financing activities	127,282	100,722	98,645	204,126
Net increase (decrease) in cash and cash equivalents	72,970	(2,430)	86,902	(21,296)
Cash and cash equivalents at beginning of period	74,039	35,007	60,107	53,873
Cash and cash equivalents at end of period	$ 147,009	$ 32,577	$ 147,009	$ 32,577
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest	$ 20,947	$ 18,970	$ 22,997	$ 21,349
Cash paid during the period for income taxes	55,999	6,332	58,629	7,370
Interest capitalized	5,545	4,321	12,811	8,354

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Net income	$ 114,053	$ 62,567	$ 187,055	$ 79,183
Other comprehensive income, net of income tax:				
Change in fair value of derivative contracts designated as a hedge, net of tax of $301, $364, $49 and $36, respectively	492	570	12	57
Interest rate lock derivative contracts reclassified to income, net of taxes of $551 and $562, respectively	900		918	
Comprehensive income	$ 115,445	$ 63,137	$ 187,985	$ 79,240

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q and do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. Unless indicated otherwise or the context requires, the terms we, our, us, Denbury or Compa refer to Denbury Resources Inc. and its subsidiaries. These financial statements and the notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 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 June 30, 2008 and the consolidated results of its operations and cash flows for the three and six month periods ended June 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 six month periods ended June 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 six month periods ended June 30, 2008 and 2007.

	Three Months Ended June 30,		Six Months Ended June 30,	
Shares in Thousands	2008	2007	2008	2007
Weighted average common shares basic	243,623	239,586	243,189	238,789
Potentially dilutive securities:				
Stock options and SARs	7,389	8,520	8,043	9,315
Restricted stock	1,389	1,431	1,371	1,355
Weighted average common shares diluted	252,401	249,537	252,603	249,459

The weighted average common shares basic amount excludes 2,668,538 shares at June 30, 2008 and 3,062,282 shares at June 30, 2007, of non-vested restricted stock that is subject to future vesting over time. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share (although all restricted stock is issued and outstanding upon grant). For purposes of calculating weighted

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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 June 30, 2008 and 2007, stock options to purchase approximately 49,000 and 159,000 shares of common stock, and for the six months ended June 30, 2008 and 2007, stock options to purchase approximately 691,000 and 314,000 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 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 and $1.4 million during the second quarter of 2008. During the first half of 2007, the impact of this accounting methodology was not material, as only $0.6 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.

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 minimizes 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:

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Notes to Unaudited Condensed Consolidated Financial Statements

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 June 30, 2008.

	Fair Value Measurements at June 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
Liabilities:				
Oil and natural gas derivative contracts	$	$92,286	$	$92,286

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 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 Gas Properties Divestiture

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, which we believe could potentially increase the ultimate value we receive by up to 10%. 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.

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Notes to Unaudited Condensed Consolidated Financial Statements

Note 3. Asset Retirement Obligations

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

The following table summarizes the changes in our asset retirement obligations for the six months ended June 30, 2008.

Amounts in thousands	Six Months Ended June 30, 2008
Balance, beginning of period	$ 41,258
Liabilities incurred and assumed during period	894
Revisions in estimated retirement obligations	1,072
Liabilities settled during period	(750)
Accretion expense	1,524
Sales	(63)
Balance, end of period	$ 43,935

At June 30, 2008, $1.7 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 six month period ended June 30, 2008 are primarily for oil and natural gas 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 were $9.6 million at June 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	June 30, 2008	December 31, 2007
7.5% Senior Subordinated Notes due 2015	$ 300,000	$ 300,000
Premium on Senior Subordinated Notes due 2015	642	685
7.5% Senior Subordinated Notes due 2013	225,000	225,000
Discount on Senior Subordinated Notes due 2013	(923)	(1,020)
NEJD Financing Genesis	175,000	
Free State Financing Genesis	75,248	
Senior bank loan		150,000
Capital lease obligations Genesis	4,900	5,238
Capital lease obligations	1,149	1,164
Total	781,016	681,067
Less current obligations	3,838	737

Long-term debt and capital lease obligations	$ 777,178	$ 680,330

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Notes to Unaudited Condensed Consolidated Financial Statements

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.

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. With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our 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 ($350 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.

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 $2.8 million and $0.6 million during the six months ended June 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 on 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 June 30, 2008, we have $175 million for the NEJD financing and $75.2 million for the Free State financing recorded as debt on our 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 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.

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Notes to Unaudited Condensed Consolidated Financial Statements

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 $100,000 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 pipelines to transport certain of our crude oil production to sales points where it is sold to third party purchasers. In the first six months of 2008 and 2007, we expensed $3.4 million and $2.7 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 June 30, 2008 and December 31, 2007, we had $4.9 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 June 30, 2008 and December 31, 2007, $26.3 million and $28.5 million, respectively, was recorded as deferred revenue, of which $4.1 million was included in current liabilities at both June 30, 2008 and December 31, 2007. We recognized deferred revenue of $1.1 million for each of the three months ended June 30, 2008 and 2007, and $2.2 million and $2.0 million during the six month periods ended June 30, 2008 and 2007, respectively, for deliveries under these volumetric production payments. We provide Genesis with certain processing and transportation services in connection with transporting CO_2 to their industrial customers for a fee of approximately $0.18 per Mcf of CO_2. For these services, we recognized revenues of $1.4 million and $1.2 million for the three month periods ended June 30, 2008 and 2007, respectively, and $2.6 million and $2.3 million for the six months ended June 30, 2008 and 2007, respectively.

