DENBURY RESOURCES INC
Form 10-Q
November 08, 2005

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

FORM 10-Q

(Mark One)

[X] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2005

[ ] 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 3000 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 [X] No [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes [X] No [ ]

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

Class	Outstanding at October 31, 2005
Common Stock, $.001 par value	114,564,508

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except shares)

	September 30, 2005	December 31, 2004
Assets		
Current assets		
Cash and cash equivalents	$ 36,990	$ 33,039
Short-term investments	-	57,171
Accrued production receivables	55,567	44,790
Related party receivable - Genesis	1,062	745
Trade and other receivables	14,189	10,963
Deferred tax asset	35,421	25,189
Derivative assets	-	949
Total current assets	143,229	172,846
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	1,584,092	1,326,401
Unevaluated	49,187	20,253
CO2 properties and equipment	180,619	132,685
Other	32,361	25,929
Less accumulated depletion and depreciation	(776,773)	(707,906)
Net property and equipment	1,069,486	797,362
Investment in Genesis	6,669	6,791
Other assets	10,791	15,707
Total assets	$ 1,230,175	$ 992,706
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 70,316	$ 49,429
Current deferred revenue and other - Genesis	2,432	2,431
Oil and gas production payable	30,108	24,856
Derivative liabilities	11,390	5,815
Short-term capital lease obligations - Genesis	560	375
Total current liabilities	114,806	82,906
Long-term liabilities		
Capital lease obligations - Genesis	6,018	4,184
Long-term debt	243,543	223,397
Asset retirement obligations	24,078	18,944
Deferred revenue - Genesis	21,404	23,378
Deferred tax liability	145,823	97,125
Other	2,222	1,100
Total long-term liabilities	443,088	368,128
Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	-	-

Common stock, $.001 par value, 250,000,000 shares authorized; 114,927,186 and 56,607,877 shares issued at September 30, 2005 and December 31, 2004, respectively	115	57
Paid-in capital in excess of par	459,821	441,023
Deferred compensation	(18,860)	(21,678)
Retained earnings	238,389	129,104
Accumulated other comprehensive loss	(1,384)	(4,788)
Treasury stock, at cost, 371,694 and 93,072 shares at September 30, 2005 and December 31, 2004, respectively	(5,800)	(2,046)
Total stockholders' equity	672,281	541,672
Total liabilities and stockholders' equity	$ 1,230,175	$ 992,706

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months Ended September 30,		
	2005	2004	
Revenues and other income			
Oil, natural gas and related product sales			
Unrelated parties	$ 137,137	$ 82,502	$
Related party - Genesis	1,411	20,566	
CO2 sales and transportation fees			
Unrelated parties	1,119	307	
Related party - Genesis	1,475	1,374	
Loss on effective hedge contracts	-	(17,465)	
Interest income and other	716	701	
Total revenues and other income	141,858	87,985	
Expenses			
Lease operating expenses	25,983	19,781	
Production taxes and marketing expenses	5,995	4,634	
Transportation expense - Genesis	1,023	266	
CO2 operating expenses	631	255	
General and administrative expenses	8,952	6,197	
Interest, net of amounts capitalized of $415, none, $1,049 and none, respectively	4,507	4,768	
Depletion and depreciation	24,340	20,780	
Commodity derivative expense	11,818	5,161	
Total expenses	83,249	61,842	
Equity in net income (loss) of Genesis	(55)	(37)	

Income before income taxes	58,554	26,106	
Income tax provision (benefit)			
Current income taxes	7,684	18,949	
Deferred income taxes	12,324	(11,117)	
Net income	$ 38,546	$ 18,274	$
Net income per common share - basic	$ 0.34	$ 0.17	$
Net income per common share - diluted	$ 0.32	$ 0.16	$
Weighted average common shares outstanding			
Basic	112,159	110,170	
Diluted	119,487	115,098	

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements)

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

	Three Months End September 30,	
	2005	2
Cash flow from operating activities:		
Net income	$ 38,546	$
Adjustments needed to reconcile to net cash flow provided by operations:		
Depreciation and depletion	24,340	
Non-cash hedging adjustments	8,054	
Deferred income taxes	12,324	(
Deferred revenue - Genesis	(682)	
Deferred compensation - restricted stock	1,031	
Current income tax benefit from stock options	3,242	
Amortization of debt issue costs and other	491	
Changes in assets and liabilities:		
Accrued production receivable	(3,700)	
Trade and other receivables	5,284	
Derivative assets and liabilities	-	
Other assets	-	
Accounts payable and accrued liabilities	(13,546)	
Oil and gas production payable	955	
Other liabilities	(52)	
Net cash provided by operations	76,287	
Cash flow used for investing activities:		
Oil and natural gas expenditures	(72,020)	(
Acquisitions of oil and gas properties	(2,700)	
Increase in accrual for capital expenditures	10,878	
Acquisitions of CO2 assets and capital expenditures	(14,751)	(

Net proceeds from CO2 production payment - Genesis	-	
Sale of Denbury Offshore, Inc.	-	1
Purchases of other assets	(1,057)	
Proceeds from property sales	1,888	
Deposits on oil and gas property acquisitions	-	
Purchases of short-term investments	-	(
Sales of short-term investments	2,000	
Increase in restricted cash	(78)	
Net cash provided by (used by) investing activities	(75,840)	1
Cash flow from financing activities:		
Bank repayments	-	(
Bank borrowings	10,000	
Payments on capital lease obligations - Genesis	(132)	
Issuance of common stock	3,314	
Purchase of treasury stock	(1,955)	
Costs of debt financing	-	
Net cash provided by (used by) financing activities	11,227	(
Net increase in cash and cash equivalents	11,674	
Cash and cash equivalents at beginning of period	25,316	
Cash and cash equivalents at end of period	$ 36,990	$
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest	$ 374	$
Cash paid during the period for income taxes	1,500	

(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements

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

	Three Months Ended September 30,	
	2005	2004
Net income	$ 38,546	$ 18
Other comprehensive income (loss), net of income tax:		
Change in fair value of derivative contracts, net of tax of $(8,916) and $(21,586), respectively	-	(14
Reclassification adjustments related to settlements of derivative contracts, net of tax of $713, $9,704, $2,072, and $25,474, respectively	1,163	15
Unrealized gain (loss) on securities available for sale	-	
Comprehensive income	$ 39,709	$ 19

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(See accompanying Notes to Unaudited Condensed Consolidated Financial Statements

DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 "Company" 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, 2004. Any capitalized terms used but not defined in these Notes to Unaudited Condensed Consolidated Financial Statements have the same meaning given to them in the Form 10-K.

Accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results of operations for the interim periods shown in this report are not necessarily indicative of results to be expected for the fiscal year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments (of a normal recurring nature) necessary to present fairly the consolidated financial position of Denbury as of September 30, 2005 and the consolidated results of its operations and cash flows for the three and nine month periods ended September 30, 2005 and 2004. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

Stock Split

On October 19, 2005, 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 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, 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 and any other convertible securities outstanding. For the three and nine month periods ended September 30, 2005 and 2004, there were no adjustments to net income for purposes of calculating diluted net income per common share. The following is a reconciliation of the weighted average common shares used in the basic and diluted net income per common share calculations for the three and nine month periods ended September 30, 2005 and 2004.

	Three Months Ended September 30,		Nine Months September
(Shares in Thousands)	2005	2004	2005
Weighted average common shares - basic.....	112,159	110,170	111,466
Potentially dilutive securities:			
Stock options.....	6,264	4,868	6,691
Restricted stock.....	1,064	60	941
Weighted average common shares - diluted.....	119,487	115,098	119,098

The weighted average common shares - basic amount in 2005 excludes 2,018,000 shares of non-vested restricted stock granted in 2005 and 2004 that is subject to future time vesting requirements. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic net income per common share. For purposes of calculating weighted average common shares - diluted, the non-vested restricted stock is included in the computation using the treasury stock method, with the proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future

tax consequences recognized directly in equity. The restricted shares were issued in August 2004 through January 2005 and have been included in the calculation for the periods they were outstanding. These shares may result in greater dilution in future periods, depending on the market price of our common stock during those periods.

For the three months ended September 30, 2005 and 2004, stock options to purchase approximately 131,000 and 64,000 shares of common stock, and for the nine months ended September 30, 2005 and 2004, stock options to purchase approximately 304,000 and 126,000 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.

Stock-based Compensation

We issue stock options to all of our employees under our stock option plans and we have issued restricted stock to our officers and directors. We account for this stock-based compensation utilizing the recognition and measurement principles of Accounting Principles Board Opinion 25, "Accounting for Stock Issued to Employees," and its related interpretations. Under these principles no stock-based employee compensation expense for stock options is reflected in net income as long as the stock options have an exercise price equal to the price of the underlying common stock on the date of grant. We recognize compensation expense for restricted stock over the applicable vesting periods. The following table illustrates the effect on net income and net income per common share as if we had applied the fair value recognition and measurement provisions of Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, in accounting for our stock options.

	Three Months Ended September 30,		Nin
	2005	2004	20
Net income: (thousands)			
Net income, as reported	$ 38,546	$ 18,274	$ 1
Add: stock-based compensation included in reported net income, net of related tax effects	679	368	
Less: stock-based compensation expense applying fair value based method, net of related tax effects	2,152	1,155	
Pro-forma net income	$ 37,073	$ 17,487	$ 1
Net income per common share			
As reported:			
Basic	$ 0.34	$ 0.17	$
Diluted	0.32	0.16	
Pro forma:			
Basic	$ 0.33	$ 0.16	$
Diluted	0.31	0.15	

Derivative Instruments and Hedging Activities

Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts. See Note 5 for further discussion regarding this change.

