DENBURY RESOURCES INC
Form 10-Q
November 08, 2011

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

(Mark One)

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______ to ________

Commission file number: 001-12935

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.)
5320 Legacy Drive Plano, TX	75024
(Address of principal executive offices)	(Zip Code)

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

Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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

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

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

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

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

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

Class	Outstanding at November 1, 2011
Common Stock, $.001 par value	391,624,449

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DENBURY RESOURCES INC.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except par value and share data)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$24,363	$381,869
Accrued production receivable	264,999	223,584
Trade and other receivables, net of allowance of $274 and $456, respectively	176,734	114,149
Short-term investments	81,851	93,020
Derivative assets	116,761	24,242
Deferred tax assets	-	27,454
Total current assets	664,708	864,318
Property and equipment		
Oil and natural gas properties (using full cost accounting)		
Proved	6,763,404	6,042,442
Unevaluated	1,088,733	870,130
CO2 and other non-hydrocarbon gases properties	599,881	523,423
Pipelines and plants	1,598,098	1,378,239
Other property and equipment	142,243	120,641
Less accumulated depletion, depreciation, amortization, and impairment	(2,510,715)	(2,197,517)
Net property and equipment	7,681,644	6,737,358
Derivative assets	56,460	12,919
Goodwill	1,236,094	1,232,418
Other assets	248,027	218,050
Total assets	$9,886,933	$9,065,063
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	$405,243	$350,068
Oil and gas production payable	183,521	143,145
Derivative liabilities	9,253	78,184
Current maturities of long-term debt	8,177	7,948
Deferred taxes	37,326	-
Total current liabilities	643,520	579,345
Long-term liabilities		
Long-term debt, net of current portion	2,396,549	2,416,208
Asset retirement obligations	87,725	81,290
Derivative liabilities	732	29,687
Deferred taxes	1,799,793	1,547,992
Other liabilities	22,842	29,834
Total long-term liabilities	4,307,641	4,105,011
Commitments and contingencies (Note 7)		

Stockholders' equity		
Preferred stock, $.001 par value, 25,000,000 shares authorized, none issued and outstanding	-	-
Common stock, $.001 par value, 600,000,000 shares authorized; 402,625,687 and 400,291,033 shares issued, respectively	403	400
Paid-in capital in excess of par	3,085,862	3,045,937
Retained earnings	1,856,868	1,336,142
Accumulated other comprehensive loss	(7,361)	(488)
Treasury stock, at cost, 0 and 78,524 shares, respectively	-	(1,284)
Total stockholders' equity	4,935,772	4,380,707
Total liabilities and stockholders' equity	$9,886,933	$9,065,063

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues and other income				
Oil, natural gas, and related product sales	$565,523	$460,785	$1,662,814	$1,279,699
CO2 sales and transportation fees	6,541	4,653	16,808	13,840
Gain on sale of interests in Genesis	-	(3)	-	101,537
Interest income and other income	4,441	1,268	12,445	7,658
Total revenues and other income	576,505	466,703	1,692,067	1,402,734
Expenses				
Lease operating expenses	136,531	131,768	393,560	355,731
Production taxes and marketing expenses	36,949	35,542	109,388	92,959
CO2 discovery and operating expenses	1,358	2,488	5,381	5,537
General and administrative	28,906	37,115	103,652	101,016
Interest, net of amounts capitalized of $17,853, $10,917, $42,004 and $56,079, respectively	37,617	53,331	128,643	123,230
Depletion, depreciation, and amortization	101,978	111,602	299,067	322,683
Derivatives expense (income)	(210,154)	31,854	(212,308)	(138,045)
Loss on early extinguishment of debt	-	-	16,131	-
Transaction and other costs related to the Encore Merger	-	11,470	4,377	79,253
Total expenses	133,185	415,170	847,891	942,364
Income before income taxes	443,320	51,533	844,176	460,370
Income tax provision (benefit)				
Current income taxes	(5,331)	3,704	5,849	11,314
Deferred income taxes	172,981	16,595	317,601	167,289
Consolidated net income	275,670	31,234	520,726	281,767
Less: net income attributable to noncontrolling interest	-	(2,130)	-	(20,408)
Net income attributable to Denbury stockholders	$275,670	$29,104	$520,726	$261,359
Net income per common share				
Basic	$0.69	$0.07	$1.31	$0.72
Diluted	$0.68	$0.07	$1.29	$0.71
Weighted average common shares outstanding				
Basic	399,040	395,913	398,371	362,241
Diluted	403,311	401,093	403,575	367,434

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities		
Consolidated net income	$520,726	$281,767
Adjustments needed to reconcile to net cash provided by operating activities		
Depletion, depreciation, and amortization	299,067	322,683
Deferred income taxes	317,601	167,289
Gain on sale of interests in Genesis	-	(101,537)
Stock-based compensation	27,520	27,326
Non-cash fair value derivative adjustments	(217,092)	(185,009)
Loss on early extinguishment of debt	16,131	-
Other, net	9,024	14,254
Changes in operating assets and liabilities		
Accrued production receivable	(45,017)	48,453
Trade and other receivables	(53,012)	20,548
Other assets	2,818	1,106
Accounts payable and accrued liabilities	(65,407)	8,257
Oil and natural gas production payable	40,819	10,553
Other liabilities	(14,086)	(22,915)
Net cash provided by operating activities	839,092	592,775
Cash flows used for investing activities		
Oil and natural gas capital expenditures	(741,256)	(500,062)
Acquisitions of oil and natural gas properties	(34,291)	(24,390)
Cash paid in Encore Merger, net of cash acquired	-	(813,894)
Cash paid in Riley Ridge acquisition	(199,233)	-
CO2 and other non-hydrocarbon gases capital expenditures	(65,866)	(67,328)
Pipelines and plants capital expenditures	(142,406)	(169,157)
Net proceeds from sales of oil and natural gas properties	47,598	909,986
Net proceeds from sale of interests in Genesis	-	162,619
Other	(22,798)	(17,927)
Net cash used for investing activities	(1,158,252)	(520,153)
Cash flows from financing activities		
Bank repayments	(255,000)	(1,519,000)
Bank borrowings	365,000	1,229,000
Repayment of senior subordinated notes	(525,000)	(609,424)
Premium paid on repayment of senior subordinated notes	(13,137)	(7,213)
Net proceeds from issuance of senior subordinated notes	400,000	1,000,000
Net proceeds from issuance of common stock	12,348	8,614
Costs of debt financing	(13,104)	(76,232)
ENP distributions to noncontrolling interest	-	(24,513)
Other	(9,453)	(8,100)
Net cash used for financing activities	(38,346)	(6,868)

Net increase (decrease) in cash and cash equivalents	(357,506)	65,754
Cash and cash equivalents at beginning of period	381,869	20,591
Cash and cash equivalents at end of period	$24,363	$86,345

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Consolidated net income	$275,670	$31,234	$520,726	$281,767
Other comprehensive income, net of income tax				
Net unrealized loss on available-for-sale securities, net of tax benefit of $2,420 and $4,244, respectively	(3,949)	-	(6,925)	-
Interest rate lock derivative contracts reclassified to income, net of tax of $11, $11, $32, and $32, respectively	17	17	52	52
Change in deferred hedge loss on interest rate swaps, net of tax benefit of $14 and $32, respectively	-	(68)	-	(155)
Consolidated comprehensive income	271,738	31,183	513,853	281,664
Less: comprehensive income attributable to noncontrolling interest	-	(2,074)	-	(20,308)
Comprehensive income attributable to Denbury stockholders	$271,738	$29,109	$513,853	$261,356

See accompanying Notes to Unaudited Condensed Consolidated Financial Statements.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Basis of Presentation

Organization and Nature of Operations

We are a growing independent oil and natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest reserves of CO_2 used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with our most significant emphasis on our CO_2 tertiary recovery operations.

Interim Financial Statements

The accompanying unaudited condensed consolidated financial statements of Denbury Resources Inc. and its subsidiaries have been prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and do not include all of the information and footnotes required by Accounting Principles Generally Accepted in the United States ("U.S. GAAP") for complete financial statements. 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, 2010. Unless indicated otherwise or the context requires, the terms "we," "our," "us," or "Denbury," refer to Denbury Resources Inc. and its subsidiaries.

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 year. In management's opinion, the accompanying unaudited condensed consolidated financial statements include all adjustments of a normal recurring nature necessary for a fair statement of our consolidated financial position as of September 30, 2011, our consolidated results of operations for the three and nine months ended September 30, 2011 and 2010, and our consolidated cash flows for the nine months ended September 30, 2011 and 2010. Certain prior period items have been reclassified to make the classification consistent with the classification in the most recent quarter.

Noncontrolling Interest

From March 9, 2010 to December 31, 2010, we owned approximately 46% of Encore Energy Partners LP ("ENP") outstanding common units and 100% of Encore Energy Partners GP LLC ("GP LLC"), which was ENP's general partner. Considering the presumption of control of GP LLC in accordance with the Consolidation topic of the Financial Accounting Standards Board Codification ("FASC"), the results of operations and cash flows of ENP were consolidated with those of Denbury for this period. On December 31, 2010, we sold all of our ownership interests in ENP and, therefore, we did not consolidate ENP in our Unaudited Condensed Consolidated Balance Sheet as of December 31, 2010. As presented in the Unaudited Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2010, "Net income attributable to noncontrolling interest" of $2.1 million and $20.4 million, respectively, represents ENP's results of operations attributable to third-party ENP limited partner interest owners, other than Denbury, for the portion of that period for which we consolidated ENP.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income attributable to our stockholders 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 of the potential dilution from stock options, stock appreciation rights ("SARs"), unvested restricted stock, and unvested performance equity awards. For the three and nine months ended September 30, 2011 and 2010, there were no adjustments to net income attributable to our stockholders 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 periods indicated:

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Notes to Unaudited Condensed Consolidated Financial Statements

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2011	2010	2011	2010
Basic weighted average common shares	399,040	395,913	398,371	362,241
Potentially dilutive securities:				
Stock options and SARs	2,954	3,647	3,818	3,772
Performance equity awards	41	292	22	305
Restricted stock	1,276	1,241	1,364	1,116
Diluted weighted average common shares	403,311	401,093	403,575	367,434

Basic weighted average common shares excludes 3.4 million and 3.5 million shares for the three and nine months ended September 30, 2011, respectively, and 3.4 million and 3.3 million shares for the three and nine months ended September 30, 2010, respectively, of unvested restricted stock. As these restricted shares vest or become retirement eligible, they will be included in the shares outstanding used to calculate basic net income per common share, although all restricted stock is issued and outstanding upon grant. For purposes of calculating diluted weighted average common shares, unvested restricted stock is included in the computation using the treasury stock method, with the deemed proceeds equal to the average unrecognized compensation during the period, adjusted for any estimated future tax consequences recognized directly in equity.

The following securities could potentially dilute earnings per share in the future, but were excluded from the computation of diluted net income per share as their effect would have been anti-dilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2011	2010	2011	2010
Stock options and SARs	4,731	4,270	3,108	4,613
Restricted stock	139	69	56	298

Short-term Investments

Short-term investments are available-for-sale securities recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. At September 30, 2011 and December 31, 2010, short-term investments consisted entirely of our investment in Vanguard Natural Resources LLC (“Vanguard”) common units obtained as partial consideration for the sale of our interests in ENP to a subsidiary of Vanguard on December 31, 2010. The cost basis of this investment is $93.0 million. We received distributions of $1.8 million and $5.3 million on the Vanguard common units we own for the three and nine months ended September 30, 2011, respectively, which distributions are included in “Interest income and other income” on our Unaudited Condensed Consolidated Statements of Operations. The unrealized loss on our short-term investment of $3.9 million (net of a tax benefit of $2.4 million) and $6.9 million (net of a tax benefit of $4.2 million) for the three and nine months ended September 30, 2011, respectively, is included in our Unaudited Condensed Consolidated Statements of Comprehensive Operations.