Note 6. Derivative Instruments and Hedging Activities

Oil and 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.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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

Amounts in thousands	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Receipt (payment) on settlements of derivative contracts Oil	$ (12,131)	$ (1,108)	$ (19,523)	$ (981)
Receipt (payment) of settlements of derivative contracts Gas	(16,463)	2,827	(17,119)	10,951
Fair value adjustments to derivative contracts income (expense)	(30,223)	13,330	(68,956)	(21,828)
Commodity derivative income (expense)	$ (58,817)	$ 15,049	$ (105,598)	$ (11,858)

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

Crude Oil Contracts at June 30, 2008:

Type of Contract and Period	NYMEX Contract Prices Per Bbl: Bbls/d	NYMEX Contract Prices Per Bbl: Swap Price	Estimated Fair Value Liability at June 30, 2008 (In Thousands)
Swap Contracts			
July 2008 Dec. 2008	2,000	$ 57.34	$ (30,533)

Natural Gas Contracts at June 30, 2008:

Type of Contract and Period	NYMEX Contract Prices Per MMBtu: MMBtu/d	NYMEX Contract Prices Per MMBtu: Swap Price	Estimated Fair Value Liability at June 30, 2008 (In Thousands)
Swap Contracts			
July 2008 Dec. 2008	20,000	$ 7.89	$ (20,670)
July 2008 Dec. 2008	20,000	7.91	(20,596)
July 2008 Dec. 2008	20,000	7.94	(20,487)

At June 30, 2008, our oil and natural gas derivative contracts were recorded at their fair value, which was a net liability of $92.3 million.

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 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 (payment made to the counterparty in July 2008 in this amount). 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 $0.7 million (net of taxes of $0.4 million) in Accumulated Other Comprehensive Loss in our June 30, 2008 Unaudited Condensed Consolidating Balance Sheet. We recognized ineffectiveness totaling $0.1 million as expense in our Unaudited Condensed Consolidating Statement of Operations for the six months ended June 30, 2008.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

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 $6 million for tax years through 2007, and in the second quarter of 2008 has reduced its current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it 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:

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Balance Sheets

	June 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	$ 469,622	$ 449,986	$ 17,249	$ (491,899)	$ 444,958
Property and equipment		2,654,355	4,438		2,658,793
Investment in subsidiaries (equity method)	1,150,194		1,094,464	(2,244,658)	
Other assets	317,837	111,365	55,612	(315,451)	169,363
Total assets	$ 1,937,653	$ 3,215,706	$ 1,171,763	$ (3,052,008)	$ 3,273,114
Liabilities and Stockholders Equity					
Current liabilities	$ 12,342	$ 796,042	$ 21,537	$ (491,899)	$ 338,022
Long-term liabilities	300,643	1,325,200	32	(315,451)	1,310,424
Stockholders equity	1,624,668	1,094,464	1,150,194	(2,244,658)	1,624,668
Total liabilities and stockholders equity	$ 1,937,653	$ 3,215,706	$ 1,171,763	$ (3,052,008)	$ 3,273,114

	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 Reources 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 liabilties 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 June 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,625	$ 417,218	$ 767	$ (5,625)	$ 417,985
Expenses	5,746	233,361	828	(5,625)	234,310
Income (loss) before the following:	(121)	183,857	(61)		183,675
Equity in net earnings of subsidiaries	114,171		114,449	(228,620)	
Income before income taxes	114,050	183,857	114,388	(228,620)	183,675
Income tax provision (benefit)	(3)	69,408	217		69,622
Net income	$ 114,053	$ 114,449	$ 114,171	$ (228,620)	$ 114,053

	Three Months Ended June 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 5,531	$ 222,619	$ (109)	$ (5,531)	$ 222,510
Expenses	5,646	119,244	674	(5,531)	120,033
Income (loss) before the following:	(115)	103,375	(783)		102,477
Equity in net earnings of subsidiaries	62,676		63,372	(126,048)	
Income before income taxes	62,561	103,375	62,589	(126,048)	102,477
Income tax provision (benefit)	(6)	40,003	(87)		39,910
Net income	$ 62,567	$ 63,372	$ 62,676	$ (126,048)	$ 62,567

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Operations (continued)

	Six Months Ended June 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 11,250	$ 734,462	$ 858	$ (11,250)	$ 735,320
Expenses	11,491	433,883	1,632	(11,250)	435,756
Income (loss) before the following:	(241)	300,579	(774)		299,564
Equity in net earnings of subsidiaries	187,275		188,254	(375,529)	
Income before income taxes	187,034	300,579	187,480	(375,529)	299,564
Income tax provision (benefit)	(21)	112,325	205		112,509
Net income	$ 187,055	$ 188,254	$ 187,275	$ (375,529)	$ 187,055

	Six Months Ended June 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Revenues	$ 8,344	$ 396,611	$ 54	$ (8,344)	$ 396,665
Expenses	8,550	265,446	1,288	(8,344)	266,940
Income (loss) before the following:	(206)	131,165	(1,234)		129,725
Equity in net earnings of subsidiaries	79,379		80,570	(159,949)	
Income before income taxes	79,173	131,165	79,336	(159,949)	129,725
Income tax provision (benefit)	(10)	50,595	(43)		50,542
Net income	$ 79,183	$ 80,570	$ 79,379	$ (159,949)	$ 79,183

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2008				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ (10)	$ 370,325	$ 14	$	$ 370,329
Cash flow from investing activities	(23,757)	(384,797)	2,725	23,757	(382,072)
Cash flow from financing activities	23,757	98,645		(23,757)	98,645
Net increase (decrease) in cash	(10)	84,173	2,739		86,902
Cash, beginning of period	34	58,343	1,730		60,107
Cash, end of period	$ 24	$ 142,516	$ 4,469	$	$ 147,009