Short-term Investments

During the first nine months of 2005, we sold all of our available-for-sale securities.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values. Pro forma disclosure is no longer an alternative.

SFAS No. 123(R) must be adopted at the beginning of our next fiscal year (i.e., January 1, 2006) and permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized based on the requirements of SFAS No. 123(R) for all share-based payments granted prior to the effective date of SFAS No. 123(R) that remain unvested on the adoption date.

- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

As permitted by SFAS No. 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, we generally do not recognize compensation expense associated with employee stock options. Accordingly, the adoption of SFAS No. 123(R)'s fair value method could have a significant impact on Denbury's future results of operations, although it will have no impact on our overall financial position. We currently plan to adopt the provisions of SFAS No. 123(R) on January 1, 2006 using the modified prospective approach. We have not completed evaluating the impact the adoption of SFAS No. 123(R) will have on our future results of operations.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future; however, it will not have an impact on the Company's overall cash flows.

2. ASSET RETIREMENT OBLIGATIONS

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

DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the changes in our asset retirement obligations for the nine months ended September 30, 2005.

	Nine Months Ended September 30, 2005
	(in thousands)
Beginning asset retirement obligation, as of 12/31/2004....	$ 21,540
Liabilities incurred during period.....	2,035
Revisions in estimated cash flows.....	981
Liabilities settled during period.....	(442)
Accretion expense.....	1,279
Ending asset retirement obligation, as of 9/30/2005.....	$ 25,393

At September 30, 2005, $1.3 million of our asset retirement obligation was classified in "Accounts payable and accrued liabilities" under current liabilities in our Condensed Consolidated Balance Sheets. 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 $6.6 million at September 30, 2005, and $6.4 million at December 31, 2004 and are included in "Other assets" in our Condensed Consolidated Balance Sheets.

3. STOCK REPURCHASE PLAN

Between August 2003 and June 30, 2005, Denbury had an active stock repurchase plan ("Plan") to purchase shares of our common stock on the NYSE in order for such repurchased shares to be reissued to our employees who participate in Denbury's Employee Stock Purchase Plan ("ESPP"). The Plan provided for purchases through an independent broker of 100,000 shares of Denbury's common stock per fiscal quarter over a period of approximately twelve months, or a total of 400,000 shares per year. Purchases were made at prices and times determined at the discretion of the independent broker, provided however that no purchases may be made during the last ten business days of a fiscal quarter. In 2004, we repurchased into treasury 400,000 shares at an average cost of $9.95 per share and reissued 230,180 treasury shares under the ESPP. In the first six months of 2005, we repurchased into treasury 200,000 shares at an average cost of $15.82 per share and reissued 99,024 treasury shares under the ESPP. The repurchase plan expired as of June 30, 2005 and the Board of Directors currently does not plan to renew the Plan until a significant portion of the treasury shares have been used under our ESPP.

4. RELATED PARTY TRANSACTIONS - GENESIS

Interest in and Transactions with Genesis

Denbury is the general partner and owns an aggregate 9.25% interest in Genesis Energy, L.P. ("Genesis"), a publicly traded master limited partnership. Genesis has three primary lines of business: crude oil gathering and marketing,

pipeline transportation, primarily in Mississippi, Texas, Alabama and Florida, and wholesale marketing of carbon dioxide.

We are accounting for our 9.25% 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 equity in Genesis' net income (loss) for the three months ended September 30, 2005 and 2004 was $(55,000) and $(37,000), and for the nine months ended September 30, 2005 and 2004 was $276,000 and $(28,000), respectively. Genesis Energy, Inc., the general partner of which we own 100%, has guaranteed the bank debt of Genesis, which as of September 30, 2005 was $32.6 million, plus $5.8 million in outstanding letters of credit. There are no guarantees by Denbury or any of its other subsidiaries of the debt of Genesis or of Genesis Energy, Inc.

Over the past several years, including the period prior to our investment in Genesis, we sold certain of our oil production to Genesis. Beginning in September 2004, we discontinued most of our direct oil sales to Genesis and began to transport our crude oil using Genesis' Mississippi common carrier pipeline to a sales point where it is sold to third party purchasers. For these transportation services, we pay Genesis a fee for the use of their pipeline and

trucking services. For the three and nine months ended September 30, 2005, we expensed $1.0 million and $3.0 million, respectively, for these transportation services. For the three and nine months ended September 30, 2004, we expensed $266,000 under this transportation agreement. We recorded oil sales to Genesis of $1.4 million and $20.6 million for the respective quarters ended September 30, 2005 and 2004, and $3.4 million and $62.9 million for the respective nine months ended September 30, 2005 and 2004. Denbury received other miscellaneous payments from Genesis for the nine months ended September 30, 2005 and 2004, including $90,000 in each period of director fees for certain executive officers of Denbury that are board members of Genesis, and $387,000 and $373,000, respectively, in pro rata dividend distributions from Genesis as part of Genesis' cash distributions to all of its public holders.

Transportation Leases

In late 2004 and early 2005, we entered into pipeline transportation agreements with Genesis to transport in its pipelines our crude oil from Olive, Brookhaven, and McComb Fields in Southwest Mississippi to Genesis' main crude oil pipeline in order to improve our ability to market our crude oil, and to transport CO2 from our main CO2 pipeline to Brookhaven Field for our tertiary operations. As part of these arrangements, we entered into three transportation agreements. The first agreement, entered into in November 2004, was to transport crude oil from Olive Field. This agreement is for 10 years and has a minimum payment of approximately $18,000 per month. In December 2004, we entered into a second transportation agreement, to transport CO2 to Brookhaven Field in Southwest Mississippi. This agreement is for an eight-year period and has minimum payments of approximately $49,000 per month. In January 2005, we entered into a third transportation agreement to transport crude oil from Brookhaven Field. This agreement is for 10 years and has a minimum payment of approximately $32,000 per month. The minimum monthly payment in each agreement will increase for any volumes transported in excess of the stated monthly volume in the contract. Genesis operates and maintains these pipelines at its own expense.

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. At September 30, 2005, we had $6.6 million of capital lease obligations recorded as liabilities in our Condensed Consolidated Balance Sheet, of which $560,000 was current. At December 31, 2004, we had $4.6 million of capital lease obligations recorded as liabilities in our Condensed Consolidated Balance Sheet, of which $375,000 was current.

CO2 Volumetric Production Payments

In November 2003, we sold 167.5 Bcf of CO2 to Genesis for $24.9 million ($23.9 million as adjusted for interim cash flows from the September 1, 2003 effective date and for transaction costs) under a volumetric production payment ("VPP"), and assigned to Genesis three of our existing long-term commercial CO2 supply agreements with our industrial customers. These industrial contracts represented approximately 60% of our then current industrial CO2 sales volumes. Pursuant to the VPP, Genesis may take up to 52.5 MMcf/d of CO2 through 2009, 43.0 MMcf/d from 2010 through 2012, and 25.2 MMcf/d to the end of the term.

On August 26, 2004, we closed on another transaction with Genesis, selling to them a 33.0 Bcf volumetric production payment ("VPPII") of CO2 for $4.8 million ($4.6 million as adjusted for interim cash flows from the July 1 effective date and for transaction costs) along with a related long-term supply agreement with an industrial customer. Pursuant to the VPPII, Genesis may take up to 9 MMcf/d of CO2 to the end of the contract term.

We have recorded the net proceeds of these volumetric production payment sales as deferred revenue and will recognize such revenue as CO2 is delivered during the term of the two volumetric production payments. At September 30, 2005 and December 31, 2004, $23.8 million and $25.8 million, respectively, was recorded as deferred revenue of which $2.4 million was included in current liabilities at September 30, 2005 and December 31, 2004. We recognized deferred revenue of $0.7 million during each of the three month periods ended September 30, 2005 and 2004 and $2.0 and $1.8 million for the nine months ended September 30, 2005, respectively, for deliveries under the VPP and VPPII. We provide Genesis with certain processing and transportation services in connection with these agreements for a fee of approximately $0.16 per Mcf of CO2 delivered to their industrial customers, which resulted in $0.8 million and $0.7 million in revenue to Denbury for the three months ended September 30, 2005 and 2004 and $2.3 million and $1.9 million for the nine months ended September 30, 2005 and 2004, respectively.

Summarized financial information of Genesis Energy, L.P. (amounts in thousands):

	Three Months Ended September 30,		Nin
	2005	2004	2
Revenues	$ 300,577	$ 250,736	$

Cost of sales	300,686	250,892	
Other expenses	532	203	
Income (loss) from discontinued operations	45	(35)	
Net income (loss)	$ (596)	$ (394)	$

	September 30, 2005	December 31, 2004
Current assets	$ 107,456	$ 77,396
Non-current assets	79,163	65,758
Total assets	$ 186,619	$ 143,154
Current liabilities	$ 109,437	$ 81,938
Non-current liabilities	32,786	15,460
Partners' capital	44,396	45,756
Total liabilities and partners' capital	$ 186,619	$ 143,154

DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts and accordingly de-designated our derivative instruments from hedge accounting treatment. As a result of this change, we began accounting for our oil and natural gas derivative contracts as speculative contracts in the first quarter of 2005. As speculative contracts, the changes in the fair value of these instruments are recognized in income in the period of change. Additionally, the balance remaining in accumulated comprehensive income at December 31, 2004 related to the derivative contracts is being amortized over the remaining life of the contracts, all of which expire in 2005. While this may result in more volatility in our net income than if we had continued to apply hedge accounting treatment as permitted by SFAS No. 133, we believe that the benefits associated with applying hedge accounting do not outweigh the cost, time and effort required to comply with hedge accounting.

