GOODRICH PETROLEUM CORP
Form 10-Q
November 06, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2014

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	76-0466193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

801 Louisiana, Suite 700

Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 780-9494

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

Indicate by check mark whether the registrant 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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.

Large accelerated filer ¨	Accelerated filer x
Non-accelerated filer ¨	Smaller reporting company ¨

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

The number of shares outstanding of the Registrant's common stock as of October 31, 2014 was 44,434,222.

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PART 1 – FINANCIAL INFORMATION

Item 1—Financial Statements

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	September 30, 2014 (unaudited)	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$2,215	$49,220
Restricted cash	51,816	51,816
Accounts receivable, trade and other, net of allowance	8,844	3,113
Accrued oil and natural gas revenue	20,975	19,455
Fair value of oil and natural gas derivatives	7,669	6,187
Inventory	1,318	2,076
Prepaid expenses and other	1,428	1,278
Total current assets	94,265	133,145
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	2,092,546	1,838,220
Furniture, fixtures and equipment	7,589	6,960
	2,100,135	1,845,180
Less: Accumulated depletion, depreciation and amortization	(1,200,297)	(1,021,863)
Net property and equipment	899,838	823,317
Fair value of oil and natural gas derivatives	2,167	1,396
Deferred tax assets	2,599	665
Deferred financing cost and other	13,340	15,690
TOTAL ASSETS	$1,012,209	$974,213
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$93,076	$50,551
Accrued liabilities	64,873	48,603
Accrued abandonment costs	149	99
Deferred tax liabilities current	2,599	665
Fair value of oil and natural gas derivatives	—	4,341
Current portion of debt	45,124	49,663
Total current liabilities	205,821	153,922
Long-term debt	564,340	435,866
Accrued abandonment costs	21,972	20,757
Fair value of oil and natural gas derivatives	1,347	2,371
Transportation obligation	4,142	4,774

Deferred tax liabilities noncurrent	—	—
Total liabilities	797,622	617,690
Commitments and contingencies (See Note 7)		
STOCKHOLDERS' EQUITY:		
Preferred stock: 10,000,000 shares $1.00 par value authorized:		
Series B convertible preferred stock, issued and outstanding 2,250,000 shares	2,250	2,250
Series C cumulative preferred stock, issued and outstanding 4,400 shares	4	4
Series D cumulative preferred stock, issued and outstanding 5,200 shares	5	5
Common stock: $0.20 par value, 100,000,000 shares authorized; issued and outstanding 44,433,930 and 44,258,824 shares, respectively	8,887	8,852
Additional paid in capital	1,064,008	1,056,378
Retained earnings (accumulated deficit)	(860,567)	(710,966)
Total stockholders' equity	214,587	356,523
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,012,209	$974,213

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, Except Per Share Amounts)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
REVENUES:				
Oil and natural gas revenues	$54,880	$56,824	$159,953	$151,949
Other	(6)	337	43	781
	54,874	57,161	159,996	152,730
OPERATING EXPENSES:				
Lease operating expense	6,745	7,072	22,674	20,169
Production and other taxes	2,869	2,462	7,293	7,964
Transportation and processing	2,121	2,768	6,832	7,841
Depreciation, depletion and amortization	36,011	33,320	95,325	102,807
Exploration	897	4,115	5,564	16,961
Impairment	85,339	—	85,339	—
General and administrative	8,312	8,294	26,707	25,326
Gain on sale of assets	—	(16)	—	(59)
Other	—	—	3,357	(91)
	142,294	58,015	253,091	180,918
Operating loss	(87,420)	(854)	(93,095)	(28,188)
OTHER INCOME (EXPENSE):				
Interest expense	(12,645)	(12,679)	(36,274)	(39,079)
Interest income and other	6	(1)	26	18
Loss on early extinguishment of debt	—	(4,792)	—	(4,792)
Gain (loss) on derivatives not designated as hedges	20,348	(8,759)	2,034	350
	7,709	(26,231)	(34,214)	(43,503)
Loss before income taxes	(79,711)	(27,085)	(127,309)	(71,691)
Income tax benefit	—	—	—	—
Net loss	(79,711)	(27,085)	(127,309)	(71,691)
Preferred stock dividends	7,431	5,705	22,292	11,173
Net loss applicable to common stock	$(87,142)	$(32,790)	$(149,601)	$(82,864)
PER COMMON SHARE				
Net loss applicable to common stock - basic	$(1.96)	$(0.89)	$(3.37)	$(2.26)
Net loss applicable to common stock - diluted	$(1.96)	$(0.89)	$(3.37)	$(2.26)
Weighted average common shares outstanding - basic	44,430	36,732	44,337	36,706
Weighted average common shares outstanding - diluted	44,430	36,732	44,337	36,706