	Six Months Ended June 30, 2007				
Amounts in thousands	Denbury Resources Inc. (Parent & Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Other Guarantor Subsidiaries	Eliminations	Denbury Resources Inc. Consolidated
Cash flow from operations	$ 33	$ 195,195	$ 369	$	$ 195,597
Cash flow from investing activities	(170,258)	(421,019)		170,258	(421,019)
Cash flow from financing activities	170,258	204,126		(170,258)	204,126
Net increase (decrease) in cash	33	(21,698)	369		(21,296)
Cash, beginning of period	1	52,225	1,647		53,873
Cash, end of period	$ 34	$ 30,527	$ 2,016	$	$ 32,577

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, Alabama, and properties in Southeast Texas. Our primary goal is to increase the value of acquired properties through tertiary recovery operations, together with a combination of exploitation, drilling, and proven engineering extraction processes. 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 second quarter of 2008 our production averaged 46,305 BOE/d, a 25% increase over second quarter 2007 production after adjusting for the sale of our Louisiana natural gas properties in December 2007 and February 2008, and a 4% increase over production levels in the first quarter of 2008 (also adjusted for the Louisiana property sale). These increases were primarily from increases in our tertiary oil and Barnett Shale production. Commodity prices continued to increase during the second quarter of 2008, resulting in a 72% increase in our average per BOE price received in the second quarter of 2007, and a 28% increase over first quarter of 2008 average per BOE price received. As a result of the rising prices during the first half of 2008, we recognized non-cash fair value losses on our oil and natural gas derivative contracts of $38.7 million in the first quarter of 2008 and $30.2 million in the second quarter, and also made cash payments of $8.0 million and $28.6 million on our derivative contract settlements in the first and second quarters of 2008, respectively. This compares to a $21.8 million non-cash fair value charge on our derivative contracts in the first half of 2007 and net cash receipts of $10.0 million during that same period.

All of our expenses, other than interest expense, increased on both an absolute and per BOE basis during the second 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, which had lower operating costs per BOE, increased our operating cost per BOE by over $1.00, based on 2007 average costs. Interest expense decreased slightly in the 2008 periods as we capitalized more interest because of the significant expenditures made during 2007 and 2008 on unevaluated properties. The net result was net income of $114.1 million during the second quarter of 2008, a company quarterly record, as compared to $62.6 million of net income during the second quarter of 2007. On a six month basis, net income was $187.1 million during the first half of 2008 as compared to $79.2 million during the first half of 2007 as higher commodity prices and production in 2008 more than offset the higher expenses.

We continue to have a high rate of inflation in our industry, particularly for certain items such as steel products. Likewise, the availability of goods and services is mixed, with improvements in some areas such as rig availability, but still long lead times for certain items, such as compressors used in our tertiary recycle facilities and construction services for pipelines. There is also significant competition for technical and experienced personnel and overall compensation inflation in our industry appears to be much higher than the national average. It is difficult to forecast price trends and supply, service or personnel availability, which if adverse, would significantly impact both operating costs and capital expenditures, as well as cause delays in achieving our anticipated production targets and development goals.

Overview of tertiary operations. Since we acquired our first carbon dioxide tertiary flood in Mississippi in 1999, we have gradually increased our emphasis on these types of operations. We particularly like this play because of its risk profile, rate of return and lack of competition in our operating area. Generally, from East Texas to Florida, there are no known significant natural sources of carbon dioxide except our own, and these large volumes of CO_2 that we own drive the play. Please refer to the section entitled CO_2 Operations below and contained in Management s Discussion and

DENBURY RESOURCES INC.

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

Analysis of Financial Condition and Results of Operations in our 2007 Form 10-K for further information regarding these operations.

Oil production from our tertiary operations increased to an average of 18,661 BOE/d in the second quarter of 2008, a 36% increase over the second quarter 2007 tertiary production level of 13,683 BOE/d, and a 9% increase over the first quarter 2008 tertiary production level. As a result of our initial tertiary oil production from Tinsley Field (Phase III) in the second quarter of 2008, we recognized approximately 29.8 million barrels (MMBbls) of proved reserves at Tinsley Field, 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. For a further discussion, see Results of Operations CO_2 Operations .

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 line 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). The Company has capitalized these transactions for accounting purposes and currently projects that it 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 payments fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependant on the volumes of CO_2 transported therein.

Change in Tax Accounting Method for Certain Tertiary Costs. 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 $6 million for tax years through 2007, and in the second quarter of 2008 has reduced its current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. 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 portions of the tertiary facility equipment. Through June 30, 2008, we have 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.

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.

DENBURY RESOURCES INC.

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

Capital Resources and Liquidity

We have recently increased our current 2008 capital exploration and development budget by $100 million to approximately $1.0 billion, excluding any potential acquisitions, reflecting among other adjustments, the change in our operating lease program discussed above (see Overview Change in Tax Accounting Method for Certain Tertiary Costs). The current 2008 program includes an estimated $190 million to acquire pipe and right-of-ways for our proposed CO_2 pipeline from Louisiana to Texas (the Green Pipeline) and another $90 million for the segment of the Delta CO_2 Pipeline from Tinsley to Delhi Fields. We expect to spend an additional $500 million constructing the Green Pipeline during 2009, making our current anticipated total cost for that line approximately $700 million. Currently, over 75% of our 2008 budget is expected to be spent on tertiary related operations, approximately 15% in the Barnett Shale area, and the balance in other areas.