We enter into various financial contracts to economically hedge 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 historically consisted of price floors, collars and fixed price swaps. Historically, we have generally attempted to hedge between 50% and 75% of our anticipated production each year to provide us with a reasonably certain amount of cash flow to cover a majority of our budgeted exploration and development expenditures without incurring significant debt, although our hedging percentage may vary relative to our debt levels. For 2005 and beyond, we have hedged significantly less, primarily because of our strong financial position resulting from our lower levels of debt relative to our cash flow from operations. When we make a significant acquisition, we generally attempt to hedge a large percentage, up to 100%, of the forecasted production for the subsequent one to three years following the acquisition in order to help provide us with a minimum return on our investment. All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures, which are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification.

For the 2004 period, the following is a summary of the net loss on our commodity contracts that qualified for hedge accounting and is included in "Loss on effective hedge contracts" in our Condensed Consolidated Statements of Operations:

(In Thousands)	Three Months Ended September 30, 2004	Nine Mon September
Settlements of hedge contracts - Oil	$ (13,455)	$
Settlements of hedge contracts - Gas	(4,010)	
Loss on effective hedge contracts	$ (17,465)	$

DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following is a summary of "Commodity Derivative Expense" included in our Condensed Consolidated Statements of Operations:

(In Thousands)	Three Months Ended September 30,	
	2005	2004

Settlements of derivative contracts not designated as hedges - Oil	$ -	$ 4,778
Settlements of derivative contracts not designated as hedges - Gas	3,765	-
Hedge ineffectiveness on contracts qualifying for hedge accounting	-	(1,551
Reclassification of accumulated other comprehensive income balance	1,875	1,206
Adjustments to fair value associated with contracts no longer designated as hedges	6,178	1,747
Adjustment to fair value associated with contracts transferred in sale of offshore production	-	(1,019
Commodity derivative expense	$ 11,818	$ 5,161

Derivative Contracts at September 30, 2005

Crude Oil Contracts:

	NYMEX Contract Prices Per Bbl				
			Collar Prices		Fair Value at
Type of Contract and Period	Bbls/d	Floor Price	Floor	Ceiling	September 30, 2 (In Thousands)
Floor Contracts					
Oct. 2005 - Dec. 2005	7,500	$ 27.50	-	-	$

Natural Gas Contracts:

	NYMEX Contract Prices Per MMBtu				
			Collar Prices		Fair Value at
Type of Contract and Period	MMBtu/d	Floor Price	Floor	Ceiling	September 30, 2 (In Thousands)
Collar Contracts					
Oct. 2005 - Dec. 2005	15,000	-	$ 3.00	$ 5.50	$ (11,

At September 30, 2005, our derivative contracts were recorded at their fair value, which was a net liability of $11.4 million. The balance in accumulated other comprehensive loss of $1.4 million at September 30, 2005, represents the unamortized deficit in the fair market value of our derivative contracts as compared to the cost of our hedges, net of income taxes, associated with our derivative contracts that we de-designated from hedge accounting effective January 1, 2005. The $1.4 million in accumulated other comprehensive loss as of September 30, 2005 will be amortized by December 31, 2005.

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(In Thousands)	September 30, 2005	December 31, 2004
Accounts payable	$ 18,067	$ 26,262
Accrued compensation	5,133	5,613
Accrued exploration and development costs	25,307	5,439
Accrued interest	8,468	4,219
Asset retirement obligations - current	1,315	2,596
Other	12,026	5,300
Total	$ 70,316	$ 49,429

7. SUBSEQUENT EVENTS

On October 19, 2005, 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 100,000,000 shares to 250,000,000 shares and to split our common stock on a 2-for-1 basis. Stockholders of record on October 31, 2005, 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.

In October 2005, we sold 80.0 Bcf of CO2 to Genesis for $14.7 million under a volumetric production payment, and assigned to Genesis two of our existing long-term commercial CO2 supply agreements with our industrial customers. Net proceeds will be reflected as deferred revenue and will be recognized as revenues as the CO2 is delivered during the term of the volumetric production payment.

8. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On December 29, 2003, we amended the indenture for our 7.5% Senior Subordinated Notes due 2013 to reflect our new holding company organizational structure. As part of this restructuring our indenture was amended so that both Denbury Resources Inc. and Denbury Onshore, LLC became co-obligors of our subordinated debt. The co-obligations are full and unconditional and are joint and several. Prior to this restructure, Denbury Resources Inc. was the sole obligor. Our subordinated debt is fully and unconditionally guaranteed jointly and severally by all of Denbury Resources Inc.'s subsidiaries other than minor subsidiaries. The results of our equity interest in Genesis is 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 significant subsidiaries:

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Condensed Consolidating Balance Sheets

Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
	September 30, 2005		
ASSETS			
Current assets	$ 221,680	$ 141,462	$ 3,080
Property and equipment	-	1,069,432	54
Investment in subsidiaries (equity method)	448,263	-	446,847
Other assets	2,338	10,790	286
Total assets	$ 672,281	$ 1,221,684	$ 450,267
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities	$ -	$ 335,849	$ 1,950
Long-term liabilities	-	445,657	54
Stockholders' equity	672,281	440,178	448,263
Total liabilities and stockholders' equity	$ 672,281	$ 1,221,684	$ 450,267

Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
	December 31, 2004		
ASSETS			
Current assets	$ 1	$ 171,997	$ 204,709
Property and equipment	-	796,578	784
Investment in subsidiaries (equity method)	541,671	-	333,907
Other assets	-	15,707	2,271
Total assets	$ 541,672	$ 984,282	$ 541,671
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities	$ -	$ 286,767	$ -
Long-term liabilities	-	370,399	-
Stockholders' equity	541,672	327,116	541,671
Total liabilities and stockholders' equity	$ 541,672	$ 984,282	$ 541,671

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DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Condensed Consolidating Statements of Operations

	Three Months Ended Septem		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Revenues	$ -	$ 141,858	$ -
Expenses	41	82,825	383
Income (loss) before the following:	(41)	59,033	(383)
Equity in net earnings of subsidiaries	38,571	-	38,724
Income before income taxes	38,530	59,033	38,341
Income tax provision (benefit)	(16)	20,254	(230)
Net income	$ 38,546	$ 38,779	$ 38,571

	Three Months Ended Septem		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Revenues	$ -	$ 81,977	$ 6,008
Expenses	42	56,651	5,149
Income (loss) before the following:	(42)	25,326	859
Equity in net earnings of subsidiaries	18,299	-	20,625
Income before income taxes	18,257	25,326	21,484
Income tax provision (benefit)	(17)	4,664	3,185
Net income	$ 18,274	$ 20,662	$ 18,299

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DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Condensed Consolidating Statements of Operations (continued)

	Nine Months Ended Septemb		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Revenues	$ -	$ 383,203	$ -
Expenses	123	219,509	862
Income (loss) before the following:	(123)	163,694	(862)
Equity in net earnings of subsidiaries	109,360	-	109,934
Income before income taxes	109,237	163,694	109,072
Income tax provision (benefit)	(48)	54,036	(288)
Net income	$ 109,285	$ 109,658	$ 109,360

	Nine Months Ended Septemb		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Revenues	$ -	$ 228,504	$ 63,486
Expenses	130	166,044	37,699
Income (loss) before the following:	(130)	62,460	25,787
Equity in net earnings of subsidiaries	60,051	-	45,743
Income before income taxes	59,921	62,460	71,530
Income tax provision (benefit)	(46)	16,689	11,479
Net income	$ 59,967	$ 45,771	$ 60,051

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DENBURY RESOURCES INC.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Condensed Consolidating Statements of Cash Flows

	Nine Months Ended Septemb		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Cash flow from operations	$ (6,020)	$ 236,921	$ 400
Cash flow from investing activities	-	(252,963)	(21)
Cash flow from financing activities	6,020	19,614	-
Net increase in cash	-	3,572	379
Cash, beginning of period	1	32,881	157
Cash, end of period	$ 1	$ 36,453	$ 536

	Nine Months Ended Septemb		
Amounts in thousands	Denbury Resources Inc. (Parent and Co-Obligor)	Denbury Onshore, LLC (Issuer and Co-Obligor)	Guarantor Subsidiaries
Cash flow from operations	$ (8,386)	$ 317,322	$ (157,965)
Cash flow from investing activities	-	(172,986)	157,995
Cash flow from financing activities	8,386	(75,412)	-
Net increase in cash	-	68,924	30
Cash, beginning of period	1	24,174	13
Cash, end of period	$ 1	$ 93,098	$ 43

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, 2004, 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 an 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 reserves of carbon dioxide ("CO2") used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage onshore Louisiana and in the Barnett Shale play near Fort Worth, Texas. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling, and proven engineering extraction processes, including secondary and tertiary recovery operations. Our corporate headquarters are in Plano, Texas (a suburb of Dallas), and we have two primary field offices located in Houma, Louisiana, and Laurel, Mississippi.

OVERVIEW

STOCK SPLIT. On October 19, 2005, our stockholders approved an amendment to our certificate of incorporation to increase our authorized shares of common stock from 100 million shares to 250 million shares and to split our common stock on a two-for-one basis. Stockholders of record as of the close of business on October 31, 2005 received one additional share of Denbury common stock for each share of common stock held at that time. All per share numbers included herein have been restated for this two-for-one split.

IMPACT OF HURRICANES KATRINA AND RITA. During August and September, 2005, Hurricanes Katrina and Rita came ashore negatively affecting almost all of our existing production. While we did not incur any significant property damage as a result of either storm, we estimate that we lost approximately 350,000 barrels of oil equivalent ("BOE") of production during the third quarter as most of our fields were shut-in for periods ranging from several days to a few weeks, primarily because of a lack of power or because of flooding. As a result, production was lower in the third quarter than in the immediately prior quarter in every area of our operations except for the Barnett Shale play in Texas. While almost all of our wells had been returned to production by late October, we estimate that we lost an additional 500 BOE/d of production in the fourth quarter as a result of the two hurricanes.