Recently Issued Accounting Pronouncements

In September 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2011-08, Testing Goodwill for Impairment, (“ASU 2011-08”). ASU 2011-08 amends the FASC Intangibles – Goodwill and Other topic by permitting entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test described in the FASC Intangibles – Goodwill and Other topic. We adopted ASU 2011-08 and will apply the guidance prospectively to interim and annual goodwill impairment tests.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income, (“ASU 2011-05”). ASU 2011-05 requires the presentation of comprehensive income in either 1) a continuous statement of comprehensive income or 2) two separate but consecutive statements. ASU 2011-05 will be effective for our fiscal year beginning January 1, 2012. Since ASU 2011-05 will only amend presentation requirements, it will not have a material effect on our consolidated financial statements.

In May 2011, the FASB issued ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, (“ASU 2011-04”). ASU 2011-04 amends the FASC Fair Value Measurements topic by providing a consistent definition and measurement of fair value, as well as similar disclosure requirements between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles, clarifies the application of existing fair value measurements and expands the fair value disclosure requirements, particularly for Level 3 fair value measurements. ASU 2011-04 will be effective for our fiscal year beginning January 1, 2012. The adoption of ASU 2011-04 is not expected to have a material effect on our consolidated financial statements, but may require additional disclosures.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 2. Acquisitions and Divestitures

Acquisitions

October 2010 and August 2011 Acquisitions of Reserves in Rocky Mountain Region at Riley Ridge

In October 2010, we acquired a 42.5% non-operated working interest in the Riley Ridge Federal Unit ("Riley Ridge"), located in the LaBarge Field of southwestern Wyoming, for $132.3 million after closing adjustments. Riley Ridge contains natural gas resources, as well as helium and CO2 resources. The purchase included a 42.5% interest in a gas plant, currently under construction, which will separate the helium and natural gas from the commingled gas stream. The acquisition also included approximately 33% of the CO2 mineral rights in an additional 28,000 acres adjoining the Riley Ridge Unit. The fair values assigned to assets acquired and liabilities assumed in the October 2010 acquisition have been finalized and no adjustments have been made to amounts previously disclosed in our Form 10-K for the period ended December 31, 2010.

On August 1, 2011, we acquired the remaining 57.5% working interest in Riley Ridge not already owned, the remaining 57.5% interest in the gas plant and a working interest of approximately 33% in the 28,000 acres adjacent to Riley Ridge. As a result of the transaction, we became the operator of both projects. The purchase price was approximately $214.6 million after preliminary closing adjustments, including a $15 million deferred payment to be made at the time the property's gas plant is operational and meets specific performance conditions. We expect the gas plant to be operational during the latter part of the first quarter of 2012.

Because the Riley Ridge plant is currently under construction, current production at the field is negligible. As a result, pro forma information has not been disclosed due to the immateriality of revenues and expenses during 2011 and 2010.

The August 1, 2011 acquisition of Riley Ridge meets the definition of a business under the FASC Business Combinations topic. The following table presents a summary of the fair value of the Riley Ridge assets acquired and liabilities assumed on August 1, 2011:

In thousands	
Consideration:	
Cash payment	$199,554
Deferred payment(1)	15,000
Total consideration	214,554
Less: Fair value of assets and liabilities acquired:(2)	
Oil and natural gas properties	
Proved	48,731
Unevaluated	12,542
CO2 and other non-hydrocarbon gases properties	9,741
Pipelines and plants	91,594
Other assets(3)	48,660
Asset retirement obligations	(389)
	210,879

Goodwill	$3,675

(1) The deferred payment is included in "Accounts payable and accrued liabilities" on the accompanying balance sheet and will be paid at the time the property's gas plant is operational and meets specific performance conditions as described above.
(2) Fair value of the assets acquired and liabilities assumed is preliminary, pending final closing adjustments.
(3) Other assets includes helium extraction rights of $36.7 million. Helium reserves at Riley Ridge are owned primarily by the Federal government. The fair value assigned to helium extraction rights was calculated using the income approach and represents the future net revenues associated with the Company's right to extract and sell the helium on behalf of the helium resource owners. Upon commencement of helium production, helium extraction rights will be amortized on a units-of-production basis.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

2010 Merger with Encore Acquisition Company

On March 9, 2010, we acquired Encore Acquisition Company ("Encore") pursuant to the Encore Merger Agreement entered into with Encore on October 31, 2009. The Encore Merger Agreement provided for a stock and cash transaction valued at approximately $4.8 billion at the acquisition date, including the assumption of debt and the value of the noncontrolling interest in ENP (the "Encore Merger"). Under the Encore Merger Agreement, Encore was merged with and into Denbury, with Denbury surviving the Encore Merger.

For the three months ended September 30, 2010 and for the period from March 9, 2010 to September 30, 2010, we recognized $174.3 million and $435.2 million, respectively, of oil, natural gas sales and related product sales from properties acquired as part of the Encore Merger. For the three months ended September 30, 2010 and for the period from March 9, 2010 to September 30, 2010, we recognized $114.1 million and $294.8 million, respectively, of net field operating income (oil, natural gas and related product sales less lease operating expenses, production taxes and marketing expenses) from properties acquired as part of the Encore Merger. We recognized a total of $11.5 million of transaction and other costs related to the Encore Merger (primarily advisory, legal, accounting, due diligence, integration and severance costs) for the three months ended September 30, 2010, and $4.4 million and $79.3 million of such costs for the nine months ended September 30, 2011 and 2010, respectively.

Pro Forma Information

Had the Encore Merger occurred on January 1, 2010, our combined pro forma revenues and net income for the three and nine months ended September 30, 2010, would have been as follows:

	Pro Forma Results	
In thousands, except per share amounts	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Pro forma total revenues	$ 466,703	$ 1,579,184
Pro forma net income attributable to Denbury stockholders	29,104	276,527
Pro forma net income per common share:		
Basic	$ 0.07	$ 0.70
Diluted	0.07	0.69

Divestitures

2010 Sale of Interests in Genesis

In February 2010, we sold our interest in Genesis Energy, LLC, the general partner of Genesis Energy, L.P. ("Genesis"), for net proceeds of approximately $84 million. In March 2010, we sold all of our Genesis common units in a secondary public offering for net proceeds of approximately $79 million. We recognized a pre-tax gain of approximately $101.5 million ($63.0 million after tax) on these dispositions.

2010 Sales of Non-Strategic Legacy Encore Properties

In May 2010, we sold certain non-strategic legacy Encore properties, primarily located in the Permian Basin, the Mid-continent area and the East Texas Basin (the "Southern Assets"), to Quantum Resources Management, LLC for consideration of $892.1 million after closing adjustments. In August 2010, we sold additional legacy Encore properties, primarily located in the Cleveland Sand Play of western Oklahoma, for consideration of $32.1 million after closing adjustments. We did not record a gain or loss on the sales in accordance with the full cost method of accounting.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 3. Long-Term Debt

The following table shows the components of our long-term debt:

In thousands	September 30, 2011	December 31, 2010
Bank Credit Agreement	$110,000	$-
7½% Senior Subordinated Notes due 2013, including discount of $437	-	224,563
7½% Senior Subordinated Notes due 2015, including premium of $427	-	300,427
9½% Senior Subordinated Notes due 2016, including premium of $12,538 and $14,589, respectively	237,458	239,509
9¾% Senior Subordinated Notes due 2016, including discount of $18,925 and $22,139, respectively	407,425	404,211
8¼% Senior Subordinated Notes due 2020	996,273	996,273
6 % Senior Subordinated Notes due 2021	400,000	-
Other Subordinated Notes, including premium of $35 and $41, respectively	3,841	3,848
NEJD Pipeline financing	164,626	167,331
Free State Pipeline financing	80,093	81,188
Capital lease obligations	5,010	6,806
Total	2,404,726	2,424,156
Less current obligations	(8,177)	(7,948)
Long-term debt and capital lease obligations	$2,396,549	$2,416,208

The parent company, Denbury Resources Inc. ("DRI"), is the sole issuer of all of our outstanding senior subordinated notes. DRI has no independent assets or operations. Each of the subsidiary guarantors is 100% owned by DRI; any subsidiaries of DRI other than the subsidiary guarantors are minor subsidiaries, and the subsidiary guarantors fully and unconditionally guarantee our senior subordinated debt jointly and severally.

Bank Credit Agreement

In March 2010, we entered into a $1.6 billion revolving credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and other lenders as party thereto (the "Bank Credit Agreement"). Availability under the Bank Credit Agreement is subject to a borrowing base which is redetermined semi-annually on or prior to May 1 and November 1 and upon requested special redeterminations. The borrowing base is adjusted at the banks' discretion and is based in part upon external factors over which we have no control. If the borrowing base were to be less than outstanding borrowings under the Bank Credit Agreement, we would be required to repay the deficit over a period of four months.

In May 2011, we entered into the Fifth Amendment to the Bank Credit Agreement (the "Fifth Amendment"). The Fifth Amendment extends the maturity of the Bank Credit Agreement from March 2014 to May 2016, reduces the applicable margin on outstanding borrowings, reduces the letter of credit fee and adjusts the maximum permitted ratio of debt to adjusted EBITDA. Under the Fifth Amendment, the margin on outstanding Eurodollar loans bears interest at the Eurodollar rate (as defined in the Bank Credit Agreement) plus the applicable margin of 1.5% to 2.5%

(previously 2.0% to 3.0%) based on the ratio of outstanding borrowings to the borrowing base, and the base rate loans bear interest at the base rate (as defined in the Bank Credit Agreement) plus the applicable margin of 0.5% to 1.5% (previously 1.0% to 1.5%) based on the ratio of outstanding borrowings to the borrowing base. The Fifth Amendment also prescribes a commitment fee ranging between 0.375% and 0.5% on the unused portion of the credit facility or if less, the borrowing base, and adjusts the maximum permitted ratio of debt to adjusted EBITDA of Denbury and its subsidiaries from 4.0x to 4.25x.

In September 2011, we entered into the Sixth Amendment to the Bank Credit Agreement (the "Sixth Amendment"). The Sixth Amendment permits Denbury to make distributions to its equity holders, including specifically repurchase of its common stock and/or making cash dividends with respect thereto, in an aggregate amount of up to $500 million during the term of the Credit Facility, subject to certain restrictions, including pro forma availability of no less than 25% of the borrowing base at the time of any such transactions. The Sixth Amendment provides us the flexibility to repurchase our common stock and/or pay cash dividends (within the $500 million limit) from time to time as deemed appropriate by, and subject to pre-approval of, our Board of Directors. Also in September 2011, the banks reaffirmed our borrowing base of $1.6 billion under the Bank Credit Agreement until the next scheduled redetermination in May 2012.

6 % Senior Subordinated Notes due 2021

In February 2011, we issued $400 million of 6 % Senior Subordinated Notes due 2021 ("2021 Notes"). The 2021 Notes, which carry a coupon rate of 6.375%, were sold at par. The net proceeds of $393 million were used to repurchase a portion of our outstanding 2013 Notes and 2015 Notes (see Redemption of our 2013 and 2015 Notes below).

The 2021 Notes mature on August 15, 2021, and interest is payable on February 15 and August 15 of each year, beginning August 15, 2011. We may redeem the 2021 Notes in whole or in part at our option beginning August 15, 2016 at the following redemption prices: 103.188% on or after August 15, 2016; 102.125% on or after August 15, 2017; 101.062% on or after August 15, 2018; and 100% on or after August 15, 2019. Prior to August 15, 2014, we may, at our option, redeem up to an aggregate of 35% of the principal amount of the 2021 Notes at a price of 106.375% with the proceeds of certain equity offerings. In addition, at any time prior to August 15, 2016, we may redeem 100% of the principal amount of the 2021 Notes at a price equal to 100% of the principal amount plus a "make-whole" premium and accrued and unpaid interest. The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. The 2021 Notes are not subject to any sinking fund requirements. All of our subsidiaries, other than minor subsidiaries, fully and unconditionally guarantee this debt jointly and severally.