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(127,309)	$(71,691)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	95,325	102,807
Impairment	85,339	—
Unrealized gain on derivatives not designated as hedges	(7,617)	(3,762)
Amortization of leasehold costs	2,831	13,192
Share based compensation (non-cash)	6,674	5,211
Gain on sale of assets	—	(59)
Exploration cost	785	658
Amortization of finance cost, debt discount and accretion	7,995	10,005
Loss on early extinguishment of debt	—	4,792
Amortization of transportation obligation	601	920
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	(5,732)	3,447
Accrued oil and natural gas revenue	(1,520)	(3,537)
Inventory	758	200
Prepaid expenses and other	562	(114)
Accounts payable	42,525	(19,275)
Accrued liabilities	(6,049)	(1,953)
Net cash provided by operating activities	95,168	40,841
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(238,313)	(195,624)
Proceeds from sale of assets	625	449
Net cash used in investing activities	(237,688)	(195,175)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from bank borrowings	247,000	274,800
Principal payments of bank borrowings	(129,000)	(227,000)
Restricted cash	—	(109,250)
Proceeds from preferred stock offering	—	230,822
Preferred stock dividends	(22,292)	(11,173)
Debt issuance costs	(334)	(3,440)
Exercise of stock options and warrants	141	322
Other	—	(34)
Net cash provided by financing activities	95,515	155,047
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(47,005)	713

CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	49,220	1,188
CASH AND CASH EQUIVALENTS, END OF PERIOD	$2,215	$1,901

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—Description of Business and Significant Accounting Policies

Goodrich Petroleum Corporation (together with its subsidiary, "we," "our," or the "Company") is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale, (ii) South Texas, which includes the Eagle Ford Shale Trend and (iii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Trends.

Principles of Consolidation— The consolidated financial statements of the Company included in this Quarterly Report on Form 10-Q have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") and accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") has been condensed or omitted. The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiary. Intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Certain data in prior periods' financial statements have been adjusted to conform to the presentation of the current period. We have evaluated subsequent events through the date of this filing.

Use of Estimates—Our management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with US GAAP.

Cash and Cash Equivalents—Cash and cash equivalents includes cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at the date of purchase.

Restricted Cash—Restricted cash at September 30, 2014 of $51.8 million is held in escrow for the repurchase of the remaining outstanding principal amount on our 5% Convertible Senior Notes due 2029. See Note 3.

Property and Equipment—As of September 30, 2014, we had interests in oil and natural gas properties totaling $898.2 million, net of accumulated depletion, which we account for under the successful efforts method. Under this method, costs of acquiring unproved and proved oil and natural gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases. Development costs are capitalized, including the costs of unsuccessful development wells.

Impairment—We periodically assess our long-lived assets recorded in oil and natural gas properties on the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value, which is computed using level 3 inputs such as discounted cash flow models or valuations, based on estimated future commodity prices and our various operational assumptions. An evaluation is performed on a field-by-field basis at least annually or whenever changes in facts and circumstances indicate that our oil and natural gas properties may be impaired.

During the third quarter of 2014 there was an indication, due to declines in estimated proved reserves, the carrying amount of certain of our natural gas properties was not recoverable from future cash flows. We recorded an impairment of $85.3 million for the three and nine months ended September 30, 2014. The impairment charge reduced the fields' carrying value to an estimated fair value of $25.0 million. Estimated fair value was measured using the income approach with Level 3 inputs. No impairments were recorded for the three months ended March 31, 2014 or June 30, 2014.

Fair Value Measurement—Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, our credit risk.

We use various methods, including the income approach and market approach, to determine the fair values of our financial instruments that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments into three levels (levels 1, 2 and 3) based on our assessment of the availability of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels.

Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 Inputs— unadjusted quoted market prices in active markets for identical assets or liabilities. Included in this level are our senior notes;
Level 2 Inputs— quotes which are derived principally from or corroborated by observable market data. Included in this level are our bank debt and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties; and
Level 3 Inputs— unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on our various assumptions and future commodity prices. Included in this level would be acquisitions and impairments of oil and natural gas properties.
The following table summarizes the fair value of our financial instruments and long lived assets that are recorded or disclosed at fair value classified in each level as of September 30, 2014:

	Fair Value Measurements as of September 30, 2014 (in thousands)			
Description	Level 1	Level 2	Level 3	Total
Recurring Fair Value Measurements				
Commodity Derivatives (see Note 6)	$—	$8,489	$—	$8,489
Debt (see Note 3)	(508,262)	(118,000)	—	(626,262)
Total recurring fair value measurements	$(508,262)	$(109,511)	$—	$(617,773)
Nonrecurring Fair Value Measurements				
Impaired Natural Gas Properties	$—	$—	$24,952	$24,952

As of September 30, 2014 and December 31, 2013, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

Depreciation—Depreciation and depletion of producing oil and natural gas properties is calculated using the units-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs. Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in operating income. Depreciation of furniture, fixtures and equipment, consisting of office furniture, computer hardware and software and leasehold improvements, is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

Transportation Obligation—We entered into a natural gas gathering agreement with an independent service provider, effective July 27, 2010. The agreement is scheduled to remain in effect for a period of ten years and requires the

service provider to construct pipelines and facilities to connect our wells to the service provider's gathering system in our Eagle Ford Shale Trend area of South Texas. In compensation for the services, we agreed to pay the service provider 110 percent of the total capital cost incurred by the service provider to construct new pipelines and facilities. The service provider bills us for 20 percent of the accumulated unpaid capital costs annually.