Many of our operating statistics were affected by the decreased production. Operating costs and general and administrative costs per BOE were higher in the third quarter as a result of the reduced production levels. We also incurred approximately $1.6 million to provide food, water, gasoline, power generators, and other essential supplies to our employees and charitable organizations in Mississippi and Louisiana following the storms, most of which was expensed, further increasing our general and administrative costs on both a gross and per BOE basis.

CONTINUED EXPANSION OF OUR TERTIARY OPERATIONS. Since we acquired our first

carbon dioxide tertiary flood in Mississippi nearly six years ago, 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 CO2 that we own drive the play. Please refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the sections entitled "Overview" and "CO2 Operations" contained in our 2004 Form 10-K for further information regarding these operations, their potential, and the ramifications of this change in focus.

Near the end of October 2005, we reached total depth and logged another CO2 source well. Preliminary analysis of the well logs indicate CO2 reserves in excess of one Tcf, subject to confirmation through production tests, gas composition analysis, and delineation of the reservoir. This is in addition to the estimated 130 Bcf of proved CO2 reserves that we added from another CO2 source well drilled in the first half of 2005. If preliminary estimates are correct, this will give us additional CO2 reserves to further expand our tertiary operations and potentially add another phase of operations.

Oil production from our tertiary operations decreased slightly as a result of the two hurricanes (see "Impact of Hurricanes Katrina and Rita" above) to 8,850 BOE/d in the third quarter of 2005, a 6% decrease compared to our second quarter 2005 tertiary production level of 9,417 BOE/d, but still a 27% increase over our third quarter of 2004 average tertiary production level of 6,967 BOE/d. As a result of the hurricanes and other delays, we have reduced our targeted 2005 average rate of oil production from tertiary operations from our prior estimate of between 9,500 and 9,750 BOE/d to a revised estimated range between 9,250 and 9,500 BOE/d. Generally, our fields are performing as anticipated, but

with our tertiary fields shut-in briefly as a result of the hurricanes and other delays, our 2005 annual production will not be as high as originally expected. In addition, the timing of specific well responses is not always possible to accurately forecast, thus there could be variances from our expected long-term oil production forecast.

OPERATING RESULTS. Despite the negative impact on earnings from the two hurricanes (see above), earnings and cash flow from operations were at near-record quarterly and nine month levels for the 2005 periods, primarily as a result of high commodity prices. Production was lower in the respective 2005 periods, primarily as a result of the sale of our offshore properties early in the third quarter of 2004 and as a result of the production lost from the two hurricanes. Our total production, when comparing the two third quarters, decreased 8% in the 2005 period. Adjusting for the offshore sale, our total production was almost the same in the two third quarters, even though the third quarter of 2005 was negatively impacted by the loss of approximately 3,800 BOE/d as a result of the two hurricanes.

Higher commodity prices more than offset the lower production levels, resulting in net income of $38.5 million during the third quarter of 2005 as compared to $18.3 million of net income during the third quarter of 2004. Included in third quarter of 2005 net income is the effect of approximately $8.1 million ($5.3 million after tax) of mark-to-market expense and non-cash amortization expense of accumulated other comprehensive income that related to

our decision to discontinue hedge accounting in 2005 (see "Market Risk Management").

Cash payments on our commodity hedges were significantly lower in the third quarter of 2005 than in the third quarter of 2004, as most of our out-of-the-money hedges expired as of December 31, 2004. Total cash payments on hedges were approximately $3.8 million in the third quarter of 2005 as compared to $22.2 million paid during the third quarter of 2004.

Most of our expenses increased on a per BOE basis during the 2005 period due to (i) rising costs in the industry, (ii) a higher percentage of operations related to tertiary operations (which have higher operating costs per BOE), and (iii) lower production levels in the 2005 period following our offshore property sale in July 2004 and production lost from the two hurricanes. See "Results of Operations" for a more thorough discussion of our operating results. We are also experiencing significant cost inflation in our industry, as evidenced by the cost increases in almost every aspect of our business, and if commodity prices remain high and demand for goods and services remain strong, we expect this inflationary trend to continue.

Our operating results for the comparative first nine months of 2005 and 2004 were generally consistent with the summary discussed above for the respective third quarters. Earnings and cash flow from operations increased over the prior-year period due to the higher commodity prices and lower hedge payments, offset in part by lower production due to the offshore sale in July 2004 and the hurricanes in the third quarter of 2005. Most expenses on a per BOE basis increased in the first nine months of 2005 period for the reasons noted above.

CAPITAL RESOURCES AND LIQUIDITY

Our current capital budget for 2005, excluding any potential acquisitions, is approximately $365 million, which at commodity futures prices as of the end of October 2005, will be reasonably close to our anticipated cash flow from operations. The capital budget includes an estimated $50 million of expenditures for a CO2 pipeline being constructed to East Mississippi, which we may refinance upon completion by entering into some type of long-term financing, effectively paying for the cost of the pipeline over time and recouping cash previously spent. As has been our practice in the past, we attempt to reinvest all of our available cash flow and profits to find additional reserves and increase production. 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. As a result of the recent cost inflation in our industry, we are having to continually review and increase our capital budget each quarter, or consider the elimination of a portion of our planned projects. We have not yet set our 2006 capital budget, but it is likely to be significantly higher than our 2005 budget and is preliminarily expected to be between $450 million and $500 million, a level that is reasonably close to our anticipated cash flow from operations using current prices. Preliminarily, approximately 50% of the budget would be spent on tertiary related operations,

approximately 25% in the Barnett Shale area, approximately 10% on exploration projects, and the balance on our properties in Mississippi or Louisiana. The

2006 budget will be set and approved by our Board of Directors at our next regularly scheduled board meeting in December 2005.

In addition to our capital exploration and development budget, during the first nine months of 2005 we also spent approximately $71.2 million on acquisitions, primarily for interests in other oil fields that may be tertiary flood candidates and for additional acreage and interests in the Barnett Shale play near Fort Worth, Texas. We are continuing to pursue additional acquisitions of a similar nature during the remainder of 2005 and in 2006, some of which may have higher existing production and therefore be more expensive, although it is not practical to forecast if these will be successful or in what amounts.

At September 30, 2005, we had used our remaining cash and short-term investments from the 2004 sale of our offshore properties and had borrowed $20 million on our bank credit line, primarily to fund acquisitions. We repaid $10 million on our line in October 2005 with proceeds from another transaction with Genesis Energy, L.P. ("Genesis"), selling them a volumetric production payment of 80 Bcf of CO2 for $14.7 million along with two related long-term CO2 supply agreements with two industrial customers. Based on current prices, we anticipate that our cash flow will be sufficient for the remainder of the year to fund our currently planned capital expenditures, although there could be short-term borrowings and repayments under our bank line depending on the timing of such expenditures. If we are successful in making further acquisitions, these would likely be initially funded under our bank credit line.

At September 30, 2005, we had outstanding $225 million (principal amount) of 7.5% subordinated notes due in 2013, approximately $6.6 million of capital lease commitments, $20 million of bank debt, and working capital of $28.4 million. We amended our bank agreement in April 2005 to (i) reaffirm our $200 million borrowing base, and (ii) allow us to borrow up to $80 million in a bond issue from a Mississippi governmental authority, resulting in the exemption or reduction of sales and ad valorem taxes on CO2 facilities we build through May 2007 in Mississippi. This bond funding arrangement was completed in April 2005 to replace a prior two year program that expired as of May 1, 2005. Any borrowing under this bond program will be purchased by the banks in our credit facility, will become part of our outstanding borrowings under our credit line and will accrue interest and be repaid on the same basis as our bank line. Our borrowing base was reaffirmed again in September 2005.

SOURCES AND USES OF CAPITAL RESOURCES

During the first nine months of 2005, we spent $210.9 million on oil and natural gas exploration and development, $49.9 million on CO2 exploration and development (including $27.9 million on our CO2 pipeline being constructed to East Mississippi), and approximately $71.2 million on property acquisitions, for total capital expenditures of approximately $332.0 million. Our exploration and development expenditures included approximately $94.9 million for drilling, $20.1 million for geological, geophysical and acreage expenditures and $95.8 million for facilities and recompletion costs. Our year-to-date acquisition expenditures include the purchase of additional interest and acreage in the Barnett Shale area and purchase of two oil fields that may be potential tertiary flood candidates in the future, Cranfield and Lake St. John fields. We funded these expenditures with $231.3 million of cash flow from operations, $20.0 million of net bank borrowings, and a $19.9 million increase in our accrued capital expenditures, with the balance funded with cash remaining from our 2004 offshore property sale. Adjusted cash flow from operations (a non-GAAP measure defined as cash flow from operations before changes in assets and liabilities as discussed below under "Results of Operations - Operating Results" below) was $238.7 million for the first nine months of 2005, while cash flow from operations for the same period, the GAAP measure, was $231.3 million.

During the first nine months of 2004, we spent $125.8 million on oil and

natural gas exploration and development, $35.2 million on CO2 exploration and development, and approximately $11.6 million on property acquisitions (principally CO2 producing assets), for total capital expenditures of approximately $172.6 million. We funded these expenditures with $151.0 million of cash flow from operations, with the balance funded with net proceeds from the July 2004 offshore sale. We also paid back all of our bank debt during the period with the offshore sale proceeds, leaving us with approximately $93.1 million of cash and $32.0 million of short-term investments as of September 30, 2004, although $16.0 million of this cash was refunded to the purchaser of our offshore assets in October 2004. During the third quarter of 2004, we closed on another transaction with Genesis, selling to them a 33.0 Bcf volumetric production payment of CO2 for $4.8 million along with a related long-term CO2 supply agreement with an industrial customer, further increasing our cash position. Adjusted cash flow from operations (a non-GAAP measure defined as cash

flow from operations before changes in assets and liabilities as discussed below under "Results of Operations - Operating Results") was $151.7 million for the first nine months of 2004.