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Redemption of our 2013 and 2015 Notes

On February 3, 2011, we commenced cash tender offers to purchase all $225.0 million principal amount of our 2013 Notes and all $300.0 million principal amount of our 2015 Notes. Upon expiration of the tender offers on March 3, 2011, we accepted for purchase $169.6 million in principal of the 2013 Notes at 100.625% of par, and $220.9 million in principal of the 2015 Notes at 104.125% of par. We called the remaining 2013 and 2015 Notes, repurchasing all of the remaining outstanding 2015 Notes ($79.1 million) at 103.75% of par on March 21, 2011 and all of the remaining outstanding 2013 Notes ($55.4 million) at par on April 1, 2011. We recognized a $16.1 million loss during the nine months ended September 30, 2011 associated with the debt repurchases, which is included in our Unaudited Condensed Consolidated Statements of Operations under the caption "Loss on early extinguishment of debt".

Note 4. Derivative Instruments

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

From time to time, we enter into various oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance, as we believe it is important to protect our future cash flow to provide a level of assurance for our capital spending in those future periods in light of current worldwide economic uncertainties and commodity price volatility.

We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. All of our commodity derivative contracts are with parties that are lenders under our Bank Credit Agreement.

The following is a summary of "Derivatives expense (income)" included in the accompanying Unaudited Condensed Consolidated Statements of Operations for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2011	2010	2011	2010
Oil				
Payment on settlements of derivative contracts	$1,857	$3,590	$23,857	$80,969
Fair value adjustments to derivative contracts - expense (income)	(205,355)	62,450	(225,485)	(144,471)
Total derivative expense (income) - oil	(203,498)	66,040	(201,628)	(63,502)
Natural Gas				
Receipt on settlements of derivative contracts	(6,427)	(13,626)	(19,073)	(34,005)

Fair value adjustments to derivative contracts - expense (income)	(229)	(19,933)	8,393	(39,041)
Total derivative expense (income) - natural gas	(6,656)	(33,559)	(10,680)	(73,046)
Ineffectiveness on interest rate swaps	-	(627)	-	(1,497)
Derivative expense (income)	$(210,154)	$31,854	$(212,308)	$(138,045)

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Commodity Derivative Contracts Not Classified as Hedging Instruments

The following tables present outstanding commodity derivative contracts with respect to future production as of September 30, 2011:

				NYMEX Contract Prices Per Bbl		
				Weighted Average Price		
Year	Months	Type of Contract	Bbls/d	Swap	Floor	Ceiling
Oil Contracts						
2011	Oct - Dec	Swap	625	$ 79.18	$ -	$ -
		Collar	45,500	-	70.33	101.74
		Put	6,625	-	69.53	-
	Total Oct - Dec 2011		52,750			
2012	Jan - Mar	Swap	625	81.04	-	-
		Collar	52,000	-	70.00	106.86
		Put	625	-	65.00	-
	Total Jan - Mar 2012		53,250			
	Apr-June	Swap	625	81.04	-	-
		Collar	53,000	-	70.00	119.44
		Put	625	-	65.00	-
	Total Apr - June 2012		54,250			
	July-Sept	Swap	625	81.04	-	-
		Collar	53,000	-	80.00	128.57
		Put	625	-	65.00	-
	Total July - Sept 2012		54,250			
	Oct - Dec	Swap	625	81.04	-	-
		Collar	53,000	-	80.00	128.57
		Put	625	-	65.00	-
	Total Oct - Dec 2012		54,250			
2013	Jan - Mar	Collar	16,000	-	70.00	112.66
	Total Jan - Mar 2013		16,000			

Year	Months	Type of Contract	MMBtu/d	Weighted Average Swap Price per MMBtu

Natural Gas Contracts					
2011	Oct - Dec	Swap	33,500	$	6.27
		Total Oct - Dec 2011	33,500		
2012	Jan - Dec	Swap	20,000		6.53
		Total Jan - Dec 2012	20,000		

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Additional Disclosures about Derivative Instruments

At September 30, 2011 and December 31, 2010, we had derivative financial instruments recorded in our Unaudited Condensed Consolidated Balance Sheets as follows:

		Estimated Fair Value Asset (Liability)	
In thousands		September 30,	December 31,
Type of Contract	Balance Sheet Location	2011	2010
Derivatives not designated as hedging instruments:			
Derivative asset			
Oil contracts	Derivative assets - current	$96,177	$3,050
Natural gas contracts	Derivative assets - current	20,584	21,192
Oil contracts	Derivative assets - long-term	52,627	1,301
Natural gas contracts	Derivative assets - long-term	3,833	11,618
Derivative liability			
Oil contracts	Derivative liabilities - current	(60)	(55,256)
Deferred premiums	Derivative liabilities - current	(9,193)	(22,928)
Oil contracts	Derivative liabilities - long-term	(70)	(25,906)
Deferred premiums	Derivative liabilities - long-term	(662)	(3,781)
Total derivatives not designated as hedging instruments		$163,236	$(70,710)

Note 5. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The FASC establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

- Level 1 - Quoted prices in active markets for identical assets or liabilities as of the reporting date.

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

- Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Instruments in this category include non-exchange-traded natural gas derivatives swaps that are based on regional pricing other than NYMEX (e.g., Houston Ship Channel).

We adjust the valuations for nonperformance risk, using our estimate of the counterparty's credit quality for asset positions and Denbury's credit quality for liability positions. We use multiple sources of third-party credit data in determining counterparty nonperformance risk, including credit default swaps.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of the periods indicated:

	Fair Value Measurements Using:			
In thousands	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
September 30, 2011				
Assets				
Short-term investments	$81,851	$-	$ -	$81,851
Oil and natural gas derivative contracts	-	166,244	6,977	173,221
Liabilities				
Oil and natural gas derivative contracts	-	(130)	-	(130)
Total	$81,851	$166,114	$ 6,977	$254,942
December 31, 2010				
Assets				
Short-term investments	$93,020	$-	$ -	$93,020
Oil and natural gas derivative contracts	-	20,683	16,478	37,161
Liabilities				
Oil and natural gas derivative contracts	-	(81,162)	-	(81,162)
Total	$93,020	$(60,479)	$ 16,478	$49,019

The following table summarizes the changes in the fair value of our Level 3 assets for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2011	2010	2011	2010
Balance, beginning of period	$6,638	$40,283	$16,478	$-
Unrealized gains (losses) on commodity derivative contracts included in earnings	1,717	20,103	(5,359)	35,002
Commodity derivative contracts acquired from Encore	-	-	-	38,093
Receipts on settlement of commodity derivative contracts	(1,378)	(9,035)	(4,142)	(21,744)
Balance, end of period	$6,977	$51,351	$6,977	$51,351

Since we do not use hedge accounting for our commodity derivative contracts, any gains and losses on our assets and liabilities are included in “Derivatives expense (income)” in the accompanying Unaudited Condensed Consolidated Statements of Operations.

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DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Unaudited Condensed Consolidated Financial Statements. See Note 3, Long-Term Debt and Item 3, Quantitative and Qualitative Disclosures about Market Risk for further information about these financial instruments.

	September 30, 2011		December 31, 2010	
In thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
7½% Senior Subordinated Notes due 2013	$-	$-	$224,563	$228,375
7½% Senior Subordinated Notes due 2015	-	-	300,427	310,500
9½% Senior Subordinated Notes due 2016	237,458	242,914	239,509	249,661
9¾% Senior Subordinated Notes due 2016	407,425	460,458	404,211	475,380
8¼% Senior Subordinated Notes due 2020	996,273	1,046,087	996,273	1,080,956
6 % Senior Subordinated Notes due 2021	400,000	388,000	-	-

The fair values of our senior subordinated notes are based on quoted market prices. We have other financial instruments consisting primarily of cash, cash equivalents, our Bank Credit Agreement, and short-term receivables and payables that approximate fair value due to the nature of the instrument and the relatively short maturities.

Note 6. Supplemental Information

Accounts Payable and Accrued Liabilities

The following table summarizes our accounts payable and accrued liabilities as of the periods indicated:

In thousands	September 30, 2011	December 31, 2010
Accounts payable	$107,391	$47,660
Accrued exploration and development costs	143,647	101,758
Accrued compensation	27,476	39,757
Accrued lease operating expense	30,005	23,557
Accrued interest	28,957	57,077
Taxes payable	19,214	34,371
Deferred Riley Ridge acquisition consideration	15,000	-
Other	33,553	45,888
Total	$405,243	$350,068

Supplemental Cash Flow Information

The following table sets forth supplemental cash flow information for the periods indicated:

	Nine Months Ended September 30,	
In thousands	2011	2010

Cash paid for interest, expensed	$137,289	$114,012
Cash paid for interest, capitalized	42,004	56,079
Cash paid for income taxes	36,688	13,691
Cash received for income tax refunds	21,990	13,525
Increase in liabilities for capital expenditures	86,769	13,880
Issuance of Denbury common stock in connection with the Encore Merger	-	2,085,681

DENBURY RESOURCES INC.

Notes to Unaudited Condensed Consolidated Financial Statements

Note 7. Commitments and Contingencies

In March 2011, we entered into three long-term supply contracts to purchase CO2 from future anthropogenic sources in the Gulf Coast and Rocky Mountain regions. The three contracts are in addition to the previously disclosed long-term supply contracts Denbury currently has in place in the Gulf Coast, Rocky Mountain and Midwest regions. Under the three new contracts, Denbury will purchase 100% of the CO2 captured from the DKRW Advanced Fuels LLC's Medicine Bow Fuel and Power LLC ("MBFP") project near Medicine Bow, Wyoming, purchase 70% of the CO2 captured from Mississippi Power Company's Kemper County Integrated Gasification Combined Cycle ("Mississippi Power") project in Mississippi, and purchase 100% of the CO2 captured by Air Products LLC ("Air Products") at a third-party refinery in Port Arthur, Texas. These new contracts each have an initial term of 15 to 16 years and include options to extend the term. We estimate that these new sources will supply approximately 365 MMcf/d of CO2 for our enhanced oil recovery operations, although under certain circumstances, we may be obligated to purchase up to 460 MMcf/d, a portion of which would be at a reduced price per Mcf. We expect to begin taking delivery of approximately 100 MMCF/d of CO2 from the MBFP project in 2015, 115 MMcf/d of CO2 from the Mississippi Power project by 2014, and 50 MMcf/d of CO2 from Air Products in late 2012. Our aggregate maximum purchase obligation for CO2 purchased under these three contracts would be approximately $110 million per year (assuming purchases of 460 MMcf/d), plus transportation, assuming a $100 per barrel NYMEX oil price. The purchase price of CO2 will fluctuate based on the changes in the price of oil.

As is the case with all of our long-term supply contracts to purchase CO2, the three agreements entered into in March are subject to various contingencies. The Mississippi Power and Air Products plants are currently being constructed, and the MBFP project is contingent upon securing debt financing, equity commitments and receipt of all necessary consents and approvals.

In conjunction with the August 1, 2011 Riley Ridge acquisition, we assumed the 20-year helium supply contract under which the original participants in Riley Ridge agreed to supply helium to a third party purchaser. Subsequently, we amended this contract to provide for annual delivery (to the 8/8ths working interest) of 127 MMcf of helium (previously 200 MMcf) during the first two years of the contract and thereafter provides for delivery of 400 MMcf of helium per year. If the contracted quantity of helium is not supplied, we are obligated to compensate the third party helium purchaser for the amount of the shortfall in an amount not to exceed $8.0 million per year.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS subsequently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum ("TAM") issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. As a result of the prospective nature of the IRS's determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are subject to review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

We are subject to audits for sales and use taxes and severance taxes in the various states in which we operate, and from time to time receive assessments for potential taxes that we may owe. Currently, we have no material assessments for potential taxes.

We are involved in various lawsuits, claims and other regulatory proceedings incidental to our businesses. While we currently believe that the ultimate outcome of these proceedings, individually and in the aggregate, will not have a material adverse effect on our financial position, results of operations or cash flows, litigation is subject to inherent uncertainties. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that a loss is probable and the amount can be reasonably estimated.