We accounted for the agreement by recording a long-term asset, included in "Deferred financing cost and other" on the Consolidated Balance Sheets. The asset is being amortized using the units-of-production method and the amortization expense is included in "Transportation and processing" on the Consolidated Statements of Operations. The related current and long-term liabilities are presented on the Consolidated Balance Sheets in "Accrued liabilities" and "Transportation obligation", respectively.

Asset Retirement Obligations—We follow the accounting standard related to accounting for asset retirement obligations. These obligations are related to the abandonment and site restoration requirements that result from the exploration and development of our oil and gas properties. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and

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a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in "Depreciation, depletion and amortization" on our Consolidated Statements of Operations. See Note 2.

Revenue Recognition—Oil and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. We record a liability or an asset for natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At September 30, 2014 and December 31, 2013, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

Derivative Instruments—We use derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. We offset the fair value of our asset and liability positions with the same counterparty for each commodity type. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. All our realized gain or losses on our derivative contracts are the result of cash settlements. We have not designated any of our derivative contracts as hedges, accordingly; changes in fair value are reflected in earnings. See Note 6.

Earnings Per Share—Basic loss per common share is computed by dividing net loss available to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted loss per common share is computed by dividing net loss available to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive stock options and restricted stock calculated using the Treasury Stock method and the potential dilutive effect of the conversion of shares associated with 5.375% Series B Convertible Preferred Stock ("Series B Preferred Stock"), 3.25% Convertible Senior Notes due 2026 (the "2026 Notes"), 5% Convertible Senior Notes due 2029 (the "2029 Notes") and 5% Convertible Senior Notes due 2032 (the "2032 Notes"). See Note 4.

Commitments and Contingencies—Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, when probable of realization, are separately recorded and are not offset against the related environmental liability.

Guarantees—On March 2, 2011, we issued and sold $275 million aggregate principal amount of our 8.875% Senior Notes due 2019 (the "2019 Notes"). Upon issuance of the guarantee related to the 2019 Notes, our subsidiary also became a guarantor on our outstanding 2029 Notes and our 2026 Notes, pursuant to the respective indentures governing the 2029 Notes and 2026 Notes. On August 26, 2013 and October 1, 2013, we issued $109.25 million and $57.0 million, respectively, aggregate principal amount of our 2032 Notes, which are also guaranteed by our subsidiary pursuant to the terms of the indenture governing the 2032 Notes. The 2019 Notes, 2029 Notes, 2026 Notes and 2032 Notes are guaranteed on a senior unsecured basis by our 100% owned subsidiary, Goodrich Petroleum Company, L.L.C.

Goodrich Petroleum Corporation, as the parent company (the “Parent Company”), has no independent assets or operations. The guarantees are full and unconditional, subject to customary exceptions pursuant to the indentures governing our 2019 Notes, 2026 Notes, 2029 Notes and 2032 Notes, as discussed below. The Parent Company has no other subsidiaries. In addition, there are no restrictions on the ability of the Parent Company to obtain funds from its subsidiary by dividend or loan. Finally, the Parent Company’s wholly-owned subsidiary does not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by the subsidiary without the consent of a third party.

Guarantees of the 2019 Notes will be released under certain circumstances, including in the event a Subsidiary Guarantor (as defined in the indenture governing the 2019 Notes) is sold or disposed of (whether by merger, consolidation, the sale of its capital stock or the sale of all or substantially all of its assets (other than by lease)) and whether or not the Subsidiary Guarantor is the surviving entity in such transaction to a person which is not the Parent Company or a Restricted Subsidiary of the Parent Company, such Subsidiary Guarantor will be released from its obligations under its Subsidiary Guarantee if the sale or other disposition does not violate the covenants described under “Limitation on Sales of Assets and Subsidiary Stock” in the indenture governing the 2019 Notes. In addition, a Subsidiary Guarantor will be released from its obligations under the indenture and its guarantee if such Subsidiary Guarantor ceases to guarantee any other indebtedness of the Parent Company or a Subsidiary Guarantor under a credit

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

facility, and is not a borrower under the Senior Secured Credit Agreement, provided no Event of Default (as defined in the indenture governing the 2019 Notes) has occurred and is continuing; or if the Parent Company designates such subsidiary as an Unrestricted Subsidiary and such designation complies with the other applicable provisions of the indenture or if such subsidiary otherwise no longer meets the definition of a Restricted Subsidiary; or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the 2019 Notes in accordance with the indenture.