OFF-BALANCE SHEET ARRANGEMENTS

Commitments and Obligations

Our obligations that are not currently recorded on our balance sheet are 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 undeveloped proved reserves, we must also fund the associated future development costs as forecasted in our proved reserve reports. Further, one of our subsidiaries, the general partner of Genesis Energy, L.P., has guaranteed the bank debt of Genesis (which as of September 30, 2005, consisted of $32.6 million of debt and $5.8 million in letters of credit), and we have delivery obligations to deliver CO2 for Genesis and to our industrial customers. Our hedging obligations are discussed in Note 5 to the Unaudited Condensed Consolidated Financial Statements. Neither the amounts nor the terms of these commitments or contingent obligations have changed significantly from the year-end 2004 amounts reflected in our Form 10-K filed in March 2005. Please refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our 2004 Form 10-K for further information regarding our commitments and obligations.

RESULTS OF OPERATIONS

CO2 Operations

As described in the "Overview" section above, our CO2 operations are 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 CO2, and we have outlined certain of this potential in our annual report and other public disclosures. In addition to its long-term effect, this shift in focus 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 "CO2 Operations" contained in our 2004 Form 10-K for further information regarding

these matters.

Near the end of October 2005, we reached total depth and logged another CO2 source well. Preliminary analysis of the well logs indicate CO2 reserves in excess of one Tcf, subject to confirmation through production tests, gas composition analysis, and delineation of the reservoir. Additionally, we added an estimated 130 Bcf of proved CO2 reserves that we added from another CO2 source well drilled in the first half of 2005. If preliminary estimates are correct, this will give us additional CO2 reserves to further expand our tertiary operations. We have in inventory two oil fields (Cranfield and Lake St John fields) purchased earlier this year that will likely be part of a future tertiary phase, and we are actively seeking to acquire additional oil properties for this purpose.

During the first nine months of 2005, our CO2 production averaged 238 MMcf/d. We used 71% of this, or 170 MMcf/d, in our tertiary operations, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payment. We believe that our current production capacity of CO2 is approximately 400 MMcf/d prior to the completion of our latest well, and anticipate that our latest well could increase our production capability to 450 or 500 MMcf/d. One more CO2 source well is expected to be started before the end of 2005. These wells are intended not only to increase CO2 production, but also to increase our CO2 reserves. We have completed a 3-D seismic shoot over the Jackson Dome area and are currently processing and evaluating several prospects for potential CO2 reserves.

Our oil production from our CO2 tertiary recovery activities in the third quarter of 2005 decreased 6% over second quarter 2005 levels as a result of the production lost from the hurricanes, but increased 27% over third quarter 2004 levels, to 8,850 Bbls/d in the third quarter of 2005, with production increases at all three producing fields, Little Creek, Mallalieu and McComb Fields.

	Average Daily Production (BOE/d)				
Tertiary Oil Field	First Quarter 2004	Second Quarter 2004	Third Quarter 2004	Fourth Quarter 2004	First Quarter 2005
Little Creek & Lazy Creek	3,192	3,288	3,125	2,989	3,709
Mallalieu (East and West)	3,105	3,172	3,410	3,712	4,235
McComb & Olive	21	143	432	541	700
Total tertiary oil production	6,318	6,603	6,967	7,242	8,644

We are currently injecting CO2 into two other oil fields, Brookhaven and Smithdale. The larger of the two, Brookhaven, has not responded to date and is not expected to respond until early next year. During October 2005, we had our first minor production response from Smithdale Field, but production from this field is unlikely to be significant until 2006 or beyond, and due to the smaller

size of this field, its ultimate production rate is expected to be much less than that at Little Creek or Mallalieu. On a consolidated basis, we expect our tertiary oil production to continue to grow for the foreseeable future.

Our operations in this area, as well as others, have had minor delays during 2005. These delays are caused by various factors: difficulties reentering a few injection wells, which has required that some wells be redrilled; delays in getting certain permits and right-of-ways; delays caused by the two hurricanes; and a general tightening of available materials and equipment in the industry. As a result of these delays and the lost production related to the hurricanes, we have reduced our targeted 2005 average rate of oil production from tertiary operations from our prior estimated range of 9,500 to 9,750 BOE/d to a revised estimated range between 9,250 and 9,500 BOE/d. Generally, the fields are performing as anticipated, but with the tertiary fields shut-in briefly as a result of the hurricanes and the other delays, 2005 production will not be as high as originally expected. In addition, the timing of specific well responses is not always possible to accurately forecast, so we could experience variances from our expected long-term oil production forecast.

We spent approximately $0.15 per Mcf to produce our CO2 during the first nine months of 2005, slightly higher than the 2004 nine month average cost of $0.12 per Mcf, principally as a result of higher commodity prices, which result in higher royalty payments. Our estimated total cost per thousand cubic feet of CO2 during the first nine months of 2005 was approximately $0.22, after inclusion of depreciation and amortization expense, up slightly from the 2004 average of $0.21 per Mcf. On a quarterly basis, we spent approximately $0.17 per Mcf to produce our CO2 during the third quarter of 2005, slightly higher than the 2004 third quarter average of $0.14 per Mcf, but consistent with the nine month trend, as a result of higher commodity prices. Our estimated total cost per thousand cubic feet of CO2 during the third quarter of 2005 was approximately $0.25, after inclusion of depreciation and amortization expense.

For the first nine months of 2005, our operating costs for our tertiary properties averaged $11.04 per BOE, higher than the $9.84 per BOE average in the first nine months of 2004 and our 2004 annual average of $9.90 per BOE. The higher costs were a result of the higher fuel and energy costs (which represent almost 38% of the total operating costs excluding the cost of CO2) and general cost inflation in the industry, partially offset by higher oil production levels.

Operating Results

As summarized in the "Overview" section above and discussed in more detail below, higher commodity prices, and lower hedge payments more than offset lower production levels and higher operating expenses, resulting in near-record quarterly earnings and cash flow from operations. Included in the first nine months of 2005 net income is the effect of approximately $12.0 million ($8.0 million after tax) of non-cash expense related to our decision to discontinue hedge accounting in 2005 and the resultant mark-to-market adjustments and amortization of other comprehensive income.

Three Months Ended N

	September 30,		
Amounts in thousands, except per share amounts	2005	2004	2
Net income	$ 38,546	$ 18,274	$
Net income per common share - basic	0.34	0.17	
Net income per common share - diluted	0.32	0.16	
Adjusted cash flow from operations (see below)	$ 87,346	$ 29,747	$
Net change in assets and liabilities relating to operations	(11,059)	15,019	
Cash flow from operations (1)	$ 76,287	$ 44,766	$

(1) Net cash flow provided by operations as per the Unaudited Condensed Consolidated Statements of Cash Flows.

Adjusted cash flow from operations is a non-GAAP measure that represents cash flow provided by operations before changes in assets and liabilities, as calculated from our Unaudited Condensed Consolidated Statements of Cash Flows. Cash flow from operations is the GAAP measure as presented in our Unaudited Condensed Consolidated Statements of Cash Flows. In our discussion herein, we have elected to discuss these two components of cash flow provided by operations separately.

Adjusted cash flow from operations, the non-GAAP measure, measures the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe that this is important to consider adjusted cash flow from operations separately, as we believe it can often be a better way to discuss changes in operating trends in our business caused by changes in production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during that reporting period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices or significant changes in drilling activity.

The net change in assets and liabilities relating to operations is also important as it does require or provide additional cash for use in our business; however, we prefer to discuss its effect separately. During the first nine months of 2005 our accrued production receivables and trade accounts receivable increased as a result of higher revenue and increased spending, resulting in a $14.3 million use of cash; however, this was partially offset by the increase in our accounts payable, accrued liabilities and production payable which resulted in additional cash resources of $7.5 million. During the third quarter of 2004, we collected accrued production receivables related to offshore production that existed as of the closing date of the sale of Denbury Offshore, Inc. that were for the benefit of Newfield Exploration Company, the purchaser. As of September 30, 2004, we owed Newfield approximately $16.0 million for these receivables and other sale adjustments, the primary reason for the $15.0 million net change in assets and liabilities relating to operations above for the third quarter of 2004. During the first nine months of 2004, we spent $7.5 million (in the second quarter) to acquire 7,500 Bbls/d of oil puts or floors for 2005 and to retire 20 MMcf/d of natural gas hedges for the balance of 2004, although this amount was more than offset by the payable to Newfield at September 30, 2004.

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2005 and 2004 are included in the following table.

DENBURY RESOURCES INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nin S
	2005	2004	200
Average daily production volumes			
Bbls/d	18,369	19,206	1
Mcf/d	53,854	62,708	5
BOE/d (1)	27,345	29,657	2
Operating revenues (Thousands)			
Oil sales	$ 95,987	$ 68,144	$ 26
Natural gas sales	42,561	34,924	11
Total oil and natural gas sales	$ 138,548	$103,068	$ 37
Hedge Contracts (2) (Thousands)			
Cash expense on settlements of hedge contracts	$ 3,765	$ 22,243	$
Non-cash hedge expense	8,053	383	1
Total expense from hedge contracts	$ 11,818	$ 22,626	$ 1
Operating expenses (Thousands)			
Lease operating expenses	$ 25,983	$ 19,781	$ 7
Production taxes and marketing expenses	7,018	4,900	1
Total production expenses	$ 33,001	$ 24,681	$ 9
CO2 sales and transportation fees (3)	$ 2,594	$ 1,681	$
CO2 operating expenses	631	255	
CO2 operating margin	$ 1,963	$ 1,426	$
Unit prices - including impact of hedge settlements			
Oil price per Bbl	$ 56.80	$ 28.25	$
Gas price per Mcf	7.83	5.36	
Unit prices - excluding impact of hedge settlements			
Oil price per Bbl	$ 56.80	$ 38.57	$
Gas price per Mcf	8.59	6.05	
Oil and gas operating revenues and expenses per BOE (1):			
Oil and natural gas revenues	$ 55.07	$ 37.78	$
Oil and gas lease operating expenses	$ 10.33	$ 7.25	$
Oil and gas production taxes and marketing expense	2.79	1.80	

Total oil and gas production expenses	$ 13.12	$ 9.05	$

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

(2) See also "Market Risk Management" below for information concerning the Company's hedging transactions. Effective January 1, 2005, we elected to discontinue hedge accounting for our oil and natural gas derivative contracts, see Note 5 to the Condensed Consolidated Financial Statements.