Last fall when we set our initial 2008 capital budget, it was forecasted to be significantly in excess of our projected cash flow from operations. However, with the significant increases in commodity prices since that time and based on oil and natural gas commodity prices as of late July 2008, we currently project that even with our increased capital budget, our 2008 cash flow should be sufficient to fund almost all of our current 2008 capital budget. With the recent influx of cash related to the two pipeline transactions with Genesis (see Overview Genesis Transactions), we currently have no bank debt and as of July 31, 2008, had approximately $150 million of excess cash on hand. While the recent change in our tax accounting (which will accelerate our tax deductions and result in lower current cash income taxes) has changed the economics of certain financing methods (see Overview Change in Tax Accounting Method for Certain Tertiary Costs) and will likely lead us to purchase rather than lease various equipment, thus requiring more capital, we do not anticipate requiring more than our bank credit line for our capital needs for the foreseeable future, except for the potential funding of acquisitions.

As part of our semi-annual bank review, our bank borrowing base was increased as of April 1, 2008 from $500 million to $1.0 billion as a result of our continued growth, along with the higher commodity prices. With regard to our bank credit facility, the borrowing base represents the amount that can be borrowed from a credit standpoint based on our assets, as confirmed by the banks, while our $350 million 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 ($350 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 July 31, 2008, we had outstanding $525 million (principal amount) of 7.5% subordinated notes and no bank debt.

We monitor our capital expenditures on a regular basis, adjusting them up or down depending on commodity prices and the resultant cash flow. Therefore, during the last few years as commodity prices have increased, we have increased our capital budget throughout the year. As a result of the recent cost inflation in our industry, many of our recent budget increases have related to escalating costs rather than additional projects. If costs do rise or we spend more than our estimated or forecasted amounts, we will either have to increase our capital budget or consider the elimination of a portion of our planned projects.

We also continue to pursue acquisitions of mature oil fields that we believe have potential as future tertiary flood candidates. These possible acquisitions are difficult to forecast and the purchase price can vary widely depending on the levels of existing production and conventional proved reserves and commodity prices. Because of the current high commodity price environment, the cost of acquiring fields whose primary and secondary reserves are largely depleted and only have minor amounts of current production can still be significant. Any acquisitions would be funded, at least temporarily, with bank or other debt, although if significant, the acquisition would likely be ultimately funded with more permanent capital such as subordinated debt and/or additional equity or the potential sale of other non-core assets.

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DENBURY RESOURCES INC.

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

Sources and Uses of Capital Resources

	Six Months Ended June 30,	
Amounts in thousands	2008	2007
Capital expenditures		
Oil and gas exploration and development		
Drilling	$ 129,187	$ 159,448
Geological, geophysical and acreage	9,475	10,558
Facilities	79,085	56,259
Recompletions	71,539	64,988
Capitalized interest	9,717	8,056
Total oil and gas exploration and development expenditures	299,003	299,309
Oil and gas property acquisitions	2,357	46,660
Total oil and natural gas capital expenditures	301,360	345,969
CO_2 capital expenditures, including capitalized interest	108,850	68,427
Total	$ 410,210	$ 414,396

Our first half 2008 capital expenditures were funded with $370.3 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 $195.6 million of cash flow from operations, $150.0 million from our issuance of subordinated debt in April of that year, $36.0 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 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 payments fixed at $20.7 million per year during the term of the financing lease, and the payments relating to the Free State Pipeline dependant 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 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 in the general area which aggregate 600 MMcf/d in order to justify the cost of a CO_2 pipeline to this area. 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 plants are built, the aggregate purchase obligation for CO_2 from our contracted potential synthetic sources could be up to $200 million per year, assuming a $130 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

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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 with whom 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.

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 2007 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 2008 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. During the second quarter of 2008 our CO_2 production averaged 596 MMcf/d, as compared to an average of approximately 477 MMcf/d during the second quarter of 2007. We used 86% of this production, or 510 MMcf/d, in our tertiary operations during the second quarter 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 18,661 BOE/d in the second quarter of 2008, a 36% increase over the second quarter 2007 tertiary production level of 13,683 BOE/d and a 9% increase over the first quarter 2008 tertiary production level. We saw our initial production from Tinsley Field (Phase III) in the second quarter of 2008, averaging 675 Bbls/d during the quarter. As a result of this production response to our CO_2 injections, we recognized approximately 29.8 MMBbls of proved reserves at Tinsley Field, 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. The majority of the remaining production increase came from our Phase II operations in eastern Mississippi (Soso, Eucutta and Martinville Fields) which contributed 3,304 BOE/d (approximately two-thirds) to the increase over the prior year s second quarter production, with the balance of the increase coming from our Phase I fields, except Little Creek Field which is on a gradual decline.

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	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
Phase I:						
Brookhaven	1,422	1,794	2,452	2,507	2,638	2,714
Little Creek area	2,117	1,974	2,011	1,957	1,807	1,661
Mallalieu area	5,470	5,802	5,823	6,304	6,099	6,260
McComb area	1,811	1,884	1,853	2,096	1,632	1,818
Phase II:						
Martinville	320	521	1,101	883	793	715
Eucutta	614	1,338	2,035	2,572	2,699	2,933
Soso	25	370	826	1,109	1,488	1,885
Phase III:						
Tinsley						675
Total tertiary oil production	11,779	13,683	16,101	17,428	17,156	18,661

We spent approximately $0.25 per Mcf to produce our CO_2 during the first half of 2008, a significant increase over the 2007 first six months average of $0.19 per Mcf, primarily due to increased CO_2 royalty expense due to higher oil prices (upon which royalties are based) in the first half of 2008. Our estimated total cost per thousand cubic feet of CO_2 during the first half of 2008 was approximately $0.33, after inclusion of depreciation and amortization expense, up from the 2007 average of $0.27 per Mcf. On a quarterly basis, we spent approximately $0.27 per Mcf to produce our CO_2 during the second quarter of 2008, also a significant increase from the 2007 second quarter average of $0.21 per Mcf, the increase primarily attributable to the same increase in oil prices. Our estimated total cost per thousand cubic feet of CO_2 during the second 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. 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. Operating costs per BOE on our tertiary operations averaged $20.27, $20.47 and $20.38 during the first and second quarters and first half of 2007, respectively, and averaged $20.81, $24.67 and $22.82 during the first and second quarters and first half of 2008, respectively.