Guarantees of the 2032 Notes, 2029 Notes and 2026 Notes will be released if the Subsidiary Guarantor no longer guarantees the 2019 Notes, if the Subsidiary Guarantor is dissolved or liquidated, if the Subsidiary Guarantor is no longer the Parent Company's subsidiary or upon satisfaction and discharge of the 2032 Notes, 2029 Notes or 2026 Notes in accordance with their respective indentures.

New Accounting Pronouncements

On August 27, 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-15, which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of the Company's ability to continue as a going concern within one year of the date the financial statements are issued. An entity must provide certain disclosures if conditions or events raise substantial doubt about the entity's ability to continue as a going concern. The ASU applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter, with early adoption permitted.

In May 2014, the FASB issued ASU 2014-09 that introduces a new five-step revenue recognition model in which an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU also requires disclosures sufficient to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers, including qualitative and quantitative disclosures about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. This standard is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. The Company is currently evaluating the new guidance to determine the impact it will have on its consolidated financial statements.

In April 2014, the FASB issued ASU 2014-08, which includes amendments that change the requirements for reporting discontinued operations and require additional disclosures about discontinued operations. Under the new guidance, only disposals representing a strategic shift in operations - that is, a major effect on the organization's operations and financial results should be presented as discontinued operations. Additionally, the ASU requires expanded disclosures about discontinued operations that will provide financial statement users with more information about the assets, liabilities, income, and expenses of discontinued operations. The new standard is effective in the first quarter of 2015 for public organizations with calendar year ends. Early adoption would be permitted for any annual or interim period for which an entity's financial statements have not yet been made available for issuance. The adoption of this guidance is not expected to have an impact on the Company's consolidated financial statements.

NOTE 2—Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the period ending September 30, 2014 is as follows (in thousands):

	September 30, 2014
Beginning balance at December 31, 2013	$ 20,856
Liabilities incurred	363
Revisions in estimated liabilities	50
Liabilities settled	—
Accretion expense	1,053
Dispositions	(201)
Ending balance	$ 22,121
Current liability	$ 149
Long term liability	$ 21,972

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3—Debt

Debt consisted of the following balances as of the dates indicated (in thousands):

	September 30, 2014			December 31, 2013		
	Principal	Carrying Amount	Fair Value (1)	Principal	Carrying Amount	Fair Value (1)
Senior Credit Facility	$118,000	$118,000	$118,000	$—	$—	$—
3.25% Convertible Senior Notes due 2026	429	429	341	429	429	429
5.0% Convertible Senior Notes due 2029 (2)	51,816	51,816	51,298	51,816	49,663	51,686
5.0% Convertible Senior Notes due 2032 (3)	169,921	164,219	176,123	167,405	160,437	171,863
8.875% Senior Notes due 2019	275,000	275,000	280,500	275,000	275,000	288,063
Total debt	$615,166	$609,464	$626,262	$494,650	$485,529	$512,041

(1) The carrying amount for the Second Amended and Restated Credit Agreement represents fair value as the variable interest rates are reflective of current market conditions. The fair value of the notes was obtained by direct market quotes within Level 1 of the fair value hierarchy.

(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was zero and $2.1 million as of September 30, 2014 and December 31, 2013, respectively.

(3) The debt discount is amortized using the effective interest rate method based upon a four year term through October 1, 2017, the first repurchase date applicable to the 2032 Notes. The debt discount was $5.7 million and $7.0 million as of September 30, 2014 and December 31, 2013, respectively.

The following table summarizes the total interest expense (contractual interest expense, accretion, amortization of debt discount and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

	Three Months Ended September 30, 2014		Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate
Senior Credit Facility	$1,332	5.3 %	$894	5.9 %	$2,368	6.9 %	$3,235	4.9 %
3.25% Convertible Senior Notes due 2026	4	3.3 %	3	3.3 %	11	3.3 %	10	3.3 %

5.0% Convertible Senior Notes due 2029	1,431	11.1	%	4,578	11.1	%	4,280	11.3	%	15,976	11.3	%
5.0% Convertible Senior Notes due 2032	3,551	8.7	%	877	8.7	%	10,634	8.7	%	877	8.7	%
8.875% Senior Notes due 2019	6,327	9.2	%	6,327	9.2	%	18,981	9.2	%	18,981	9.2	%
Total	$12,645			$12,679			$36,274			$39,079		