(3) Includes deferred revenue of $0.7 million and $0.7 million for the three months ended September 30, 2005 and 2004, respectively, and $2.0 million and $1.8 million for the nine months ended September 30, 2005 and 2004, respectively, associated with a volumetric production payment with Genesis. Includes transportation income from Genesis of $0.8 million and $0.7 million for the three months ended September 30, 2005 and 2004, respectively, and $2.3 million and $0.7 million for the nine months ended September 30, 2005 and 2004, respectively.

PRODUCTION: Production by area for each of the quarters of 2004 and the first, second, and third quarters of 2005 is listed in the following table.

	Average Daily Production (BO				
Operating Area	First Quarter 2004	Second Quarter 2004	Third Quarter 2004	Fourth Quarter 2004	First Quarter 2005
Mississippi - non-CO2 floods	12,754	13,048	12,969	13,564	13,057
Mississippi - CO2 floods	6,318	6,603	6,967	7,242	8,644
Onshore Louisiana	8,825	7,492	7,033	7,182	6,710
Barnett Shale	229	345	803	963	1,313
Other (1)	-	-	-	-	-
Total production excluding offshore	28,126	27,488	27,772	28,951	29,724
Offshore Gulf of Mexico - sold July 2004	8,521	9,114	1,885	26	-
Total Company	36,647	36,602	29,657	28,977	29,724

(1) Primarily represents production from an offshore property retained from the sale in July 2004.

As discussed in the "Overview - Impact of Hurricanes Katrina and Rita" above, we estimate that we lost approximately 350,000 BOE of production (or approximately 3,800 BOE/d) as a result of Hurricanes Katrina and Rita during the third quarter of 2005 as almost all of our fields were shut-in for periods

ranging from several days to a few weeks, primarily because of a lack of power or flooding. As a result, production was lower in the third quarter of 2005 than in the prior quarter in almost every operating area. We sold our offshore properties in July 2004, contributing to an overall production decline on a year-to-date basis. Such production is listed separately in the above table for comparative purposes.

Production in the Mississippi non-CO2 floods decreased from the prior quarter as a result of the shut-ins relating to the hurricanes, as otherwise this area's production has remained relatively stable over the last several quarters. Although most of the oil production in this area is on a gradual decline, the natural gas drilling in the Selma Chalk formation at Heidelberg Field has generally offset these declines. Even with the effects of the hurricanes, natural gas production at Heidelberg averaged 13.2 MMcf/d in the third quarter of 2005, almost the same as the 13.5 MMcf/d produced in the third quarter of 2004.

As more fully discussed in "CO2 Operations" above, oil production from our tertiary operations averaged 8,850 Bbls/d in the third quarter of 2005, representing 48% of our third quarter corporate oil production and 32% of our total corporate production on a BOE basis. Production in our CO2 floods was higher year-over-year in spite of the storms, as the production growth from this area was more than enough to overcome the lost production from the temporary shut-ins.

Our onshore Louisiana production has generally declined over the last year or two, partially offset by incremental production from occasional new wells, with the most significant decreases at Thornwell and Lirette Fields. Production at Thornwell averaged 975 BOE/d in the third quarter of 2005, as compared to 1,104 BOE/d in the third quarter of 2004, down only slightly as the production from recent completions almost offset the otherwise declining production. Thornwell Field was also one of the Louisiana Fields that was impacted the least by the two hurricanes. Production at Lirette declined to 974 BOE/d in the third quarter of 2005 from 2,133 BOE/d in the third quarter of 2004, decreasing from both normal declines and production loss from the storms. Both of these fields are characterized by natural gas wells that are relatively short-lived in nature, and field production is expected to continue to decline unless offset by new wells. Partially offsetting these declines was incremental production from new wells in this area resulting from drilling in late 2004 and 2005, primarily in the South Chauvin Field area.

Natural gas production in the Barnett Shale has increased as a result of increased drilling activity in 2004 and early 2005 and the acquisition of additional interests during the second quarter of 2005, increasing production

from 803 BOE/d (4.8 MMcf/d) in the third quarter of 2004 to 2,150 BOE/d (12.9 MMcf/d) in the third quarter of 2005. Approximately 1.5 MMcf/d of the increase in the second quarter of 2005 is related to the acquisition of additional interests. Our production in the Barnett area was also briefly shut-in as a result of the two hurricanes, although the effect was minor. These wells are characterized by steep decline rates in their first year of production (as much as 50% to 60%), followed by a gradual leveling-off of production and a resultant slow decline rate, giving them an overall long production life. Natural gas production in this area is expected to further increase throughout 2005 as we

anticipate drilling twenty wells in this area during 2005. We currently have three rigs running in this area, but expect to add another rig by early 2006.

Our production for the third quarter of 2005 was weighted toward oil (67%), essentially the same oil to natural gas ratio that we have had since the sale of our offshore properties in July 2004. Because of our emphasis on our tertiary operations, we expect that our production will continue to be weighted toward oil in the foreseeable future.

OIL AND NATURAL GAS REVENUES: Oil and natural gas revenues for the third quarter of 2005 increased $35.5 million, or 34%, from revenues in the comparable quarter of 2004, primarily as a result of higher commodity prices, offset in part by lower production primarily due to the effect of the two hurricanes. When comparing the respective nine month periods, revenues increased $43.0 million, or 13%, for the same reasons, partially offset by the lost production as a result of the two hurricanes, coupled with decreased production as a result of the sale of our offshore properties in July 2004. Cash payments on our hedges were $3.8 million in the third quarter of 2005 and $6.6 million for the first nine months of 2005, down from $22.2 million paid in the third quarter of 2004 and $54.8 million during the first nine months of 2004. See Note 5 to the Condensed Consolidated Financial Statements and "Market Risk Management" for additional information regarding our hedging activities.

When comparing the third quarters of 2005 and 2004, the 8% decrease in production caused oil and natural gas revenues to decrease by $8.0 million, or 8%. This decrease was more than offset by the increase in commodity prices, which caused oil and natural gas revenues to increase by $43.5 million, or 42%. For the comparative first nine months of 2005 and 2004, the decrease in production caused oil and natural gas revenues to decrease by $50.6 million, or 15%; however, the increase in commodity prices caused oil and natural gas revenues to increase by $93.6 million, or 28%. Although both oil and natural gas prices were higher in the current year periods than in the 2004 periods, oil prices increased more than natural gas prices. Our realized oil prices (excluding hedges) increased by 47% between the third quarters of 2005 and 2004 and by 42% between the comparable nine month periods, while our realized natural gas prices (excluding hedges) increased by 42% between the third quarters of 2005 and 2004 and by 19% between the comparable nine month periods. On a combined BOE basis, commodity prices were 46% higher for the comparative third quarters and 33% higher for the comparative first nine months of 2005 and 2004.

Our net realized oil prices (excluding hedges) relative to NYMEX prices were lower in the third quarter and first nine months of 2005 than in the comparable 2004 periods as the NYMEX differential deteriorated significantly during the latter half of 2004, and remained high during most of 2005, particularly for the heavy, sour crude (which predominately applies to our Eastern Mississippi production). Our average oil NYMEX differential for the third quarter of 2005 was approximately $6.34 per Bbl, similar to the $6.48 per Bbl NYMEX differential in the fourth quarter of 2004, but worse than the $5.19 per Bbl differential in the third quarter of 2004 and an average of $4.94 per Bbl during 2004. While these differentials did narrow somewhat during the second quarter of 2005, during the third quarter of 2005 they returned to a differential similar to that in the fourth quarter of 2004. If market conditions for heavy, sour crude were to remain consistent, we would expect to gradually improve our overall NYMEX discount as the amount of light sweet oil production from our tertiary operations is expected to increase, improving the overall quality of our product mix. However, as evident in 2004, the oil market can change substantially and rapidly and it is difficult to forecast these trends.

Our natural gas differentials also increased this quarter, averaging $0.97 per Mcf below NYMEX, while most prior quarters have generally been near NYMEX prices. The variance increased this quarter, at least in part, due to increasing natural gas prices during the quarter. Since most of our natural gas is sold on

an index price that is set near the first of each month, the variance will increase if NYMEX natural gas prices consistently rise during the quarter. Further, with the actual and anticipated incremental production from the Barnett Shale area, which has usually sold for about $1.00 less than NYMEX prices, we expect that our overall natural gas NYMEX differential will likely increase over time.