Note 8. Subsequent Event

In early October 2011, we announced the commencement of a common share repurchase program for up to $500 million of Denbury common shares, as approved by the Company's Board of Directors. The program has no pre-established ending date, and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program. Between early October 2011 and October 31, 2011, we repurchased 10,990,939 shares of Denbury common stock (approximately 2.7% of our outstanding shares of common stock at September 30, 2011) for $149.3 million, or $13.58 per share under this share repurchase program.

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DENBURY RESOURCES INC.

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

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and in our Annual Report on Form 10-K for the year ended December 31, 2010, along with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in such Form 10-K. Any terms used but not defined in the following discussion have the same meaning given to them in the Form 10-K. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of Part II of this report, along with Forward-Looking Information at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are a growing independent oil and natural gas company. We are the largest oil and natural gas producer in both Mississippi and Montana, own the largest CO2 reserves used for tertiary oil recovery east of the Mississippi River, and hold significant operating acreage in the Rocky Mountain and Gulf Coast regions. Our goal is to increase the value of acquired properties through a combination of exploitation, drilling and proven engineering extraction practices, with the most significant emphasis on our CO2 tertiary recovery operations.

The acquisition of Encore Acquisition Company (the "Encore Merger") on March 9, 2010, has had a significant impact on nearly every aspect of our business, including oil and natural gas production, revenues and operating expenses. Accordingly, the Encore Merger impacts the comparability of our financial results from the first nine months of 2010 to those in the first nine months of 2011, which is more fully detailed throughout the following discussion and analysis. Our financial results for the first nine months of 2010 include the results of operations of Encore from the date of the acquisition on March 9, 2010 through September 30, 2010. Additionally, starting in May 2010 and throughout the remainder of 2010, we disposed of non-strategic Encore properties and our ownership interests in Encore Energy Partners LP ("ENP").

Third Quarter Operating Highlights

We recognized net income of $275.7 million, or $0.69 per basic common share, during the third quarter of 2011 as compared to net income of $29.1 million, or $0.07 per basic common share, during the third quarter of 2010. This increase between the two periods is primarily attributable to:

- incremental income of $248.1 million ($153.8 million after tax) attributable to the non-cash increase in the fair value of the Company's commodity derivative contracts, principally due to the change in NYMEX oil futures prices; and

- an increase in revenue of $104.7 million ($64.9 million after tax), or 23%, as a result of higher commodity prices, partially offset by lower production as a result of asset sales in late 2010.

During the third quarter of 2011, our oil and natural gas production, which was 93% oil, averaged 66,830 BOE/d as compared to 77,730 BOE/d produced during the third quarter of 2010. This drop in production is primarily attributable to the fourth quarter of 2010 sale of our Haynesville natural gas assets and our interests in ENP. After adjusting third quarter 2010 production to exclude production from properties which were sold in the fourth quarter of

2010, continuing production in the third quarter of 2011 increased 6% over production in the comparable prior year quarter. This production increase was primarily attributable to increases in our Bakken and tertiary oil production in the most recent quarter. Our tertiary oil production averaged 31,091 Bbls/d during the third quarter of 2011, up 5% over the 29,531 Bbls/d produced during the third quarter a year earlier and up 1%, or 320 Bbls/d, over second quarter 2011 levels. Our Bakken oil production averaged 9,976 BOE/d during the third quarter of 2011, an increase of 114% over production of 4,657 BOE/d during the third quarter of 2010 and sequentially up 2,350 BOE/d or 31% from levels in the second quarter of 2011. See Results of Operations — CO2 Operations and Results of Operations — Operating Results — Production for more information.

Oil prices received during the third quarter of 2011 were considerably higher than prices received during the third quarter of 2010. Our average oil and natural gas price received per BOE, excluding the impact of commodity derivative contracts, was $91.98 per BOE during the third quarter of 2011, compared to $64.44 per BOE during the third quarter of 2010, a 43% increase between the comparative third quarter periods. During the third quarter of 2011, our oil price differentials (our received net oil price compared to NYMEX West Texas Intermediate ("WTI") prices) improved by $11.10 per Bbl, from a negative $3.85 per Bbl in the third quarter of 2010 to a positive $7.25 per Bbl in the third quarter of 2011, primarily due to the favorable price differential for our crude oil sold under Louisiana Light Sweet ("LLS") index pricing. See Results of Operations – Operating Results – Oil and Natural Gas Revenues below for more information.

August 2011 Acquisition of Remaining Working Interest in Riley Ridge

On August 1, 2011, we acquired the remaining 57.5% working interest that we did not already own in the Riley Ridge Federal Unit ("Riley Ridge"), the remaining 57.5% interest in the gas plant and a working interest of approximately 33% in the 28,000 acres adjacent to Riley Ridge. As a result of the transaction, we became the operator of both projects. The purchase price after preliminary closing adjustments was approximately $214.6 million, which includes a $15 million deferred payment to be made at the time the property's gas plant is operational and meets specific performance conditions. We currently expect the gas plant to be operational with the first production of natural gas and helium from Riley Ridge during the latter part of the first quarter of 2012. The CO2will be re-injected into the reservoir until we have completed an additional separation facility and a CO2pipeline to the field, which is expected to be completed in 2016.

Combining this acquisition with the interests in Riley Ridge that we acquired in October 2010, we estimate that, as of September 30, 2011, our total ownership at Riley Ridge contains estimated proved reserves of 431 Bcf of natural gas, 15.3 Bcf of helium and 2.2 Tcf of CO2. The adjacent 28,000 acres is estimated to contain additional probable reserves of 250 to 300 Bcf of natural gas, 9.5 to 11.5 Bcf of helium and 2.0 to 2.2 Tcf of CO2, net to our interest. These estimates of potential reserves, which include estimates of probable reserves based on the most recent drilling and technical data available, are more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering these reserves is subject to substantially greater risk.

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DENBURY RESOURCES INC.

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

Addition of Proved Oil and Natural Gas Reserves

We added 83.0 MMBOE of estimated proved reserves during the first nine months of 2011, including 52.1 MMBOE of estimated proved reserves during the third quarter of 2011. The third quarter 2011 reserve additions include 237 Bcf (39.5 MMBOE) in fields in the Riley Ridge acquisition completed in August, which is discussed above, 11.6 MMBOE in our Bakken properties, and minor revisions to our other properties.

Recent Common Share Repurchase Program

In early October 2011, we announced the commencement of a common share repurchase program for up to $500 million of Denbury common shares, as approved by the Company's Board of Directors. The program has no pre-established ending date, and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program. Between early October 2011 and October 31, 2011, we repurchased 10,990,939 shares of Denbury common stock (approximately 2.7% of our outstanding shares of common stock at September 30, 2011) for $149.3 million, or $13.58 per share under this share repurchase program.

March 2011 CO2 Purchase Contracts

In March 2011, we entered into three long-term supply contracts to purchase CO2 from future anthropogenic sources in the Gulf Coast and Rocky Mountain regions. The three contracts are in addition to the previously disclosed long-term supply contracts Denbury currently has in place in the Gulf Coast, Rocky Mountain and Midwest regions. We will purchase 100% of the CO2 captured from the DKRW Advanced Fuels LLC's Medicine Bow Fuel and Power LLC project ("MBFP") near Medicine Bow, Wyoming, 70% of the CO2 captured from Mississippi Power Company's Kemper County Integrated Gasification Combined Cycle ("Mississippi Power") project in Mississippi, and 100% of the CO2captured by Air Products LLC ("Air Products") at a third-party refinery in Port Arthur, Texas. These three contracts each have an initial term of 15 to 16 years and include options to extend the term. We estimate these three sources will supply approximately 365 MMcf/d of CO2 for our enhanced oil recovery operations, although under certain circumstances, we may be obligated to purchase up to 460 MMcf/d, a portion of which would be at a reduced price per Mcf. We expect to begin taking delivery of approximately 100 MMCF/d of CO2 from the MBFP project in 2015, 115 MMcf/d of CO2 from the Mississippi Power project in 2014, and 50 MMcf/d of CO2 from Air Products in late 2012. Our aggregate maximum purchase obligation for CO2 purchased under these three contracts would be approximately $110 million per year (assuming purchases of 460 MMcf/d), plus transportation, assuming a $100 per barrel NYMEX oil price. The purchase price of CO2 will fluctuate based on the changes in the price of oil.

As is the case with all of our long-term supply contracts to purchase CO2, the three agreements entered into in March are subject to various contingencies. The Mississippi Power and Air Products plants are currently being constructed, and the MBFP project is contingent upon securing debt financing, equity commitments and receipt of all necessary consents and approvals.

February 2011 Senior Notes Refinancing

In February 2011, we issued, at par, $400 million of 6 % Senior Subordinated Notes due 2021. The net proceeds, together with cash on hand, were used to partially fund the repurchase of $525 million in principal amount of our outstanding 2013 Notes and 2015 Notes in cash tender offers to purchase $225 million principal amount of our 2013

Notes and $300 million principal amount of our 2015 Notes. In the first quarter of 2011, we accepted for purchase $169.6 million in principal of the 2013 Notes at 100.625% of par and $220.9 million in principal of the 2015 Notes at 104.125% of par. We redeemed the remaining outstanding 2015 Notes at 103.75% of par during the first quarter of 2011 and all of the remaining outstanding 2013 Notes at par on April 1, 2011. During the nine months ended September 30, 2011, we recognized $16.1 million of loss associated with the debt repurchases, included in our income statements under the caption “Loss on early extinguishment of debt”.

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DENBURY RESOURCES INC.

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

Capital Resources and Liquidity

We currently project that our 2011 oil and gas capital investments will be $1.35 billion, excluding capitalized interest, tertiary start-up costs, acquisitions and divestitures, and net of equipment leases.

Our current 2011 capital budget includes the following:

- $475 million allocated for tertiary oil field expenditures;
- $400 million in the Bakken area of North Dakota;
- $200 million to be spent on our CO2 pipelines;
- $200 million to be spent on CO2 sources in the Jackson Dome and Riley Ridge areas; and
- $75 million on drilling, completion and other development activities in our other areas.

During the first nine months of 2011, we have incurred expenditures of approximately $1 billion associated with our capital budget, net of equipment lease recoveries of $43 million. Additionally, we have capitalized interest of $42.0 million and tertiary start-up costs related to Hastings and Oyster Bayou Fields of $23 million, which are not included in the above mentioned capital budget. See additional detail on our expenditures below.

Based on oil and natural gas commodity futures prices in early November 2011 and our current production forecasts, excluding acquisition costs, our 2011 capital budget, including capitalized interest and tertiary start-up costs, is expected to be $150 million to $250 million greater than our 2011 anticipated cash flow from operations. This shortfall is expected to be funded with cash on hand (which was $381.9 million at December 31, 2010), and borrowings under our $1.6 billion bank credit facility. Additionally, the future sale of our investment in Vanguard Natural Resources LLP units acquired in the sale of ENP, which have ranged in value between approximately $80 million and $95 million during the third quarter of 2011, could serve as another source of proceeds to fund our capital spending. At October 31, 2011, we had drawn $350 million under our Bank Credit Facility, which was used in part to fund our August 1, 2011 Riley Ridge acquisition discussed above and in part to fund our share repurchase program discussed above.

As discussed above, in October 2011 we announced a common share repurchase program for up to $500 million of Denbury shares. We plan to fund our share repurchase program in the near term through borrowings on our Bank Credit Facility and in the longer term by reducing our 2012 capital investments and/or by using proceeds from planned asset sales of miscellaneous minor properties. As it is difficult to forecast future commodity prices, the number of shares repurchased and proceeds from asset sales, we may need to adjust our 2012 plans throughout the year as our goal is to keep any incremental debt related to these combined activities to approximately $250 million or less. See details regarding our share repurchases above.