Senior Credit Facility

Total lender commitments under the Second Amended and Restated Credit Agreement (including all amendments, the "Senior Credit Facility") are $600 million subject to borrowing base limitation which as of September 30, 2014 was $250 million. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. In connection with the October 1, 2014 redetermination, the borrowing base remained at $250 million. The borrowing base will be reduced to $230 million upon closing of the sale of our non-core assets (see Note 8). Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, depending on borrowing base utilization. As of September 30, 2014, we had $118 million outstanding under the Senior Credit Facility. Substantially all our assets are pledged as collateral to secure the Senior Credit Facility.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used here, but not defined, have the meanings assigned to them in the Senior Credit Facility. In October 2014, we entered into a Twelfth Amendment which was effective as of September 30, 2014. Entering into the Twelfth amendment allowed us to remain in compliance with our financial

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covenants. The Twelfth Amendment to the Senior Credit Facility amended the EBITDAX annualized calculation. The primary financial covenants include:

Current Ratio of 1.0/1.0;
Interest Coverage Ratio of EBITDAX of not less than 2.5/1.0 for the trailing four quarters or when measured for the second, third and fourth quarters of 2014, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters. The interest for such period to apply solely to the cash portion of interest expense; and
Total Debt no greater than 4.0 times EBITDAX for the trailing four quarters. Total Debt used in such ratio to be reduced by the amount of any restricted cash held in an escrow account established for the benefit of the lenders and dedicated to the redemption or prepayment of the 2029 Notes; provided that such ratio, when measured for the third and fourth quarters of 2014 and first quarter of 2015, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters.
As used in connection with the Senior Credit Facility, Current Ratio is consolidated current assets (including current availability under the Senior Credit Facility, but excluding non-cash assets related to our derivatives) to consolidated current liabilities (excluding non-cash liabilities related to our derivatives, accrued capital expenditures and current maturities under the Senior Credit Facility).

As used in connection with the Senior Credit Facility, EBITDAX is earnings before interest expense, income tax, depreciation, depletion and amortization, exploration expense, stock based compensation and impairment of oil and natural gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives not designated as hedges but exclude unrealized gains (losses) from derivatives not designated as hedges.

We were in compliance with all the financial covenants of the Senior Credit Facility as of September 30, 2014.

8.875% Senior Notes due 2019

On March 2, 2011, we sold $275 million of our 2019 Notes. The 2019 Notes mature on March 15, 2019, unless earlier redeemed or repurchased. The 2019 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2019 Notes accrue interest at a rate of 8.875% annually, and interest is paid semi-annually in arrears on March 15 and September 15. The 2019 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

After March 15, 2015, we may redeem all or a portion of the 2019 Notes at redemption prices (expressed as percentages of principal amount) equal to (i) 104.438% for the twelve-month period beginning on March 15, 2015; (ii) 102.219% for the twelve-month period beginning on March 15, 2016 and (iii) 100.000% on or after March 15, 2017, in each case plus accrued and unpaid interest to the redemption date. In addition, prior to March 15, 2015, we may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2019 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem or retire such capital stock; (iii) sell assets, including the capital stock of our restricted subsidiaries; (iv) pay dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. These covenants are subject to a number of important exceptions and qualifications. At any time when the 2019 Notes are rated investment grade by both Moody’s Investors

Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indenture governing the 2019 Notes) has occurred and is continuing, many of these covenants will terminate.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of our 2029 Notes. The 2029 Notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. As of September 30, 2014, $51.8 million in aggregate principal amount of the 2029 Notes remain outstanding.

The 2029 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2029 Notes accrue interest at a rate of 5% annually, and interest is paid semi-annually in arrears on April 1 and October 1 of each year.

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On September 2, 2014, the Company notified the holders of $51.8 million of the 2029 Notes that they had an option to require the Company to purchase on October 1, 2014, all or a portion of such holders' notes at a price equal to par, plus any accrued and unpaid interest to, but not including, October 1, 2014. On September 30, 2014, the Company was notified that holders of $45.1 million of the 2029 Notes requested their notes be repurchased. Subsequent to September 30, 2014, the Company used the Restricted Cash held in escrow to repurchase $45.1 million of the 2029 Notes on October 1, 2014. Following the repurchase of the 2029 Notes, $6.7 million of the 2029 Notes remained outstanding. Accordingly, as of September 30, 2014, the $45.1 million repurchase amount of the 2029 Notes is reflected on our Consolidated Balance Sheets as a current liability and the remaining balance of $6.7 million is reflected as long term debt. The $6.7 million remaining in the escrow account was released to us on October 2, 2014.

The 2029 Notes are convertible into shares of our common stock at a rate equal to 28.8534 shares per $1,000 principal amount of 2029 Notes (equal to an initial conversion price of approximately $34.66 per share of common stock per share).

Investors may convert their 2029 Notes at their option at any time prior to the close of business on the second business day immediately preceding the maturity date under the following circumstances: (1) during any fiscal quarter (and only during such fiscal quarter), if the last reported sale price of our common stock is greater than or equal to 135% of the conversion price of the 2029 Notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter; (2) if the 2029 Notes have been called for redemption; or (3) upon the occurrence of one of specified corporate transactions. Investors may also convert their 2029 Notes at their option at any time beginning on September 1, 2029, and ending at the close of business on the second business day immediately preceding the maturity date.