PRODUCTION EXPENSES: Our operating expenses increased on both a per BOE basis and in total dollars, primarily due to our emphasis on tertiary operations discussed above. The reduced production as a result of the two hurricanes

further increased our operating costs on a per BOE basis. Operating expenses on our tertiary operations increased from $17.9 million in the first nine months of 2004 to $27.0 million in the comparable period of 2005 (51%) as a result of increased activity at Mallalieu, McComb and Brookhaven Fields. However, with the 35% higher production from these tertiary operations, the percentage increase in operating expenses for our tertiary operations on a per BOE basis was less, increasing from $9.84 per BOE in the first nine months of 2004 to $11.04 per BOE in the first nine months of 2005 (12%). Workover expenses were also higher in the first nine months of 2005 than in the comparable period of 2004, particularly in the second quarter. Adjusted for the properties sold in the offshore sale, during the second quarter alone, workover expenses were approximately $2.0 million higher than during the second quarter of 2004, primarily related to a mechanical failure on one onshore Louisiana well. The balance of cost increases is generally attributable to higher energy and fuel costs to operate the properties, the addition of operating leases on certain facilities and equipment, and general cost inflation in our industry. In general, we expect our operating costs per BOE to remain high and likely increase throughout the next year as we expect to see continued cost inflation throughout our industry, and the operating costs of our tertiary operations are higher than for our other operations and these tertiary operations are becoming more and more significant to us.

Production taxes and marketing expenses generally change in proportion to commodity prices and therefore were higher in the third quarter and first nine months of 2005 than in the comparable 2004 periods. The July 2004 sale of our offshore properties also contributed to an increase in 2005 production taxes and marketing expenses on a per BOE basis as most of our offshore properties were not subject to severance taxes. We recognized $3.0 million of transportation expenses paid to Genesis during the first nine months of 2005 as a result of a change in the way we market a portion of our crude oil that commenced in September 2004. As of September 1, 2004, we ceased selling most of our crude oil at the wellhead to Genesis, choosing rather to use the Genesis pipeline to transport our crude to market where we sell our own crude directly to refineries. Overall, this has increased our aggregate net proceeds on our crude oil sales, and increased our per unit price per barrel; however, the higher sales proceeds are partially offset by the incremental transportation charges.

General and Administrative Expenses

General and administrative ("G&A") expenses increased 44% between the respective third quarters and 42% between the respective first nine months, as set forth below:

	Three Months Ended September 30,		Nine Mo Sept
	2005	2004	2005
Net G&A expense (thousands)			
Gross G&A expenses	$ 17,737	$ 13,562	$ 46,862
State franchise taxes	447	295	1,065
Operator overhead charges	(7,994)	(6,465)	(22,848
Capitalized exploration costs	(1,238)	(1,195)	(3,640
Net G&A expense	$ 8,952	$ 6,197	$ 21,439
Average G&A cost per BOE	$ 3.56	$ 2.27	$ 2.69
Employees as of September 30	433	369	433

Gross G&A expenses increased $4.2 million, or 31%, between the respective third quarters and $8.8 million or 23% between the respective first nine months. These increases are generally attributable to higher compensation costs due to additional employees (54 employees added between December 31, 2004 and September 30, 2005), wage increases and $1.0 million of non-cash compensation expense for the third quarter and $3.1 million for the first nine months of 2005 for the amortization of deferred compensation associated with the issuance of restricted stock to officers and directors in 2004 and 2005 (as compared to $593,000 in the third quarter of 2004). We also incurred approximately $1.6 million to provide food, water, gasoline, power generators, and other essential supplies to our employees and charitable organizations in Mississippi and Louisiana following the hurricanes, of which all but approximately $243,000 was expensed. In addition, we incurred higher professional service and consultant fees primarily related to Sarbanes-Oxley compliance, investigation of hotline reports, audit work, and documentation and testing of our new software system that we began using in January 2005, as well as increased maintenance costs as a result of the change to the new software system. These 2005 increases were offset by

approximately $1.4 million and $2.4 million of employee severance payments paid in 2004 related to the sale of our offshore properties in July 2004 that we expensed in the third quarter and first nine months of 2004, respectively.

The increase in gross G&A was offset by an increase in operator overhead recovery charges in the third quarter and first nine months of 2005. 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 our incremental drilling and development activity during the third quarter and first nine months of 2005, partially offset by the sale of our offshore properties, the amount we recovered as operator overhead charges increased by 24% between the third quarters of 2004 and 2005 and increased by 14% between the first nine months of 2004 and 2005. Capitalized exploration costs decreased slightly between the comparable periods in 2004 and 2005 as a result of the 2004 termination of a

portion of our offshore exploration staff.

The net effect was a 44% increase in net G&A expense between the respective third quarters and a 42% increase between the first nine months of 2005 and 2004. On a per BOE basis, G&A costs increased 57% in the third quarter of 2005 as compared to the level of those costs in third quarter of 2004, and increased 67% between the comparative first nine months of 2004 and 2005, both higher percentage increases than the increase in gross costs, which resulted from lower production caused by the July 2004 sale of our offshore properties and the production lost due to the two hurricanes. Since virtually all the cost of our personnel that worked directly on the offshore properties sold in 2004 was charged to either operations or capitalized, the sale of our offshore properties had minimal impact on net G&A.

Interest and Financing Expenses

	Three Months Ended September 30,		Nine Sep
Amounts in thousands, except per BOE amounts	2005	2004	2005
Cash interest expense	$ 4,658	$ 4,464	$ 13,
Non-cash interest expense	264	304	
Less: Capitalized interest	(415)	-	(1,
Interest expense	$ 4,507	$ 4,768	$ 13,
Interest and other income	$ 716	$ 701	$ 2,
Average net cash interest expense per BOE (1)	$ 1.43	$ 1.38	$ 1
Average interest rate (2)	7.5%	7.3%	7
Average debt outstanding	$ 249,711	$ 243,478	$ 242,

(1) Cash interest expense less capitalized interest less interest and other income on BOE basis.
(2) Includes commitment fees but excludes amortization of discount and debt issue costs.

Interest expense for the first nine months of 2005 decreased from levels in the comparable periods of 2004 primarily due to lower average debt in 2005 as a result of the sale of our offshore properties in July 2004, the proceeds from which were used to retire our bank debt. Interest expense also decreased between the comparable third quarters as we capitalized $415,000 of interest, primarily relating to the construction of our CO2 pipeline to East Mississippi, which more than offset higher interest rates on our bank debt and slightly higher debt levels. As a result of the lower production because of the 2004 offshore sale and production lost as a result of the two hurricanes, interest expense on a per BOE basis was not as positive as it was on an absolute basis.

Depletion, Depreciation and Amortization

Amounts in thousands, except per BOE amounts	Three Months Ended September 30, 2005	2004	Nine Sep 2005
Depletion and depreciation	$ 21,878	$ 18,658	$ 63,4
Depletion and depreciation of CO2 assets	1,311	1,200	3,6
Accretion of asset retirement obligations	435	429	1,2
Depreciation of other fixed assets	716	493	1,8
Total DD&A	$ 24,340	$ 20,780	$ 70,2
DD&A per BOE:			
Oil and natural gas properties	$ 8.87	$ 7.00	$ 8.
CO2 assets and other fixed assets	0.81	0.62	0.
Total DD&A cost per BOE	$ 9.68	$ 7.62	$ 8.

In total, our depletion, depreciation and amortization ("DD&A") rate on a per BOE basis increased 27% between the respective third quarters, primarily due to rising costs and increases in capital spending in the first nine months of 2005. During the first nine months of 2005, we spent approximately $71.2 million on acquisitions, of which approximately $50.1 million was included in our full cost pool, with the balance becoming part of our unevaluated properties. Due to high commodity prices, the acquisition cost per BOE was around $12.00 per BOE, contributing to the higher DD&A rate. In addition, most of our future development cost estimates on our proved undeveloped reserves have been increased to reflect the rising costs in the industry, contributing to the increase in our 2005 DD&A rates over the rates last year. We booked approximately 2.9 MMBbls of minor incremental oil reserves related to our tertiary operations during the first nine months of 2005, less than we may be able to recognize by year-end. 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 significantly change in the future.

Income Taxes

Amounts in thousands, except per BOE amounts and tax rates	Three Months Ended September 30, 2005	2004	
Income tax provision			
Current income tax expense	$ 7,684	$ 18,949	$
Deferred income tax expense (benefit)	12,324	(11,117)	
Total income tax expense	$ 20,008	$ 7,832	$
Average income tax expense per BOE	$ 7.95	$ 2.87	$
Effective tax rate	34.2%	30.0%	

Our income tax provision for the third quarter and first nine months of 2005 was based on an estimated statutory tax rate of 39%, and for the comparable 2004 periods was based on an estimated statutory tax rate of 38%. Our net effective tax rate was lower than our estimated statutory rates due primarily to our enhanced oil recovery ("EOR") tax credits we earn related to our tertiary operations and to a lesser degree to a new manufacturing deduction that became allowable in 2005 for oil and gas producing activities covered by the American Jobs Creation Act of 2004. Our current income tax expense represents anticipated alternative minimum cash taxes. As of December 31, 2004, we had utilized all of our federal tax net operating loss carryforwards, but had an estimated $27.8 million of EOR credits to carryforward. We expect to generate additional net EOR

credits during 2005, although if oil prices remain at current levels or increase further, we may not be able to generate additional credits in future years as these EOR credits phase out if oil prices are above a certain threshold.

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 are discussed above.

	Three Months Ended September 30,		
Per BOE data	2005	2004	
Revenues	$ 55.07	$ 37.78	$
Loss on settlements of derivative contracts	(1.50)	(8.15)	
Lease operating expenses	(10.33)	(7.25)	
Production taxes and marketing expenses	(2.79)	(1.80)	
Production netback	40.45	20.58	
CO2 operating margin	0.78	0.55	
General and administrative expenses	(3.56)	(2.27)	
Net cash interest expense	(1.43)	(1.38)	
Current income taxes and other	(1.52)	(6.57)	
Changes in assets and liabilities relating to operations	(4.40)	5.50	
Cash flow from operations	30.32	16.41	
DD&A	(9.68)	(7.62)	
Deferred income taxes	(4.90)	4.07	
Non-cash hedging adjustments	(3.20)	0.14	
Changes in assets and liabilities and other non-cash items	2.78	(6.30)	
Net income	$ 15.32	$ 6.70	$

MARKET RISK MANAGEMENT

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. The following table presents the carrying and fair values of our debt, along with average interest rates. The fair value of our bank debt is considered to be the same as the carrying value because the interest rate is based on floating short-term interest rates. 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.