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 second quarter of 2008, we would have expensed an additional $1.4 million or $0.85 per BOE (tertiary properties only) had we following our prior year s accounting methodology. During the first half of 2007, the accounting methodology was not material, as only $0.6 million would have been capitalized under the new accounting procedure.

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Operating Results

As summarized in the Overview section above and discussed in more detail below, for the second quarter of 2008, higher commodity prices and higher production more than offset higher expenses and unfavorable non-cash mark-to-market value adjustments to income, resulting in record quarterly earnings and cash flow from operations. On a six month basis, the same trends applied, resulting in significant increases in our operating results.

	Three Months Ended June 30,		Six Months Ended June 30,	
Amounts in thousands, except per share amounts	2008	2007	2008	2007
Net income	$114,053	$ 62,567	$187,055	$ 79,183
Net income per common share basic	0.47	0.26	0.77	0.33
Net income per common share diluted	0.45	0.25	0.74	0.32
Cash flow from operations	164,072	102,252	370,329	195,597

Certain of our operating results and statistics for the comparative second quarters and first six months of 2008 and 2007 are included in the following table.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Average daily production volumes				
Bbls/d	31,332	26,172	30,748	25,119
Mcf/d	89,835	94,459	89,127	90,007
BOE/d (1)	46,305	41,916	45,602	40,120
Operating revenues (in thousands)				
Oil sales	$ 326,962	$ 151,178	$ 577,403	$ 269,310
Natural gas sales	86,281	66,301	149,037	117,303
Total oil and natural gas sales	$ 413,243	$ 217,479	$ 726,440	$ 386,613
Oil and gas derivative contracts (2) (in thousands)				
Cash receipt (payment) on settlement of derivative contracts	$ (28,594)	$ 1,719	$ (36,642)	$ 9,970
Non-cash fair value adjustment income (expense)	(30,223)	13,330	(68,956)	(21,828)
Total income (expense) from oil and gas derivative contracts	$ (58,817)	$ 15,049	$ (105,598)	$ (11,858)
Operating expenses (in thousands)				
Lease operating expenses	$ 76,825	$ 57,207	$ 142,826	$ 107,764
Production taxes and marketing expenses (3)	20,530	10,386	37,266	20,590
Total production expenses	$ 97,355	$ 67,593	$ 180,092	$ 128,354
Non-tertiary CO_2 operating margin (in thousands)				
CO_2 sales and transportation fees (4)	$ 3,383	$ 3,394	$ 6,234	$ 6,485
CO_2 operating expenses	(453)	(1,204)	(1,596)	(1,907)
Non-tertiary CO_2 operating margin	$ 2,930	$ 2,190	$ 4,638	$ 4,578
Unit prices including impact of derivative settlements (2)				
Oil price per Bbl	$ 110.42	$ 63.01	$ 99.69	$ 59.02
Gas price per Mcf	8.54	8.04	8.13	7.87
Unit prices excluding impact of derivative settlements (2)				

Oil price per Bbl	$ 114.67	$ 63.48	$ 103.18	$ 59.23
Gas price per Mcf	10.55	7.71	9.19	7.20
Oil and gas operating revenues and expenses per BOE (1)				
Oil and natural gas revenues	$ 98.07	$ 57.02	$ 87.53	$ 53.24
Oil and gas lease operating expenses	$ 18.23	$ 15.00	$ 17.21	$ 14.84
Oil and gas production taxes and marketing expense	4.87	2.72	4.49	2.84
Total oil and gas production expenses	$ 23.10	$ 17.72	$ 21.70	$ 17.68

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

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

(3) Includes Transportation expense Genesis.

(4) Includes deferred revenue of $1.1 million for each of the three month periods ended June 30, 2008 and 2007, and $2.2 million and $2.0 million for the six month periods ended June 30, 2008 and 2007, respectively,

associated with volumetric production payments with Genesis. Also includes transportation income from Genesis of $1.4 million and $1.2 million for each of the three month periods ended June 30, 2008 and 2007, respectively, and $2.6 million and $2.3 million for the six months ended June 30, 2008 and 2007, respectively.

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Production: Production by area for each of the quarters of 2007 and the first and second 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
Mississippi CO_2 floods	11,779	13,683	16,101	17,428	17,156	18,661
Mississippi non CO_2 floods	12,738	12,525	12,131	12,530	12,128	11,617
Texas	6,989	9,048	10,695	13,488	13,522	14,068
Onshore Louisiana	5,591	5,391	5,546	5,638	905	663
Alabama and other	1,208	1,269	1,247	1,287	1,189	1,296
Total Company	38,305	41,916	45,720	50,371	44,900	46,305

As outlined in the above table, production in the second quarter of 2008 (after adjusting for the sale of our Louisiana natural gas properties in December 2007 and February 2008 see Overview Sale of Louisiana Natural Gas Assets) increased 25% (9,110 BOE/d) over second quarter of 2007 levels, 4% over the first quarter 2008 levels, and 29% in the first six months of 2008 compared to production in the first six months of 2007. The production increase between the first and second quarters of 2008 was primarily due to increased production from our tertiary operations, coupled with production increases in the Barnett Shale that increased both year-to-year and quarter-to-quarter. 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 was up only slightly in the second quarter of 2008 from the most recent prior two quarters, averaging 13,434 BOE/d in the second quarter of 2008, 12,801 BOE/d during the first quarter of 2008 and 12,729 BOE/d during the fourth quarter of 2007, although production in all three quarters is significantly higher than production rates a year ago. The Texas property acquisition we made late in the first quarter of 2007 contributed approximately 634 BOE/d to the second quarter 2008 production.