We separately accounted for the liability and equity components of our 2029 Notes in a manner that reflected our nonconvertible debt borrowing rate when interest was recognized through September 30, 2014. The debt discount was amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount on the 2029 Notes was fully amortized as of September 30, 2014.

5% Convertible Senior Notes due 2032

We entered into separate, privately negotiated exchange agreements in 2013 under which we retired $166.7 million in aggregate principal amount of our outstanding 2029 Notes in exchange for the issuance of the 2032 Notes in an aggregate principal amount of $166.3 million. The 2032 Notes will mature on October 1, 2032.

Many terms of the 2032 Notes remain the same as the 2029 Notes they replaced, including the 5.0% annual cash interest rate and the conversion rate of 28.8534 shares of our common stock per $1,000 principal amount of 2032 Notes (equivalent to an initial conversion price of approximately $34.6580 per share of common stock), subject to adjustment in certain circumstances.

Unlike the 2029 Notes, the principal amount of the 2032 Notes accretes at a rate of 2% per year commencing August 26, 2013, compounding on a semi-annual basis, until October 1, 2017. The accreted portion of the principal is payable in cash upon maturity but does not bear cash interest and is not convertible into our common stock. Holders have the option to require us to purchase any outstanding 2032 Notes on each of October 1, 2017, 2022 and 2027, at a price equal to 100% of the principal amount plus the accretion thereon. Accretion of principal is and will be reflected as a non-cash component of interest expense on our statement of operations during the term of the 2032 Notes. We

recorded $0.8 million of accretion in the third quarter of 2014.

We have the right to redeem the 2032 Notes on or after October 1, 2016 at a price equal to 100% of the principal amount, plus accrued but unpaid interest and accretion thereon. The 2032 Notes also provide us with the option, at our election, to convert the new notes in whole or in part, prior to maturity, into the underlying common stock, provided the trading price of our common stock exceeds $45.06 (or 130% of the then applicable conversion price) for the required measurement period. If we elect to convert the 2032 Notes on or before October 1, 2016, holders will receive a make-whole premium.

We separately account for the liability and equity components of our 2032 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. We measured the debt component of the 2032 Notes using an effective interest rate of 8%. We attributed $158.8 million of the fair value to the 2032 Note to debt component which compared to the face results in a debt discount of $7.5 million which will be amortized through the first put date of October 1, 2017. Additionally, we recorded $24.4 million within additional paid-in capital representing the equity component of the 2032 Notes. A debt discount of $5.7 million remains to be amortized on the 2032 Notes as of September 30, 2014.

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3.25% Convertible Senior Notes Due 2026

At September 30, 2014, $0.4 million of the 2026 Notes remained outstanding. Holders may present to us for redemption the remaining outstanding 2026 Notes on December 1, 2016 and December 1, 2021.

Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

The 2026 Notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of 2026 Notes (equal to a “base conversion price” of approximately $65.94 per share) plus
b) an additional amount of shares per $1,000 of principal amount of 2026 Notes equal to the incremental share factor 2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the “base conversion price” and the denominator of which is the applicable stock price.

NOTE 4—Net Loss Per Common Share

Net loss applicable to common stock was used as the numerator in computing basic and diluted loss per common share for the three and nine months ended September 30, 2014 and 2013. The following table sets forth information related to the computations of basic and diluted loss per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Amounts in thousands, except per share data)			
Basic and Diluted loss per share:				
Net loss applicable to common stock	$(87,142)	$(32,790)	$(149,601)	$(82,864)
Weighted average shares of common stock outstanding	44,430	36,732	44,337	36,706
Basic and Diluted loss per share (1) (2) (3)	$(1.96)	$(0.89)	$(3.37)	$(2.26)
(1) Common shares issuable upon assumed conversion of convertible preferred stock or dividends paid were not presented as they would have been anti-dilutive.	3,588	3,588	3,588	3,588
(2) Common shares issuable upon assumed conversion of the 2026 Notes, 2029 Notes and 2032 Notes or interest paid were not presented as they would have been	4,997	6,311	4,997	6,311

anti-dilutive.

(3) Common shares issuable on assumed conversion of restricted stock and employee stock option were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	640	771	593	540

NOTE 5—Income Taxes

We recorded no income tax expense or benefit for the three and nine months ended September 30, 2014. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed, and as a result we continue to maintain a full valuation allowance for our net deferred assets as of September 30, 2014.

As of September 30, 2014, we have no unrecognized tax benefits. There were no significant changes to the calculation since December 31, 2013.

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NOTE 6—Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices and interest rates. We are currently not designating our derivative contracts for hedge accounting. All our realized gain or losses on our derivative contracts are the result of cash settlements. All gains and losses both realized and unrealized from our derivative contracts have been recognized in “Other income (expense)” on our Consolidated Statements of Operations.