We continually monitor our capital spending and anticipated cash flows and believe that we can adjust our capital spending up or down depending on cash flows; however, any such reduction in capital spending could impact the timing of our future production. There are potential limitations on the amount of capital spending we can eliminate without penalties (refer to Management's Discussion and Analysis – Capital Resources and Liquidity - Off-Balance Sheet Arrangements — Commitments and Obligations in our Annual Report on Form 10-K for the year ended December 31, 2010, and see CO2 Purchase Contracts above and Off-Balance Sheet Arrangements below for further information regarding additional commitments entered into during 2011). In addition to the potential flexibility in our capital spending plans, as of October 31, 2011, we had approximately $1.25 billion of unused liquidity under our bank credit facility and have oil price floors through the first quarter of 2013 (see Note 4 to the Unaudited Condensed

Consolidated Financial Statements), which together should provide us with adequate liquidity and flexibility to meet our near-term capital spending plans if oil prices were to decrease significantly.

Our capital spending estimate also assumes that we fund approximately $60 million of budgeted equipment purchases with operating leases, the amount of which is dependent upon securing acceptable financing. Through September 30, 2011, we have funded approximately $43 million of these budgeted equipment purchases with operating leases. Our net capital expenditures would increase by the amount of any shortfall in operating leases for this purchased equipment, and we anticipate funding any such additional capital expenditures under our Bank Credit Agreement.

In September 2011, we entered into our Sixth Amendment to the Bank Credit Agreement, enabling us to make certain distributions to our equity holders, including repurchase our common stock and/or make cash dividends on such common stock, in an aggregate amount of up to $500 million. Also in September 2011, the banks reaffirmed our borrowing base of $1.6 billion under the Bank Credit Agreement. See further discussion in Note 3 to the Unaudited Condensed Consolidated Financial Statements.

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Capital Expenditure Summary

The following table of capital expenditures includes accrued capital for the nine months ended September 30, 2011 and 2010:

	Nine Months Ended September 30,	
In thousands	2011	2010
Oil and natural gas exploration and development:		
Drilling	$399,812	$242,302
Geological, geophysical, and acreage	26,609	23,381
Facilities	195,928	99,797
Recompletions	177,569	136,357
Capitalized interest	31,116	23,672
Total oil and natural gas exploration and development expenditures	831,034	525,509
CO2 and other non-hydrocarbon gases capital expenditures:		
Drilling	47,750	29,222
Geological, geophysical, and acreage	9,314	17,341
Facilities	24,926	20,291
Total CO2 and other non-hydrocarbon gases capital expenditures	81,990	66,854
Pipelines and plants capital expenditures:		
Pipelines and plants	114,024	138,511
Capitalized interest	10,888	32,407
Total pipelines and plants capital expenditures	124,912	170,918
Total capital expenditures excluding acquisitions	1,037,936	763,281
Oil and natural gas property acquisitions	34,291	24,390
Consideration for the Encore Merger(1)	-	2,952,515
Consideration for August 2011 Riley Ridge acquisition	214,554	-
Total	$1,286,781	$3,740,186

(1) Consideration given in the Encore Merger includes $2.09 billion for the fair value of Denbury common stock issued.

Our capital expenditures, excluding the Riley Ridge acquisition, for the first nine months of 2011 were funded with $839.1 million of cash flow from operations, and cash on hand at the beginning of the period. Our capital expenditures for the first nine months of 2010, excluding the Encore Merger, were funded with $592.8 million of cash flow from operations together with proceeds from the sales of our interests in Genesis Energy, L.P. ("Genesis") and non-strategic legacy Encore properties sold during May 2010 (the "Southern Assets").

Off-Balance Sheet Arrangements

Our obligations that are not currently recorded on our balance sheet consist of our operating leases and various obligations for development and exploratory expenditures arising from purchase agreements, our capital expenditure program, or other transactions common to our industry. In addition, in order to recover our proved undeveloped reserves, we must also fund the associated future development costs as forecasted in our proved reserve reports. Our derivative contracts, which are recorded at fair value in our balance sheets, are discussed in Notes 4 and 5 to the

Unaudited Condensed Consolidated Financial Statements.

In April 2011, we entered into three long-term drilling contracts. Our total commitment under these contracts is approximately $91 million, with $7 million expected to be paid during the remainder of 2011, $31 million in both 2012 and 2013, and $22 million in 2014.

In May 2011, we entered into an agreement with Elk Petroleum to acquire a 65% working interest in Grieve Field, a planned CO_2 enhanced oil recovery project located in Wyoming. Denbury will invest the first $28.5 million of capital and operating costs in Phase 1. In Phase 2 of the project, Denbury may fund, at Elk's option, Elk's 35% share of the next $34.3 million of capital and operating costs, with Denbury recouping its Phase 2 expenditures (plus interest) out of Elk's 35% working interest share of production from the project. In connection with that agreement, we were assigned a CO_2 purchase and CO_2 transportation contract to purchase CO_2 reserves from Exxon Mobil Corporation's La Barge facility and transport the CO_2 to Grieve Field beginning in March of 2012. Our annual commitment under the CO_2 purchase and transportation contracts is approximately $16 million annually for 2 years and approximately $25 million annually for the remaining 8 years (assuming a $100 per barrel NYMEX oil price).

Our commitments and obligations consist of those detailed as of December 31, 2010 in our 2010 Form 10-K under Management's Discussion and Analysis of Financial Condition and Results of Operations - Off-Balance Sheet Arrangements – Commitments and Obligations, plus the long-term drilling contracts described above, the Grieve Field obligations detailed above, and the three CO_2 purchase contracts entered into during the first quarter of 2011, which CO_2 purchase contracts are subject to numerous contingencies, as discussed under Overview – CO_2 Purchase Contracts above.

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Results of Operations

CO2 Operations

Our focus on CO2 operations is the primary strategy 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 on Form 10-K for the year ended December 31, 2010 and other public disclosures. In addition to its long-term effect, our focus on these types of operations impacts certain trends in our current and near-term operating results. Please refer to Management's Discussion and Analysis of Financial Condition and Results of Operations and the section entitled CO2 Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2010 for further information regarding these matters.

During the third quarter of 2011, our CO2 production at Jackson Dome averaged 1,001 MMcf/d, compared to an average of 864 MMcf/d produced during the third quarter of 2010 and 992 MMcf/d produced during the second quarter of 2011. We used 90% of this production, or 903 MMcf/d, in our tertiary operations during the third quarter of 2011, and sold the balance to our industrial customers or to Genesis pursuant to our volumetric production payments. Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Off-Balance Sheet Arrangements – Commitments and Obligations in our Annual Report on Form 10-K for the year ended December 31, 2010 for further discussion on our CO2 delivery obligations. We recognized a negative proven CO2 reserve revision during the second quarter of approximately 239 Bcf at our Jackson Dome Dri-Dock prospect. This revision was a result of the second well in this formation not being a productive well and analysis of the reprocessed seismic data, which showed incremental faulting in the Dri-Dock reservoir. During October, 2011, we completed another well in the Gluckstadt prospect. We estimate that this well added approximately 313 Bcf of additional proven CO2 reserves. After adjusting for these changes, we believe that we have sufficient CO2 reserves to develop our current Gulf Coast enhanced oil recovery program and we are continuing to drill additional wells to increase our productive capability and to test the significant probable and possible reserves at Jackson Dome. At December 31, 2010, our proven CO2 reserves at Jackson Dome were approximately 7.1 Tcf.

During the fourth quarter of 2011 we commenced drilling an exploratory well at Jackson Dome. Because we have not established proved or probable reserves in the drilling area, in accordance with our accounting policy for CO2 properties, we expect to expense between $9 million and $12 million of drilling costs during the fourth quarter of 2011, which will be classified as "CO2 discovery and operating expenses" on our Statement of Operations.

We spent approximately $0.26 per Mcf in operating expenses to produce our CO2 during the first nine months of 2011, which costs averaged $0.25 per Mcf during the first quarter of 2011, $0.28 per Mcf during the second quarter of 2011, and $0.24 per Mcf during the third quarter of 2011. This rate is up significantly from our $0.21 per Mcf cost during the third quarter of 2010, due primarily to increased CO2 royalty expense as a result of higher oil prices (to which CO2 royalties are tied).

The following table summarizes our tertiary oil production and tertiary lease operating expense per Bbl for each quarter in 2010 and the first, second, and third quarters of 2011:

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	Average Daily Production (Bbls/d)						
Tertiary Oil Field	First Quarter 2010	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	First Quarter 2011	Second Quarter 2011	Third Quarter 2011
Phase 1:							
Brookhaven	3,416	3,277	3,323	3,699	3,664	3,213	3,030
McComb area	2,289	2,160	2,484	2,433	2,161	1,983	2,005
Mallalieu area	3,443	3,628	3,279	3,164	2,925	2,646	2,620
Other	2,817	3,282	3,343	3,361	3,290	3,196	2,879
Phase 2:							
Heidelberg	1,708	1,857	2,806	3,422	3,374	3,548	3,141
Eucutta	3,792	3,625	3,284	3,286	3,247	3,114	2,985
Soso	3,213	3,207	3,016	2,828	2,582	2,317	2,331
Martinville	927	764	606	586	500	416	453
Phase 3:							
Tinsley	4,419	5,248	6,024	6,614	6,567	6,990	7,075
Phase 4:							
Cranfield	936	811	855	1,043	991	1,085	1,214
Phase 5:							
Delhi	63	648	511	703	1,524	2,263	3,358
Total tertiary oil production	27,023	28,507	29,531	31,139	30,825	30,771	31,091
Tertiary operating expense per Bbl	$22.67	$21.37	$22.54	$22.26	$25.40	$23.35	$25.34

Oil production from our tertiary operations increased to an average of 31,091 Bbls/d during the third quarter of 2011, a 5% increase over our third quarter of 2010 tertiary production level, primarily due to production growth in response to continued expansion of the tertiary floods in the Delhi, Tinsley, Cranfield, and Heidelberg Fields. The initial tertiary production response at Delhi Field occurred late in the first quarter of 2010, and production there has subsequently increased steadily as we have expanded the CO2 flood. Offsetting these production gains were declines in our more mature Phase 1 and Phase 2 fields (excluding Heidelberg).

The production growth rate at a tertiary flood can vary from quarter to quarter as a tertiary field's production may increase rapidly when wells respond to the CO2, plateau temporarily, and then resume its growth as additional areas of the field are developed. During a tertiary flood life cycle, facility capacity is increased from time to time, which occasionally requires temporary shutdowns during installation, thereby causing temporary declines in production. We also find it difficult to precisely predict when any given well will respond to the injected CO2, as the CO2 seldom travels through the rock consistently due to heterogeneity in the oil-bearing formations. We find all of these fluctuations to be normal, and generally expect oil production at a tertiary field to increase over time until the entire field is developed, albeit sometimes in inconsistent patterns. These types of fluctuations were most noticeable at Tinsley and Heidelberg Fields during the first three quarters of 2011, two of our fields which have exhibited strong production growth in the recent past. During the third quarter of 2011, we shut-in our Heidelberg Field for seven days for compressor maintenance and repairs to the main facility, which we estimate lowered third quarter tertiary production from the field by approximately 250 Bbls/d. In addition, at Heidelberg Field we experienced rapid production growth in late 2010 as the CO2 moved rapidly through the more permeable zones. We are implementing a plan which will force the CO2 into the less permeable zones in order to recover the oil trapped in those intervals. At Tinsley Field, we stopped CO2 injections in parts of the field in order to address issues with wells that were improperly plugged by prior operators. These issues have slowed our previously anticipated production growth this year, and production growth will likely not resume until 2012. These temporary fluctuations have not changed our overall expectations of recovery in the Heidelberg and Tinsley Fields.

We initiated CO2 injections at Oyster Bayou and Hastings Fields during June 2010 and December 2010, respectively. We currently anticipate initial tertiary production at Hastings around year-end 2011 and first tertiary production at Oyster Bayou Field late in the first quarter of 2012, assuming completion of CO2 recycle facilities.

We commenced construction of the first segment of our 232-mile, 20-inch Greencore CO2 pipeline in Wyoming during August 2011. This 114-mile segment of the pipeline starts in Natrona County and runs through Johnson and southwestern Campbell Counties, Wyoming. In late 2012 we plan to complete the compression station at Lost Cabin and complete the pipeline to Bell Creek Field in southeast Montana.