Oil and Natural Gas Revenues: Oil and natural gas revenues for the second quarter of 2008 increased $195.8 million, or 90%, from revenues in the comparable quarter of 2007, as both commodity prices and production were higher. The increase in overall commodity prices in the second quarter of 2008 increased revenues by $173.0 million, or 80%, while the increase in production in the second quarter of 2008 increased oil and natural gas revenues by $22.8 million, or 10%, over the prior year s second quarter levels. When comparing the respective six month periods, revenues increased $339.8 million, or 88%, for the same reasons. The increase in overall commodity prices during the first half of 2008 increased oil and natural gas revenues by $284.6 million, or 74% over those revenues in the prior year s first half, while the increase in production during the first half of 2008 increased revenues by $55.2 million, or 14%.

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

	Three Months Ended March 31,			Three Months Ended June 30,			Six Months Ended June 30,		
	2008	2007	% Change	2008	2007	% Change	2008	2007	% Change
Net Realized Prices:									
Oil price per Bbl	$91.24	$54.57	67%	$114.67	$63.48	81%	$103.18	$59.23	74%
Gas price per Mcf	7.80	6.63	18%	10.55	7.71	37%	9.19	7.20	28%
Price per BOE	76.65	49.06	56%	98.07	57.02	72%	87.53	53.24	64%
NYMEX differentials:									
Oil per Bbl	$ (6.50)	$ (3.73)	74%	$ (9.64)	$ (1.61)	>100%	$ (7.85)	$ (2.47)	>100%
Natural Gas per Mcf	(0.90)	(0.51)	76%	(0.93)	0.07	>100%	(0.91)	(0.19)	>100%

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.

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. The sale of our Louisiana natural gas properties also contributed to a higher or worse differential during the first quarter of 2008, as we typically received higher than NYMEX prices for the natural gas produced from these sold properties.

Oil and Natural Gas Derivative Contracts: We made cash payments of $28.6 million on settlements of our oil and natural gas derivative contracts during the second quarter of 2008, as compared to net cash receipts of $1.7 million during the second quarter of 2007, a negative differential of $30.3 million. Approximately 42% of the payments made during the second 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 to the natural gas swaps for 2008. On a six month basis, we made cash payments of $36.6 million on settlements of our oil and natural gas derivative contracts during the first half of 2008, as compared to net cash receipts of $10.0 million during the first half of 2007, a negative differential of $46.6 million. Approximately 53% of the payments made during the first half 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 expense was $30.2 million during the second quarter of 2008, as compared to mark-to-market income of $13.3 million during the second quarter of 2007. On a six month basis, our total mark-to-market expense was $69.0 million during the first half of 2008, as compared to mark-to-market expense of $21.8 million during the first half of 2007. During the 2008 periods, both oil and natural gas prices increased during the periods, causing large mark-to-market value charges. However, during the first half of 2007, natural gas prices fluctuated, causing mark-to-market value income during the first quarter of 2007, but a significant charge during the second quarter of that year. Because we do not utilize hedge accounting for our commodity derivative contracts, the adjustments in the fair value of these contracts is 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 six months and second 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 over 50% of our total operating expenses during the second quarter of 2008. Other factors such as higher overall industry costs and increased personnel and related costs also contributed to higher expenses.

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During the second quarter of 2008, operating costs averaged $18.23 per BOE, up from $15.00 per BOE in the second quarter of 2007, and up from the $16.15 per BOE in the first quarter of 2008. The trends were similar when comparing the respective first half periods. A significant portion of the increase in per BOE expenses in the second quarter of 2008 resulted from the sale of our Louisiana natural gas properties. If the sold properties were excluded from the second quarter of 2007 results, our operating costs during that period would have been approximately $1.17 per BOE higher than reported, or $16.17 per BOE, more in line with the second quarter of 2008 operating costs per BOE.

Production taxes and marketing expenses generally change in proportion to commodity prices and production volumes and therefore were higher in the second quarter of 2008 than in the comparable quarter of 2007. Transportation and plant processing fees were approximately $3.0 million higher in the second quarter of 2008 than in the second quarter of 2007 and approximately $4.7 million higher for the first half of 2008 than in the first half of 2007.

General and Administrative Expenses

Net general and administrative (G&A) expenses increased 27% between the respective second quarters and 33% between the respective first six months, as set forth below:

	Three Months Ended June 30,		Six Months Ended June 30,	
Amounts in thousands, except per BOE data and employees	2008	2007	2008	2007
Net G&A expense (thousands)				
Gross G&A expenses	$ 33,871	$ 28,372	$ 68,036	$ 55,142
State franchise taxes	857	740	1,685	1,458
Operator labor and overhead recovery charges	(16,808)	(14,894)	(32,761)	(28,700)
Capitalized exploration and development costs	(3,109)	(2,524)	(6,144)	(4,772)
Net G&A expense	$ 14,811	$ 11,694	$ 30,816	$ 23,128
Average G&A cost per BOE	$ 3.51	$ 3.07	$ 3.71	$ 3.18
Employees as of June 30	761	672	761	672

Gross G&A expenses increased $5.5 million, or 19%, between the respective second quarters and $12.9 million, or 23%, between the respective first six months. Approximately $5.4 million of the increase in gross G&A expenses between the respective quarters is related to increases in compensation and personnel related costs (approximately $12.5 million between the respective first six 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 11% during the first half of 2008. Stock compensation expense reflected in gross G&A expenses was approximately $4.0 million for the second quarter of 2008 and $3.0 million for the second quarter of 2007. On a six month basis, stock compensation was approximately $8.5 million for the first half of 2008 and $6.1 million for the first half of 2007. Due to increased competitive pressures in the industry, our wages are 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 second quarter and first six 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 13% between the second quarters of 2007 and 2008 and increased by 14% between the first six months of 2007 and 2008. Capitalized exploration costs also increased by 23% between the second quarters of 2007 and 2008 and increased by 29% between the first six months of 2007 and 2008, primarily as a result of increases in personnel and compensation costs.