The following table summarizes the realized and unrealized gains and losses we recognized on our oil and natural gas derivatives for the three and nine month periods ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Oil and Natural Gas Derivatives (in thousands)	2014	2013	2014	2013
Realized gain/(loss) on oil and natural gas derivatives	$227	$(3,647)	$(5,583)	$(3,412)
Unrealized gain/(loss) on oil and natural gas derivatives	20,121	(5,112)	7,617	3,762
Total gain/(loss) on oil and natural gas derivatives	$20,348	$(8,759)	$2,034	$350

Commodity Derivative Activity

We enter into swap contracts, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production. Our policy is that all hedges are approved by the Hedging Committee of our Board of Directors, and reviewed periodically by the Board of Directors. As of September 30, 2014, the commodity derivatives we used were in the form of:

(a) swaps, where we receive a fixed price and pay a floating price, based on NYMEX, Louisiana Light Sweet Crude (Argus) or specific transfer point quoted prices, and

(b) calls, where we grant the counter party the option to buy an underlying commodity at a specified strike price, within a certain period.

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Decreases in domestic crude oil and natural gas spot prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties. Neither our counterparties nor we require any collateral upon entering derivative contracts. We had exposure of $10.3 million in derivative fair value had our counterparties as a group been unable to fulfill their obligations as of September 30, 2014.

As of September 30, 2014, our open positions on our outstanding commodity derivative contracts, all of which were with Royal Bank of Canada, Bank of Montreal, JPMorgan Chase Bank, N.A., Merrill Lynch Commodities, Inc. and Wells Fargo Bank, N.A., were as follows:

Contract Type	Daily Volume	Total Volume	Fixed Price	Fair Value at September 30, 2014 (in thousands)
Natural gas swaps (MMBtu)				
2014	30,000	2,760,000	$4.18-5.06	$ 1,825
Natural gas calls (MMBtu)				
2015	20,000	7,300,000	$5.05-5.06	(734)
2016	20,000	7,320,000	$5.05-5.06	(1,101)
Oil swaps (BBL)				
2014	2,500	230,000	$90.95-98.02	578
2014 (LLS Argus)	1,300	119,600	$94.55	306
2015 (LLS Argus)	3,500	1,277,500	$94.55-98.10	7,615
			Total	$ 8,489

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each level as of September 30, 2014 (in thousands). We measure the fair value of our commodity derivative contracts by applying the

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income approach. See Note 1 “Description of Business and Significant Accounting Policies-Fair Value Measurement” for our discussion for inputs used and valuation techniques for determining fair values.

	September 30, 2014 Fair Value Measurements Using			
Description	Level 1	Level 2	Level 3	Total
Current Assets Commodity Derivatives	$—	$7,669	$ —	$7,669
Non-current Assets Commodity Derivatives	—	2,167	—	2,167
Current Liabilities Commodity Derivatives	—	—	—	—
Non-current Liabilities Commodity Derivatives	—	(1,347)	—	(1,347)
Total	$—	$8,489	$ —	$8,489

We enter into oil and natural gas derivative contracts under which we have netting arrangements with each counter party. The following table discloses and reconciles the gross amounts to the amounts as presented on the Statement of Financial Position for the periods ending September 30, 2014 and December 31, 2013.

	September 30, 2014			December 31, 2013		
Fair Value of Oil and Gas Derivatives (in thousands)	Gross Amount	Amount Offset	As Presented	Gross Amount	Amount Offset	As Presented
Derivative Current Asset	$8,157	$ (488)	$ 7,669	$6,658	$ (471)	$ 6,187
Derivative Non-current Asset	2,167	—	2,167	1,396	—	1,396
Derivative Current Liability	(488)	488	—	(4,812)	471	(4,341)
Derivative Non-current Liability	(1,347)	—	(1,347)	(2,371)	—	(2,371)
Total	$8,489	$ —	$ 8,489	$871	$ —	$ 871

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NOTE 7—Commitments and Contingencies

As of September 30, 2014, we did not have any changes in material commitments and contingencies, including outstanding and pending litigation.

NOTE 8—Subsequent Events

On November 3, 2014, the Company entered into a definitive purchase and sale agreement to sell our interest in the Beckville, North Minden and West Brachfield fields located in Panola and Rusk Counties, Texas for $61.0 million, subject to closing adjustments. The agreement is subject to customary terms and conditions with an effective date of July 1, 2014 and an estimated closing date of December 22, 2014. The Company plans to use the net proceeds from the sale to repay borrowings under our Senior Credit Facility.