During the third quarter of 2011, operating costs for our tertiary properties averaged $25.34 per Bbl, up 12% from our third quarter 2010 average cost of $22.54 per Bbl, due primarily to higher workover, repair and equipment rental expenses in the most recent quarter, plus higher CO2 costs due to higher oil prices. For the first nine months of 2011, operating costs for our tertiary properties averaged $24.70 per Bbl, an increase of 11% compared to such costs in the prior-year period, with such increase attributable to similar factors except that equipment rental was essentially flat and the increase in CO2 costs was more significant. The increase in workover expenses for these periods is primarily due to maintenance and repairs at Heidelberg Field and workover costs at Tinsley Field as discussed above. The increase in equipment rental expense in the third quarter comparison is due primarily to additional leasing on certain facility equipment in 2011. For any specific field, we expect our tertiary lease operating expense per Bbl to be high initially and then decrease as production increases, ultimately leveling off until production begins to decline in the latter life of the field, when lease operating expense per barrel will again increase.

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DENBURY RESOURCES INC.

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Operating Results

Certain of our operating results and statistics for the comparative third quarters and first nine months of 2011 and 2010 are included in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share and unit data	2011	2010(1)	2011	2010(1)
Operating results:				
Net income attributable to Denbury stockholders	$275,670	$29,104	$520,726	$261,359
Net income per common share - basic	0.69	0.07	1.31	0.72
Net income per common share - diluted	0.68	0.07	1.29	0.71
Cash flow from operations	315,739	208,484	839,092	592,775
Average daily production volumes:				
Bbls/d	61,984	64,233	60,007	58,234
Mcf/d	29,079	80,983	30,736	81,065
BOE/d	66,830	77,730	65,129	71,745
Operating revenues:				
Oil sales	$552,281	$426,896	$1,621,047	$1,176,085
Natural gas sales	13,242	33,889	41,767	103,614
Total oil and natural gas sales	$565,523	$460,785	$1,662,814	$1,279,699
Commodity derivative contracts: (2)				
Net cash receipts (payments) on settlement of commodity derivative contracts	$4,570	$10,036	$(4,784)	$(46,964)
Non-cash fair value derivative gains (losses)	205,584	(42,517)	217,092	183,512
Total income (expense) from commodity derivative contracts	$210,154	$(32,481)	$212,308	$136,548
Operating expenses:				
Lease operating	$136,531	$131,768	$393,560	$355,731
Production taxes and marketing	36,949	35,542	109,388	92,959
Total production expenses	$173,480	$167,310	$502,948	$448,690
Unit prices - including impact of derivative settlements: (2)				
Oil price per Bbl	$96.52	$71.63	$97.50	$68.88
Natural gas price per Mcf	7.35	6.38	7.25	6.22
Unit prices - excluding impact of derivative settlements: (2)				
Oil price per Bbl	$96.85	$72.24	$98.95	$73.98
Natural gas price per Mcf	4.95	4.55	4.98	4.68
Oil and natural gas operating revenues and expenses per BOE:				
Oil and natural gas revenues	$91.98	$64.44	$93.52	$65.34
Oil and natural gas lease operating expenses	$22.21	$18.43	$22.13	$18.16
Oil and natural gas production taxes and marketing expense	6.01	4.97	6.15	4.75
Total oil and natural gas production expenses	$28.22	$23.40	$28.28	$22.91

(1) Includes the results of operations of Encore properties and ENP from March 9, 2010 through September 30, 2010.
(2) See Item 3, Qualitative and Quantitative Disclosures about Market Risk, for additional information concerning our commodity derivative contracts.

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Production

Average daily production by area for each of the four quarters of 2010 and for the first, second, and third quarters of 2011 are shown below:

	Average Daily Production (BOE/d)							
Operating Area	First Quarter 2010(1)	Pro Forma First Quarter 2010(2)	Second Quarter 2010	Third Quarter 2010	Fourth Quarter 2010	First Quarter 2011	Second Quarter 2011	Third Quarter 2011
Gulf Coast Region:								
Tertiary oil fields	27,023	27,023	28,507	29,531	31,139	30,825	30,771	31,091
Non-tertiary fields:								
Mississippi	7,829	7,829	8,967	7,965	7,293	7,586	7,333	7,193
Texas	5,235	5,235	5,148	4,824	4,564	4,371	4,202	4,096
Louisiana	662	662	775	714	687	767	659	214
Alabama and other	997	997	1,078	1,091	1,026	1,026	1,084	1,072
Total Gulf Coast Region	41,746	41,746	44,475	44,125	44,709	44,575	44,049	43,666
Rocky Mountain Region:								
Cedar Creek Anticline	2,537	9,830	9,967	9,791	9,328	9,163	8,925	8,930
Bakken	890	3,549	4,500	4,657	5,193	5,728	7,626	9,976
Bell Creek	252	966	997	994	957	890	936	889
Paradox	173	675	702	738	716	635	690	680
Other	777	2,925	2,944	2,889	2,809	2,613	2,693	2,689
Total Rocky Mountain Region	4,629	17,945	19,110	19,069	19,003	19,029	20,870	23,164
Total Continuing Production	46,375	59,691	63,585	63,194	63,712	63,604	64,919	66,830
Disposed Properties:								
	4,479	17,853	11,684	5,906	4,156	-	-	-

Legacy Encore properties								
ENP	2,271	9,034	8,842	8,630	8,567	-	-	-
Total Production	53,125	86,578	84,111	77,730	76,435	63,604	64,919	66,830

(1) Includes production of Encore and ENP from March 9, 2010 through March 31, 2010.
(2) Represents pro forma production assuming we had reported the production from the Encore Merger beginning January 1, 2010.

Continuing production during the three months ended September 30, 2011 increased 3,636 BOE/d over the comparable 2010 production levels, and continuing production when including Encore's pre-merger production increased from 62,169 BOE/d during the first nine months of 2010 to 65,129 BOE/d during the first nine months of 2011. These increases were primarily due to production increases from the Bakken and our tertiary oil fields (see a discussion of our tertiary operations in CO2 Operations above), offset by normal declines in most of our other non-tertiary properties. Total production decreased 14% between the third quarters of 2010 and 2011 due to the sale of the Haynesville natural gas assets, as well as the sale of our interests in ENP, in the fourth quarter of 2010. On a year-to-date basis, total production decreased 6,616 BOE/d between the first nine months of 2010 and 2011 due primarily to the sale of the non-strategic Encore assets, including the Haynesville and ENP interests, during 2010. Our production from the Cedar Creek Anticline generally declines in periods of increasing prices due to a net profits interest associated with this production; therefore, a portion of the decline in 2011 production at this field is related to the increase in oil prices during 2011.

Production from our Bakken properties averaged 9,976 BOE/d in the third quarter of 2011, a 114% increase from third quarter 2010 levels and an increase of over 31% compared to second quarter 2011 production levels. The production increases in the Bakken are due to an acceleration of our drilling activities in the area, as we have increased our operated drilling rigs from two at the time of the Encore acquisition in March 2010, to five rigs at the beginning of 2011, and seven operated rigs at the end of the third quarter of 2011. During the first nine months of 2011, we drilled and completed 24 operated wells in the Bakken. Our Bakken production growth for the first six months of 2011 was negatively impacted by severe winter weather and spring flooding, which caused delays in well completions and curtailments in oil production; however, with the increase in operated drilling rigs and good weather conditions we have caught up on the backlog of our wells requiring fracturing treatment. A test well drilled in the Almond area in October 2011 indicated the reservoir was noncommercial at the current oil price. Based on the results of the first test well, we determined a second Almond test was not necessary to evaluate the area.

Our production during the three and nine months ended September 30, 2011 was 93% and 92% oil, respectively, as compared to 83% and 81% oil during the three and nine months ended September 30, 2010, respectively. This increase is due to the sales of the non-strategic Encore properties and ENP properties in 2010, which had a higher percentage of natural gas production, and increases in our tertiary and Bakken production, which are primarily oil.

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Oil and Natural Gas Revenues. Although our production for the three and nine months ended September 30, 2011 declined from comparable 2010 levels due to the asset sales discussed above, our oil and natural gas revenues increased significantly in the current periods due to higher oil prices. These changes in oil and natural gas revenues, excluding any impact of our commodity derivative contracts, are reflected in the following table:

	Three Months Ended September 30, 2011 vs. 2010		Nine Months Ended September 30, 2011 vs. 2010	
In thousands	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues	Increase (Decrease) in Revenues	Percentage Increase (Decrease) in Revenues
Change in oil and natural gas revenues due to:				
Increase in commodity prices	$ 169,368	37%	$ 501,114	39%
Decrease in production	(64,630)	(14%)	(117,999)	(9%)
Total increase in oil and natural gas revenues	$ 104,738	23%	$ 383,115	30%

Excluding any impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during the first, second, and third quarters and the nine months ended September 30, 2011 and 2010:

	Three Months Ended March 31,		Three Months Ended June 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010	2011	2010	2011	2010
Net Realized Prices:								
Oil price per Bbl	$93.67	$76.53	$106.30	$73.99	$96.85	$72.24	$98.95	$73.98
Natural gas price per Mcf	4.81	5.40	5.16	4.44	4.95	4.55	4.98	4.68
Price per BOE	88.42	69.21	100.06	63.76	91.98	64.44	93.52	65.34
NYMEX Differentials:								
Oil per Bbl	$(0.59)	$(2.08)	$3.72	$(4.13)	$7.25	$(3.85)	$3.49	$(3.62)
Natural gas per Mcf	0.61	0.37	0.78	0.09	0.89	0.31	0.77	0.14

As reflected in the table above, our oil price differentials have continued to improve significantly, primarily due to the favorable price differential for crude oil sold under LLS index pricing. Company-wide oil price differentials in the third quarter of 2011were $7.25 per Bbl above NYMEX, as compared to an average negative differential of $3.85 per Bbl below NYMEX in the third quarter of 2010, an increase of $11.10 per Bbl. Our oil price differentials in the 2010 periods reflected production from the non-strategic Encore properties sold in 2010, which typically received lower oil prices than our legacy production. During the latter part of the first quarter of 2011, the LLS index price increased significantly more than NYMEX prices, causing the LLS differential to increase significantly, and it has remained high and further increased throughout the second and third quarters. For the third quarter of 2011, this LLS differential averaged a positive $18.90 per barrel on a trade-month basis, as compared to a $9.28 and $15.32 positive differential in the first and second quarters of 2011, respectively, and a more typical $3.11 positive differential in the third quarter of 2010. It is uncertain how long this LLS differential will remain at this level. Because our derivative contracts are based on NYMEX prices, they do not impact the differential we receive. We currently sell approximately (a) 42% of our crude oil based on the LLS index price, although due to contract provisions we may not realize the full differential; (b) 38% based on WTI prices; and (c) 20% based on various other indexes, most of which have also improved relative to WTI, but to a lesser degree.

Commodity Derivative Contracts. The following tables summarize the impact our commodity derivative contracts had on our operating results for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,					
	2011	2010	2011	2010	2011	2010
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$205,355	$(62,450)	$229	$19,933	$205,584	$(42,517)
Cash settlement receipts (payments)	(1,857)	(3,590)	6,427	13,626	4,570	10,036
Total	$203,498	$(66,040)	$6,656	$33,559	$210,154	$(32,481)

	Nine Months Ended September 30,					
	2011	2010	2011	2010	2011	2010
In thousands	Oil Derivative Contracts		Natural Gas Derivative Contracts		Total Commodity Derivative Contracts	
Non-cash fair value gain (loss)	$225,485	144,471	(8,393)	39,041	$217,092	$183,512
Cash settlement receipts (payments)	(23,857)	(80,969)	19,073	34,005	(4,784)	(46,964)
Total	$201,628	$63,502	$10,680	$73,046	$212,308	$136,548

Changes in commodity prices and the expiration of contracts cause fluctuations in the estimated fair value of our commodity derivative contracts. Because we do not utilize hedge accounting for our commodity derivative contracts, the changes in fair value of these contracts, as outlined above, are recognized currently in the income statement. See Notes 4 and 5 to the Unaudited Condensed Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

Production Expenses. Our lease operating expenses increased 4% during the three months ended September 30, 2011 compared to the level of these expenses in the same period in 2010. This increase is primarily attributable to an 18% increase in our tertiary operating expenses, from $61.3 million to $72.5 million, offset in part by a decrease in our non-tertiary lease operating expenses of $6.5 million, or 9%. The increase in our tertiary operating expenses is due primarily to additional CO_2 injection costs due to higher oil prices (to which CO_2 prices are partially tied) and increased workover costs, which increases are further discussed above under CO_2 Operations. The decrease in our non-tertiary operating costs is primarily due to the sale of Haynesville properties and ENP in the fourth quarter of 2010, which reduced our lease operating costs by $12.3 million, offset in part by increases in operating expenses in our Rocky Mountain region, primarily at Cedar Creek Anticline, where we experienced higher workover costs in the third quarter of 2011.