The net effect was a 27% increase in net G&A expense between the respective second quarters and a 33% increase between the first six months of 2008 and 2007. On a per BOE basis, G&A costs also increased although at a lower percentage as a result of the higher production, increasing 14% in the second quarter of 2008 as compared to levels in the second quarter of 2007, and 17% between the comparative first six months of 2008 and 2007.

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Interest and Financing Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
Amounts in thousands, except per BOE data and interest rates	2008	2007	2008	2007
Cash interest expense	$ 13,278	$ 12,162	$ 25,078	$ 21,792
Non-cash interest expense	408	515	815	993
Less: Capitalized interest	(5,545)	(4,321)	(12,811)	(8,354)
Interest expense	$ 8,141	$ 8,356	$ 13,082	$ 14,431
Interest and other income	$ 1,359	$ 1,637	$ 2,646	$ 3,567
Net cash interest expense and other income per BOE (1)	$ 1.79	$ 1.65	$ 1.34	$ 1.43
Average debt outstanding	$ 698,475	$ 653,303	$ 680,142	$ 592,284
Average interest rate (2)	7.6%	7.4%	7.4%	7.4%

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

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

Interest expense decreased $0.2 million, or 3%, comparing the second quarters of 2007 and 2008, and $1.3 million, or 9%, comparing levels in the first halves of 2007 and 2008, primarily as a result of higher capitalized interest during the 2008 periods. Our interest capitalization increased in 2008 because of our growing balance of unevaluated property expenditures related to our CO_2 tertiary floods without proved reserves, the largest of which was Tinsley Field, and the construction of our new CO_2 pipelines. Net interest expense increased in the second quarter of 2008 as compared to the first quarter of 2008 as we discontinued the capitalization of interest at Tinsley Field after production commenced there in April 2008. The increase in capitalized interest was partially offset by a 7% increase in our average debt level between the two quarters and a 15% increase between the respective first six months. On May 30, 2008, we closed on two transactions with Genesis (see Overview Genesis Transactions), with cash proceeds of $225 million which was used to retire our bank debt. However, since we are accounting for the obligations to Genesis as financing leases, the transaction will increase our future interest expense as the implied interest rate is higher for the Genesis financing leases than for our other outstanding debt.

Depletion, Depreciation and Amortization

	Three Months Ended	Six Months Ended

Amounts in thousands, except per BOE data	June 30, 2008	June 30, 2007	June 30, 2008	June 30, 2007
Depletion and depreciation of oil and natural gas properties	$ 47,820	$ 40,977	$ 92,010	$ 76,943
Depletion and depreciation of CO_2 assets	3,604	2,762	6,626	5,442
Asset retirement obligations	762	756	1,524	1,486
Depreciation of other fixed assets	2,547	1,740	4,412	3,391
Total DD&A	$ 54,733	$ 46,235	$ 104,572	$ 87,262
DD&A per BOE:				
Oil and natural gas properties	$ 11.53	$ 10.94	$ 11.27	$ 10.80
CO_2 assets and other fixed assets	1.46	1.18	1.33	1.22
Total DD&A cost per BOE	$ 12.99	$ 12.12	$ 12.60	$ 12.02

Our depletion, depreciation and amortization (DD&A) rate for oil and natural gas properties on a per BOE basis increased 5% between the respective second quarters and increased 4% between the respective first six months, primarily due to capital spending and increased costs. In the second quarter of 2008, we booked approximately 29.8 million barrels

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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. Correspondingly, we 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 average DD&A rate. We do 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, we also moved approximately $37 million of equipment costs into our depletion calculation due to our decision to abandon our operating lease program due to 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 quarter 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 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 the second quarter of 2008 as compared to the rate in the comparable quarter in 2007, primarily as a result of expenditures related to the expansion of our corporate office space. Commencing January 1, 2008, we began capitalizing costs incurred to inject CO_2 into fields that were in the development stage and had not yet shown a production response to the CO_2 (see Results of Operations CO_2 Operations).

Income Taxes

Amounts in thousands, except per BOE amounts and tax rates	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Current income tax expense	$ 10,844	$ 7,343	$ 32,080	$ 8,961
Deferred income tax expense	58,778	32,567	80,429	41,581
Total income tax expense	$ 69,622	$ 39,910	$ 112,509	$ 50,542
Average income tax expense per BOE	$ 16.52	$ 10.46	$ 13.56	$ 6.96
Effective tax rate	37.9%	38.9%	37.6%	39.0%

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 first six 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 $6 million for tax years through 2007, and in the second quarter of 2008 has reduced its current income tax expense by approximately $19 million to adjust for the impact of this change through the first six months of 2008. The reduction in current income tax expense has been offset by a corresponding increase in deferred income tax expense of approximately the same amount. Although this change is not expected to have a significant impact on the Company s overall tax rate, it is anticipated that it will reduce the amount of cash taxes the Company expects to pay over the next several years.