	Expected Maturity Dates					
Amounts in thousands	2005-2006	2007	2008	2009	After	C
Variable rate debt:						
Bank debt	$ -	$ -	$ -	$ 20,000	$ -	$
The weighted-average interest rate on the bank debt at September 30, 2005 is 4.9%						
Fixed rate debt:						
7.5% subordinated debt, net of discount, due 2013	$ -	$ -	$ -	$ -	$225,000	$
The interest rate on the subordinated debt is a fixed rate of 7.5%						

We enter into various financial contracts to hedge 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 historically consisted of price floors, collars and fixed price swaps. Historically, we have generally attempted to hedge between 50% and 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, although our hedging percentage may vary relative to our debt levels. For 2005 and beyond, we have hedged significantly less, primarily because of our strong financial position, measured by our low levels of debt relative to our cash flow from operations. When we make a significant acquisition, we have historically attempted 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. We have not made any large acquisitions during the last couple of years, so we do not have any hedges in place at this time for prior acquisitions.

All of the mark-to-market valuations used for our financial derivatives are provided by external sources and are based on prices that are actively quoted. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to

minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. For a full description of our hedging position at September 30, 2005, see Note 5 to the Condensed Consolidated Financial Statements.

Effective January 1, 2005, we elected to de-designate our existing derivative contracts from hedge accounting treatment and to account for them as speculative contracts going forward. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings. This also means that any balance remaining in other comprehensive income as of December 31, 2004 is being amortized over the remaining life of the contracts (2005). During the third quarter of 2005, we recognized total expense relating to our hedge contracts of $11.8 million, consisting of $3.8 of cash payments, $6.2 million of expense relating to a mark-to-market non-cash adjustment, and $1.8 million of expense relating to the amortization of other comprehensive income related to deferred hedge mark-to-market value losses that existed as of December 31, 2004 which are being amortized as the contracts expire during 2005. For the first nine months of 2005, we recognized total expense relating to our hedge contracts of $18.6 million, consisting of $6.6 million of cash payments, $6.5 million of expense relating to a mark-to-market non-cash adjustment and $5.5 million of expense relating to the amortization of other comprehensive income. Information regarding our current hedging positions and historical hedging results is included in Note 5 to the Condensed Consolidated Financial Statements.

At September 30, 2005, our derivative contracts were recorded at their fair value, which was a net liability of approximately $11.4 million, a larger liability than the $6.5 million fair value liability recorded as of December 31, 2004. This change is the result of a decrease in the fair market value of our remaining hedges (i.e. an increased obligation amount) due to an increase in oil and natural gas commodity prices between December 31, 2004 and September 30, 2005, partially offset by the expiration of approximately 75% of our remaining hedge contracts between January 1, 2005 and September 30, 2005.

Based on NYMEX crude oil futures prices at September 30, 2005, oil prices were considerably higher than the floor price of $27.50 per barrel in our hedges, so we would not expect to receive any funds even if oil prices were to drop 10%. Since the oil hedges are puts or price floors, we do not have to make any payments on the hedges regardless of how high oil prices go. Based on NYMEX natural gas futures prices at September 30, 2005, we would expect to make future cash payments of $11.4 million on our natural gas commodity hedges. If natural gas futures prices were to decline by 10%, the amount we would expect to pay under our natural gas commodity hedges would decrease to $9.5 million, and if futures prices were to increase by 10% we would expect to pay $13.3 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, 2004.

RECENT ACCOUNTING PRONOUNCEMENTS

On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), which is a revision of SFAS No. 123. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) will require all share-based payments to employees, including grants of employee stock options, to be recognized in our Consolidated Statements of Operations based on their estimated fair values. Pro forma disclosure is no longer an alternative.

SFAS No. 123(R) must be adopted at the beginning of our next fiscal year (i.e., January 1, 2006) and permits public companies to adopt its requirements using one of two methods:

- A "modified prospective" method in which compensation cost is recognized based on the requirements of SFAS No. 123(R) for all share-based payments granted prior to the effective date of SFAS No. 123(R) that remain unvested on the adoption date.

- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate either all prior periods presented or prior interim periods of the year of adoption based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures.

As permitted by SFAS No. 123, we currently account for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, we generally do not recognize compensation expense associated with employee stock options. Accordingly, the adoption of SFAS No. 123(R)'s fair value method could have a significant impact on Denbury's future results of operations, although it will have no impact on our overall financial position. We currently plan to adopt the provisions of SFAS No. 123(R) on January 1, 2006 using the modified prospective approach. We have not completed evaluating the impact the adoption of SFAS No. 123(R) will have on our future results of operations.

SFAS No. 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce Denbury's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future; however, it will not have an impact on the Company's overall cash flows.

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, transportation charges, 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 or particular fields, hydrocarbon prices, pricing assumptions based upon current and projected oil and gas prices, liquidity, regulatory matters, mark-to-market values,

competition, long-term forecasts of production, finding costs, rates of return, estimated costs, future capital expenditures and overall economics and other variables surrounding our tertiary operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "anticipate," "projected," "should," "assume," "believe," "target" or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas, inaccurate cost estimates, fluctuations in the prices of goods and services (especially in periods of high demand and/or drilling activity), the uncertainty of drilling results and reserve estimates, operating hazards, acquisition risks,

requirements for capital or its availability, the availability of equipment and personnel, 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

We maintain disclosure controls and procedures and internal controls designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this quarterly report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

In January 2005, we began processing our transactions on a newly implemented accounting software system. We changed systems in order (i) to integrate and automate more of our functions, which will also allow us to have more information in one integrated database, (ii) to provide operating efficiencies, (iii) to enable us to close our books in a more timely manner

without sacrificing quality, (iv) to review and improve our processes and (v) improve the internal control surrounding our computer systems. As a result of moving to a new system in January 2005, certain control procedures are still being changed, documented, and evaluated in order to conform to our new system. While we believe that our new accounting system will ultimately strengthen our internal control system, there are inherent weaknesses in implementing any new system and we are still testing these control changes in order to enable us to provide certification as of year-end of the effectiveness in all material respects of our internal controls over financial reporting that are affected by this new software system. While we have not found any reason to believe that our internal controls over financial reporting are not effective in all material respects, we are continuing to evaluate the impact and effect of a new accounting system on our internal controls and procedures and it is possible that we may find weaknesses in the future.

During 2005, information was reported on our whistleblower hotline regarding misconduct by oilfield vendors and certain employees, including alleged improper billings and payments by certain vendors to, or on behalf of employees, misuse of Company property and operational information, and the failure by employees to report transactions entered into with the Company. At the direction of the audit committee of our board of directors, and in conjunction with outside counsel retained by the Audit Committee, investigations have been undertaken to (1) gain an understanding of both the facts and circumstances surrounding these matters, (2) review our management practices and internal controls as they relate to these areas, (3) ascertain whether, in fact, there were violations of the Company's Code of Conduct and Ethics, (4) make recommendations as to necessary improvements in such practices and controls, and (5) recommend other corrective actions, as deemed appropriate. As a result of our investigations, to date we have dismissed two employees, taken disciplinary action against another employee, and terminated all future business with vendors identified to date as making improper billings and payments. The estimated amount of improper vendor billings and payments discovered to date is inconsequential to our previously issued financial statements and to the financial statements contained in this report on Form 10-Q. We expect to recover a portion of the improper vendor billings from our vendors. We further believe that the ultimate resolution of these matters will not materially adversely affect our financial condition, results of operations or business. We believe that our whistleblower hotline was effective in alerting us to improper vendor and employee conduct and allowing us to remedy the matter.

Controls and policies in place to prevent these occurrences were overridden by employee misconduct in the vendor approval and payment process and in adherence to the Company's Code of Conduct and Ethics. As a result of our

investigation, we plan to implement certain improvements to strengthen our management practices and policies and internal controls, as set forth below:

1. Heighten authorization and documentation requirements for purchasing, including plans to implement a centralized purchasing function;

2. Contact our vendors to inform them of the changes in our procurement practices and pursue their cooperation and assistance in complying with and assisting us in enforcing our new policies;

3. Increase our internal audit reviews in the area of purchasing, bidding, and invoice approval; and

4. Review, refine, emphasize and enforce our Code of Conduct and Ethics

and purchasing policies and procedures with employees and vendors.

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, 2004. There have been no material developments in such legal proceedings since the filing of such Form 10-K.

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum of Shares t Yet Be Pur Under the Pl Programs
July 1 through 31, 2005	-	-	-	
August 1 through 31, 2005	84,574	$ 23.11	-	
September 1 through 30, 2005	-	-	-	
Total	84,574	$ 23.11	-	

The numbers above have been adjusted for the 2-for-1 stock split effective October 31, 2005. These shares were purchased from officers of Denbury who delivered shares to the Company to satisfy their minimum tax withholding requirements related to the vesting of restricted shares that were originally granted in August 2004, as permitted under the Company's 2004 Omnibus Stock and Incentive Plan.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibits:

3(a)*	Certificate of Amendment of Restated Certificate of Incorporation of Denbury Resources Inc. filed with the Delaware Secretary of State on October 20, 2005.
31(a)*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

SIGNATURES

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

DENBURY RESOURCES INC.
(Registrant)

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

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

Date: November 7, 2005

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