For the nine months ended September 30, 2011, our lease operating expenses increased by 11% over those in the 2010 nine month period. This increase is also primarily attributable to a 21% increase in our tertiary operating expenses, from $171.8 million to $208.3 million. Our non-tertiary lease operating expenses increased slightly over the prior year nine-month period (1%), as the savings of approximately $35.8 million due to the sale of legacy Encore assets in 2010 was offset by increased expenses in the Cedar Creek Anticline Field and other Rocky Mountain region properties, including our expansion of Bakken Field operations.

Lease operating expense averaged $22.21 per BOE and $22.13 per BOE for the three and nine months ended September 30, 2011, compared to $18.43 per BOE and $18.16 per BOE for the same periods in 2010. These increases from the respective prior periods are attributable to the sale of the non-strategic Encore and ENP properties from May 2010 through December 2010, which were primarily natural gas properties that generally had a lower operating cost per BOE than Denbury’s legacy properties. Our tertiary operating costs, which have historically been higher than our company-wide operating costs, averaged $25.34 per Bbl and $24.70 per Bbl during the three and nine months ended September 30, 2011, compared to $22.54 per Bbl and $22.19 per Bbl for the same periods in 2010. See CO_2 Operations for a more detailed discussion.

Generally, production taxes change in relation to oil and natural gas revenues, and marketing expenses change in relation to production volumes. The 23% increase in oil and natural gas revenues between the third quarters of 2010 and 2011 contributed to severance taxes increasing from $26.2 million in 2010 to $30.5 million in 2011. Likewise, the 30% increase in oil and natural gas revenues between the first nine months of 2010 and 2011 contributed to severance taxes increasing from $69.8 million in the first nine months of 2010 to $91.4 million in the first nine months of 2011. These severance tax increases in both comparative periods were partially offset by lower marketing expenses primarily attributable to lower production volumes in 2011.

General and Administrative Expenses (“G&A”)

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE data and employees	2011	2010	2011	2010
Gross G&A expenses (excluding stock compensation)	$57,061	$61,532	$184,895	$167,715
Gross stock-based compensation	11,154	9,832	32,178	27,134
State franchise taxes	1,894	952	4,721	2,987
Operator labor and overhead recovery charges	(31,720)	(30,633)	(92,859)	(81,764)
Capitalized exploration and development costs	(9,483)	(4,568)	(25,283)	(15,056)

Net G&A expense	$28,906	$37,115	$103,652	$101,016
G&A per BOE:				
Net G&A expense(1)	$2.94	$3.88	$4.14	$3.83
Net stock-based compensation(1)	1.45	1.18	1.42	1.18
State franchise taxes	0.31	0.13	0.27	0.15
Net G&A expense	$4.70	$5.19	$5.83	$5.16
Employees as of September 30	1,274	1,225	1,274	1,225

(1) Net of operator labor and overhead recovery charges, and capitalized exploration and development costs.

Gross G&A expenses decreased $4.5 million (7%) during the three months ended September 30, 2011, but increased $17.2 million (10%) during the nine months ended September 30, 2011, as compared to the same periods of 2010. The decrease between the comparative third quarters was primarily caused by a reduction in third-party professional services and accrued bonus compensation, offset in part by higher salary and benefits costs and additional compensation related to the resignation of Tracy Evans from his officer's position as Denbury's President and Chief Operating Officer. Gross stock-based compensation was also higher in the 2011 periods, due in part to the President and Chief Operating Officer's resignation of his officer's position.

The year-to-date comparative increase is primarily impacted by increased expense resulting from the Encore Merger, as the 2010 period includes the effect of the Encore Merger beginning on the acquisition date, March 9, 2010. The number of employees at September 30, 2011 represents a 49% increase over our headcount prior to the Encore Merger, which was 856 employees. Additional expense attributable to the legacy Encore office leases and the new Denbury headquarters lease, together with related moving costs, also contributed to the higher cash G&A expense during the first nine months of 2011.

Gross G&A expense during the three and nine months ended September 30, 2011 was offset in part by an increase in operator overhead recovery charges. Our well operating agreements allow us, when we are the operator, to charge a well with a specified overhead rate during the drilling phase and also to charge a monthly fixed overhead rate for each producing well. As a result of additional operated wells and drilling activities, additional tertiary operations and increased compensation expense, the amount we recovered as operator labor and overhead charges increased by 4% and 14% during the three and nine months ended September 30, 2011, as compared to the same periods in 2010. Capitalized exploration and development costs also increased between the periods, primarily due to increased compensation costs subject to capitalization.

The net effect of these changes resulted in a 22% decrease (a 9% decrease on a per BOE basis) in G&A expense between the comparable third quarters of 2011 and 2010, and a 3% increase (13% increase on a per BOE basis) between the comparable first nine months of 2011 and 2010. Lower production attributable to the 2010 property sales was the primary factor relating to the higher cost per BOE in the 2011 nine-month period as compared to the 2010 nine-month period, as any cost savings as a result of the property sales were offset by other expenses, including compensation increases effective at the beginning of 2011 and incremental expense attributable to the legacy Encore office leases and the new Denbury headquarters noted above.

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Interest and Financing Expenses

In thousands, except per BOE data and interest rates	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cash interest	$ 51,540	$ 58,234	$ 156,255	$ 164,173
Non-cash interest	3,930	6,014	14,392	15,136
Less: capitalized interest	(17,853)	(10,917)	(42,004)	(56,079)
Interest expense, net	$ 37,617	$ 53,331	$ 128,643	$ 123,230
Interest income and other	$ 4,441	$ 1,268	$ 12,445	$ 7,658
Net cash interest expense and other income per BOE (1)	$ 4.80	$ 6.57	$ 5.79	$ 5.27
Average debt outstanding	$ 2,426,820	$ 2,751,258	$ 2,415,193	$ 2,710,573
Average interest rate (2)	8.5 %	8.5 %	8.6 %	8.1 %

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

Cash interest expense decreased $6.7 million during the three month period ending September 30, 2011, as compared to the same period in 2010, primarily due to a decrease in our average debt outstanding. Our debt level increased in early 2010 as a result of the Encore Merger and decreased throughout 2010 and in early 2011 as we repaid debt with proceeds from the sale of non-strategic legacy Encore assets and our ENP ownership interests. As a result, our year-to-date cash interest expense was also lower than that incurred in the same period in 2010. The 64% increase in capitalized interest between the third quarters of 2010 and 2011 relates primarily to incremental capitalized interest on CO2 floods, Riley Ridge and the Greencore Pipeline, offset in part by a reduction in capitalized interest on the Green Pipeline, a significant portion of which was placed into service in June 2010, with the remaining portion placed into service in December 2010. Capitalized interest for the 2011 nine-month period is lower than in the 2010 nine-month period due to capitalized interest in the prior year period related to the Green Pipeline.

Depletion, Depreciation, and Amortization ("DD&A")

In thousands, except per BOE data	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
DD&A of oil and natural gas properties	$90,241	$108,692	$264,288	$295,923
Depletion and depreciation of CO2 assets	4,625	4,984	13,803	15,964
Asset retirement obligations	1,456	1,877	4,715	4,676
Depreciation of other fixed assets	5,656	5,668	16,261	15,739
Cumulative change due to revision in policy for CO2 properties	-	(9,619)	-	(9,619)
Total DD&A	$101,978	$111,602	$299,067	$322,683
DD&A per BOE:				
Oil and natural gas properties	$14.91	$15.46	$15.13	$15.35
CO2 assets and other fixed assets	1.68	1.49	1.69	1.62
	-	(1.34)	-	(0.49)

Cumulative change due to revision in policy for CO2 properties				
Total DD&A cost per BOE	$16.59	$15.61	$16.82	$16.48

Depletion of oil and natural gas properties decreased on an absolute dollars basis during the three and nine months ended September 30, 2011 as compared to the same periods of 2010, primarily due to the sale of non-strategic legacy Encore assets and our ownership interests in ENP during 2010. DD&A of oil and natural gas properties decreased from $15.85 per BOE in the second quarter of 2011 to $14.91 per BOE during the third quarter of 2011 due primarily to the impact of natural gas reserves added from the Riley Ridge acquisition in the third quarter of 2011. DD&A per BOE also decreased from the third quarter of 2010 as compared to the third quarter 2011, as reserve additions during the period more than replaced the decline in reserves resulting from the sale of the legacy Encore and ENP properties.

We continually evaluate the performance of our tertiary projects, and if performance indicates that we are reasonably certain of recovering additional reserves from these floods, we recognize those incremental reserves in that quarter. Since we adjust our DD&A rate each quarter based on any changes in our estimates of oil and natural gas reserves and costs, our DD&A rate could change significantly in the future.

Our DD&A expense for our CO2 assets decreased on an absolute basis for the three and nine months ended September 30, 2011 compared to the same periods in 2010 due to proved CO2 reserve increases at Jackson Dome and Riley Ridge at the end of 2010. On a per BOE basis, DD&A expense for our CO2 assets and other fixed assets increased for the three and nine months ended September 30, 2011 compared to those in the prior-year quarter due to decreased oil and natural gas production volumes as a result of the sale of non-strategic Encore properties and our interests in ENP during 2010.

Under full cost accounting rules, we are required each quarter to perform a ceiling test calculation. We did not have a ceiling test write-down at September 30, 2011. However, if oil and natural gas prices were to decrease significantly in subsequent periods, we may be required to record write-downs under the full cost pool ceiling test in the future. The possibility and amount of any future write-down is difficult to predict, and will depend upon oil and natural gas prices, the incremental proved reserves that may be added each period, revisions to previous reserve estimates and future capital expenditures, and additional capital spent.

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Encore Transaction and Other Costs

FASC Business Combinations topic requires that all transaction-related costs (advisory, legal, accounting, due diligence, integration, etc.) be expensed as incurred. We recognized transaction and other costs of $4.4 million during the nine months ended September 30, 2011 associated with the Encore Merger, including $3.6 million related to severance costs. Transaction and other costs of $11.5 million and $79.3 million for the three and nine months ended September 30, 2010, respectively, included $10.7 million and $31.4 million, respectively, of severance costs, and were significantly higher than 2011 levels.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per BOE amounts and tax rates	2011	2010	2011	2010
Current income tax provision (benefit)	$(5,331)	$3,704	$5,849	$11,314
Deferred income tax provision	172,981	16,595	317,601	167,289
Total income tax provision	$167,650	$20,299	$323,450	$178,603
Average income tax provision per BOE	$27.27	$2.84	$18.19	$9.12
Effective tax rate	37.8 %	39.4 %	38.3 %	38.8 %

Our income taxes are based on an estimated statutory rate of approximately 38%. Our effective tax rate for the third quarter of 2011 was slightly lower compared to our statutory rate, primarily due to the recognition of additional tax benefits in our 2010 tax returns in excess of the estimated benefits included in our tax provision at December 31, 2010, offset in part by nondeductible expenses. Excluding this benefit, our effective tax rate would have been closer to 38.3% for the third quarter of 2011. Our effective tax rate for the third quarter of 2010 was higher than our statutory rate due to the recognition of incremental tax expense resulting from the reconciliation of our tax provision to the actual amounts reported on our 2009 tax returns. The higher effective rate of 38.8% during the nine months ended September 30, 2010 as compared to 38.3% in the nine months ended September 30, 2011, was primarily due to the combined effects of having to remeasure our deferred tax liabilities in conjunction with the Encore Merger in the first quarter of 2010 and the sale the certain of Encore's Southern Assets in the second quarter of 2010, which resulted in net incremental income tax expense. The amount recorded as current income tax expense represents our state income taxes during the three and nine months ended September 30, 2011 and 2010, and for the 2011 periods, federal alternative minimum taxes that we cannot offset with enhanced oil recovery credits. Our third quarter 2011 current income taxes were a net benefit due to the change in treatment for certain items between our 2010 tax provision and our 2010 filed tax return. This change in treatment resulted in a reclassification of approximately $15 million from current to deferred taxes, which represents refunds that we anticipate related to our 2010 tax period.