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Per BOE Data

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Per BOE data	2008	2007	2008	2007
Oil and natural gas revenues	$ 98.07	$ 57.02	$ 87.53	$ 53.24
Gain (loss) on settlements of derivative contracts	(6.79)	0.45	(4.42)	1.37
Lease operating expenses	(18.23)	(15.00)	(17.21)	(14.84)
Production taxes and marketing expenses	(4.87)	(2.72)	(4.49)	(2.84)
Production netback	68.18	39.75	61.41	36.93
Non-tertiary CO_2 operating margin	0.70	0.57	0.56	0.63
General and administrative expenses	(3.51)	(3.07)	(3.71)	(3.18)
Net cash interest expense and other income	(1.79)	(1.65)	(1.34)	(1.43)
Current income taxes and other	(2.08)	(1.39)	(3.20)	(0.62)
Changes in assets and liabilities relating to operations	(22.56)	(7.40)	(9.10)	(5.39)
Cash flow from operations	38.94	26.81	44.62	26.94
DD&A	(12.99)	(12.12)	(12.60)	(12.02)
Deferred income taxes	(13.95)	(8.54)	(9.69)	(5.73)
Non-cash commodity derivative adjustments	(7.17)	3.49	(8.31)	(3.01)
Changes in assets and liabilities and other non-cash items	22.24	6.76	8.52	4.72
Net income	$ 27.07	$ 16.40	$ 22.54	$ 10.90

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 June 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. The following table presents the carrying and fair values of our debt as of June 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	$	$224,077	$224,438
7.5% subordinated debt due 2015 (fixed rate of 7.5%)		300,000	300,642	298,500

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 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. We did

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make an exception in late 2006 when we swapped 80% to 90% of our forecasted 2007 natural gas production at a weighted average price of $7.96 per Mcf, and in September 2007 when 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. As a result of the higher oil and natural gas prices, we currently anticipate that our cash flow will exceed our current capital budget (see Capital Resources and Liquidity).

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 June 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 related to the acquisition represent less than 10% of our estimated 2008 production, are intended to help protect our acquisition economics related to the first three years of production of the proved producing reserves that we acquired, and cover 2,000 Bbls/d for 2008 at a price of $57.34 per Bbl.

At June 30, 2008, our derivative contracts were recorded at their fair value, which was a liability of approximately $92.3 million, an increase in liability of approximately $69.0 million from the $23.3 million fair value liability recorded as of December 31, 2007. This change is the result of the increases in both oil and natural gas commodity futures prices between December 31, 2007 and June 30, 2008.

Based on NYMEX crude oil futures prices at June 30, 2008, we would expect to make future cash payments of $30.8 million on our oil commodity hedges. If oil futures prices were to decline by 10%, the amount we would expect to pay under our oil commodity hedges would decrease to $25.6 million, and if futures prices were to increase by 10% we would expect to pay $36.0 million. Based on NYMEX natural gas futures prices at June 30, 2008, we would expect to make a future cash payments of $61.9 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, we would expect to make future cash payments of $46.9 million, and if futures prices were to increase by 10% we would expect to pay $76.8 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, asset retirement obligations, income taxes 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.

Forward-Looking Information

The statements contained in this Quarterly Report on Form 10-Q that are not historical facts, including, but not limited to, statements found in this Management s Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements, as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, cost savings, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon or expected reserve quantities and values, potential reserves from tertiary operations, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as plan, estimate, expect, predict, anticipate, projected, should, assume, believe, target 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

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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.

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 June 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.

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 1.A. Risk Factors

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

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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
April 1 through 30, 2008		$		
May 1 through 31, 2008	355	30.79		
June 1 through 30, 2008	780	36.47		
Total	1,135	34.70		

Item 3. Defaults Upon Senior Securities

None.

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

Denbury s Annual Meeting of Stockholders was held on May 15, 2008 for the purposes of (1) electing eight directors, each to serve until their successor is elected and qualified and (2) to ratify the appointment by the audit committee of PricewaterhouseCoopers LLP as the Company s independent registered accountants for 2008. Holders of 225,343,588 shares of common stock, representing approximately 92% of the total issued and outstanding shares of common stock were present in person or by proxy at the meeting to cast their vote.

With respect to the election of directors, all eight nominees were elected. All of the directors are elected on an annual basis. The votes were cast as follows:

Nominees for Directors	For	Withheld
Ronald G. Greene	202,126,942	4,216,646
Michael L. Beatty	224,513,979	829,609
Michael B. Decker	224,892,780	450,808
David I. Heather	224,815,496	528,092
Greg McMichael	224,815,085	825,503
Gareth Roberts	223,083,441	2,260,147
Randy Stein	224,430,811	912,777
Wieland F. Wettstein	221,473,380	3,870,208

The appointment by the audit committee of PricewaterhouseCoopers LLP as the Company s independent auditor for 2008 was approved. The votes were cast as follows:

For	Against	Abstentions	Broker Non-Votes
224,628,098	128,567	586,923	-0-

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibits:

10(a)	Pipeline Financing Lease Agreement between Genesis NEJD Pipeline, LLC, as Lessor, and Denbury Onshore, LLC, as Lessee, dated May 30, 2008 (incorporated by reference as Exhibit 99.1 of our Form 8-K filed June 5, 2008).
10(b)	Transportation Services Agreement between Genesis Free State Pipeline, LLC, and Denbury Onshore, LLC, dated May 30, 2008 (incorporated by reference as Exhibit 99.2 of our Form 8-K filed June 5, 2008).
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.

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SIGNATURES

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

DENBURY RESOURCES INC.
(Registrant)

By: /s/ Phil Rykhoek
Phil Rykhoek
Sr. Vice President and Chief Financial Officer

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

Date: August 7, 2008