As of September 30, 2011, we had an estimated $51.4 million of enhanced oil recovery credits to carry forward related to our tertiary operations, and $34.8 million of alternative minimum tax credits that can be utilized to reduce our current income taxes during 2011 or future years. The enhanced oil recovery credits do not begin to expire until 2023. Since the ability to earn additional enhanced oil recovery credits is based upon the level of oil prices, we would not currently expect to earn additional enhanced oil recovery credits unless oil prices were to significantly deteriorate.

In the third quarter of 2008, we obtained approval from the National Office of the Internal Revenue Service ("IRS") to change our method of tax accounting for certain assets used in our tertiary oilfield recovery operations. As a result of the approved change in method of tax accounting, beginning with the 2007 tax year we began to deduct, rather than capitalize, such costs for tax purposes, and applied for tax refunds associated with such change for our 2004 and 2006 tax years. Notwithstanding its consent to our change in tax accounting in 2008, the IRS subsequently exercised its prerogative to challenge the tax accounting method we used. In late January 2011, we received a Technical Advice Memorandum ("TAM") issued by the IRS National Office disapproving our method of accounting and revoking its consent to our change, on a prospective basis only, commencing January 1, 2011. Henceforth, beginning with the 2011 tax year, we are returning to capitalizing and depreciating the costs of these assets for tax purposes. As a result of the prospective nature of the IRS's determination, there should be no change in our position with respect to the deductibility of these costs for 2007, 2008, 2009 and 2010. However, refund claims of $10.6 million for tax years through 2006 are pending and are pending review by the Joint Committee on Taxation of the U.S. Congress. We are unable to assess the outcome of any such review, nor how that outcome may affect the other years covered by the TAM.

The President's 2012 budget, as well as certain Congressional legislative initiatives, have proposed repealing many tax incentives for the oil and gas industry. Those items that would have the most significant impact on us would include the loss of the domestic manufacturing deduction, the repeal of the immediate expensing of intangible drilling costs and tertiary injection costs, and the elimination of the percentage depletion allowance; however, we do not believe it would impact any credits that we have earned to date. It is uncertain whether these or similar tax law changes will be enacted, and if so what the effective date of any such changes might be, although the current proposals would not take effect until 2012 or later. If some or all of these proposals were enacted and included us, they would likely increase the amount of cash taxes that we pay in future periods, and, accordingly, could impact our forecasted capital expenditure budget.

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

Per BOE Data

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

Per BOE data	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Oil and natural gas revenues	$91.98	$64.44	$93.52	$65.34
Gain (loss) on settlements of derivative contracts	0.74	1.40	(0.27)	(2.40)
Lease operating expenses	(22.21)	(18.43)	(22.13)	(18.16)
Production taxes and marketing expenses	(6.01)	(4.97)	(6.15)	(4.75)
Production netback	64.50	42.44	64.97	40.03
Non-tertiary CO2 operating margin	0.84	0.30	0.65	0.42
General and administrative expenses	(4.70)	(5.19)	(5.83)	(5.16)
Transactions and other costs related to the Encore Merger	-	(1.60)	(0.25)	(4.05)
Net cash interest expense and other income	(4.80)	(6.57)	(5.79)	(5.27)
Current income taxes and other	2.34	1.37	0.96	0.92
Changes in assets and liabilities relating to operations	(6.83)	(1.60)	(7.52)	3.37
Cash flow from operations	51.35	29.15	47.19	30.26
DD&A	(16.59)	(15.61)	(16.82)	(16.48)
Deferred income taxes	(28.13)	(2.32)	(17.86)	(8.54)
Gain on sale of interests in Genesis	-	-	-	5.18
Loss on early extinguishment of debt	-	-	(0.91)	-
Non-cash fair value derivative adjustments	33.44	(5.86)	12.21	9.45
Net income attributable to noncontrolling interest	-	(0.30)	-	(1.04)
Changes in assets and liabilities and other non-cash items	4.77	(0.99)	5.48	(5.49)
Net income attributable to Denbury stockholders	$44.84	$4.07	$29.29	$13.34

Critical Accounting Policies

For additional discussion of our critical accounting policies, 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, 2010.

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, dates of pipeline construction commencement and completion, drilling activity or methods, acquisition plans and proposals and dispositions, development activities, timing of CO2 injections and initial production response in tertiary flooding projects, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO2 reserves, potential reserves from tertiary operations, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and natural gas prices, liquidity, cash flows, availability of capital, borrowing capacity, regulatory matters, mark-to-market values, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our 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 ever 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 our 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 us or on our behalf. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for our oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets, including financial market impact of any European sovereign or related debt default; changes in interest rates; general economic conditions; competition and government regulations; electronic, cyber or physical security breaches; and unexpected delays, as well as the risks and uncertainties inherent in oil and natural gas drilling and production activities or which are otherwise discussed in this quarterly report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements.

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DENBURY RESOURCES INC.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Long-term Debt and Interest Rate Sensitivity

We finance some of our acquisitions and other expenditures with fixed and variable-rate debt. Our Bank Credit Agreement and our senior subordinated notes do not have any triggers or covenants regarding our debt ratings with rating agencies. Borrowings on our Bank Credit Agreement, which bear interest at variable rates, expose us to market risk related to changes in interest rates. As of September 30, 2011, our borrowings on our Bank Credit Agreement were $110 million, with a weighted average interest rate of 1.73%. At this level of variable-rate debt, an increase or decrease of 10% in interest rates would have an immaterial effect on our interest expense.

The following table presents the principal balances of our debt, by maturity date, as of September 30, 2011:

In thousands, except percentages	2014	2015	2016	2017	2020	2021
Variable rate debt:						
Bank Credit Agreement (weighted average interest rate of 1.73% at September 30, 2011)	$110,000	$-	$-	$-	$-	$-
Fixed rate debt:						
9.5% Senior Subordinated Notes due 2016	-	-	224,920	-	-	-
9.75% Senior Subordinated Notes due 2016	-	-	426,350	-	-	-
8.25% Senior Subordinated Notes due 2020	-	-	-	-	996,273	-
6.375% Senior Subordinated Notes due 2021	-	-	-	-	-	400,000
Other Subordinated Notes	1,072	485	-	2,250	-	-

Commodity Derivative Contracts and Commodity Price Sensitivity

From time to time, we enter into oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and natural gas production. We do not hold or issue derivative financial instruments for trading purposes. These contracts have consisted of price floors, collars and fixed price swaps. The production that we hedge has varied from year to year depending on our levels of debt and financial strength and expectation of future commodity prices. We currently employ a strategy to hedge a portion of our forecasted production for a period generally ranging from approximately 12 to 18 months in advance (although we will hedge farther in advance if deemed prudent), as we believe it is important to protect our future cash flow for a short period of time in order to give us time to adjust to commodity price fluctuations, particularly since many of our expenditures have long lead times. See Note 4, Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements for additional information regarding our commodity derivative contracts.

All of the mark-to-market valuations used for our oil and natural gas derivatives are provided by external sources. We manage and control market and counterparty credit risk through established internal control procedures that are reviewed on an ongoing basis. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures, and diversification. All of our commodity derivative contracts are with parties that are lenders under our bank credit agreement. We have included an estimate of nonperformance risk in the fair value measurement of our oil and natural gas derivative contracts, which we have measured for nonperformance risk based upon credit default swaps or credit spreads.

For accounting purposes, we do not apply hedge accounting to our commodity derivative contracts. This means that any changes in the fair value of these derivative contracts will be charged to earnings on a quarterly basis instead of charging the effective portion to other comprehensive income and the ineffective portion to earnings.

At September 30, 2011, our commodity derivative contracts were recorded at their fair value, which was a net asset of approximately $173.1 million (excluding $9.9 million of deferred premiums that Denbury is obligated to pay for its derivative contracts, which payments are not subject to changes in commodity prices), which is a change of approximately $217.1 million from the $44.0 million fair value liability recorded at December 31, 2010. This change is primarily related to changes in oil futures prices between December 31, 2010 and September 30, 2011.

Based on NYMEX crude oil and natural gas futures prices as of September 30, 2011, and assuming both a 10% increase and decrease thereon, we would expect to make or receive payments on our crude oil and natural gas derivative contracts as seen in the following table:

In thousands	Crude Oil Derivative Contracts Receipt / (Payment)	Natural Gas Derivative Contracts Receipt
Based on:		
NYMEX futures prices as of September 30, 2011	$189	$25,083
10% increase in prices	(2,305)	20,877
10% decrease in prices	67,018	29,288

Equity Price Sensitivity

Our investment in Vanguard common units is considered an investment in available-for-sale securities, which is recorded at fair value with any unrealized gains or losses included in accumulated other comprehensive income. This investment is thus subject to equity price sensitivity, as fair value is determined by quoted market prices. We estimate that a hypothetical 10% increase or decrease in quoted market prices for Vanguard common units would result in a $8.2 million unrealized gain or loss, respectively, as of September 30, 2011.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, the Company's Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2011, to ensure: that information required to be disclosed in the reports it files and submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we have determined that, during the third quarter of fiscal 2011, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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DENBURY RESOURCES INC.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information with respect to this item is incorporated by reference from our Annual Report on Form 10-K for the year ended December 31, 2010.

Item 1A. Risk Factors

Information with respect to the risk factors has been incorporated by reference from Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no material changes to the risk factors since the filing of such Form 10-K.

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

Issuer Purchases of Equity Securities

The following table summarizes purchases of our common stock during the third quarter of 2011, made solely in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares and the exercise of stock appreciation rights:

Month	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
July 2011	4,042	$ 19.49	-	$ -
August 2011	16,298	18.15	-	-
September 2011	3,581	14.63	-	-
Total	23,921	17.85	-	$ -

In addition, in early October 2011, we announced the commencement of a common share repurchase program for up to $500 million of Denbury common shares, as approved by the Company's Board. The program has no pre-established ending date, and may be suspended or discontinued at any time. The Company is not obligated to repurchase any dollar amount or specific number of shares of its common stock under the program. Between early October 2011 and October 31, 2011, we repurchased 10,990,939 shares of Denbury common stock (approximately 2.7% of our outstanding shares of common stock at September 30, 2011) for $149.3 million, or $13.58 per share under this share repurchase program.

Item 6. Exhibits

Exhibit	Description
4.1	Sixth Amendment to Credit Agreement dated as of March 9, 2010, dated as of September 1, 2011, among Denbury Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the financial institutions party thereto (incorporated by reference as Exhibit 10.1 of our Form 8-K filed on September 8, 2011).
10.1*	Officer Resignation Agreement dated as of September 29, 2011.

31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101*	Interactive Data Files

* Filed herewith.

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DENBURY RESOURCES INC.

SIGNATURES

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

DENBURY RESOURCES INC.

By:	/s/ Mark C. Allen Mark C. Allen Senior Vice President, Chief Financial Officer, Treasurer, and Assistant Secretary
By:	/s/ Alan Rhoades Alan Rhoades Vice President and Chief Accounting Officer

Date: November 8, 2011