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

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with our management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning our operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "predicts," "target," "goal," "pla "potential," "should," or similar expressions or variations on such expressions that convey the uncertainty of future events or outcomes. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; we undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risk and uncertainties:

planned capital expenditures;
future drilling activity;
our financial condition;
business strategy including our ability to successfully transition to more liquids-focused operations;
the market prices of oil and natural gas;
uncertainties about our estimated quantities of oil and natural gas reserves;
financial market conditions and availability of capital;
production;
hedging arrangements;
future cash flows and borrowings;
litigation matters;
pursuit of potential future acquisition opportunities;
sources of funding for exploration and development;
general economic conditions, either nationally or in the jurisdictions in which we are doing business;
legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign laws, and local environmental laws and regulations;
the creditworthiness of our financial counterparties and operation partners;
the securities, capital or credit markets;
our ability to repay our debt; and
other factors discussed below and elsewhere in this Quarterly Report on Form 10-Q and in our other public filings, press releases and discussions with our management.

For additional information regarding known material factors that could cause our actual results to differ from projected results please read the rest of this report and Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2013.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of properties primarily in (i) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale ("TMS"), (ii) South Texas, which includes the Eagle Ford Shale Trend and (iii) Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Trends.

We seek to increase shareholder value by growing our oil and natural gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and natural gas reserves and production on a cost-effective basis are the most important indicators of performance success for an independent oil and natural gas company.

We strive to increase our oil and natural gas reserves, production and cash flow through exploration and development activities. We develop an annual capital expenditure budget which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, when establishing our capital expenditure budget.

We place primary emphasis on our cash flow from operating activities ("operating cash flow") in managing our business. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses), non-cash general and administrative expenses and impairments.

Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as commodity prices for oil and natural gas. Such pricing factors are largely beyond our control; however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Business Strategy

Our business strategy is to provide long-term growth in reserves and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding reserve value through the timely development of our TMS, Eagle Ford Shale Trend, Haynesville Shale, and Cotton Valley Taylor Sand acreage. We regularly evaluate possible acquisitions of prospective acreage and oil and natural gas drilling opportunities.

Several of the key elements of our business strategy are as follows:

Develop existing property base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the lowest risk and the highest potential rate of return. We intend to develop our multi-year inventory of drilling locations on our acreage in the TMS, Eagle Ford Shale Trend and Haynesville Shale in order to develop our oil and natural gas reserves.

Increase our oil production. During the past three years, we have concentrated on increasing our crude oil production and reserves by investing and drilling in the TMS and Eagle Ford Shale Trend. We intend to take advantage of the current favorable sales price of oil compared to the relative sales price of natural gas, and continue to grow our oil production as a percentage of total production.

Expand acreage position in shale plays. As of September 30, 2014, we held approximately 326,000 net acres in the TMS in Southeastern Louisiana and Southwestern Mississippi. We continue to concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our

extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in areas that exhibit characteristics similar to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal non-core properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on maximizing cash flow margins. We intend to maximize operating cash flow by focusing on higher-margin oil development in the TMS and the Eagle Ford Shale Trend. In the current commodity price environment, our TMS and Eagle Ford Shale Trend assets offer more attractive rates of return on capital invested and cash flow margins than our natural gas assets.

Maintain financial flexibility. As of September 30, 2014, we had a borrowing base of $250 million under our $600 million Second Amended and Restated Credit Agreement (including all amendments, the “Senior Credit Facility”), on which only $118 million in borrowings was outstanding. We have historically funded growth through operating cash flow, debt, equity and equity-linked security issuances, divestments of non-core assets and by entering into strategic joint ventures.

We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including fixed price swaps, swaptions and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy.

Overview of Third Quarter 2014 Results

Third Quarter 2014 financial and operating results included:

- Our oil and condensate production for the third quarter of 2014 increased to 43% of our total production compared to 29% of our total production in the third quarter of 2013.
- We conducted drilling operations on 12 gross (7.2 net) wells in the third quarter of 2014, including 11 gross (6.6 net) wells in the TMS and 1 gross (0.7 net) Eagle Ford Shale Trend well. We added 9 gross (5.5 net) wells to production in the third quarter of 2014, which included 6 gross (3.5 net) wells in the TMS and 3 gross (2.0 net) wells in the Eagle Ford Shale.
- As of September 30, 2014, we had 3 gross (1.8 net) wells drilled and waiting on completion, in the TMS.

Primary Operating Areas

Tuscaloosa Marine Shale

We held approximately 459,000 gross (326,000 net) acres in the Tuscaloosa Marine Shale as of September 30, 2014. Our acreage is located in Southeastern Louisiana and in Southwestern Mississippi. During the nine months of 2014, we conducted drilling operations on 21 gross (12.9 net) wells in the TMS, of which 5 gross wells (0.3 net) wells were non-operated. As of September 30, 2014, we had 3 gross (1.8 net) TMS wells drilled and waiting on completion. Our net production volumes from our TMS wells represented approximately 20% of our total equivalent production on a Mcfe basis and approximately 45% of our total oil production for the third quarter of 2014.

During the nine months of 2014, we spent $197.2 million in the Tuscaloosa Marine Shale Trend, which included $22.2 million for leasehold costs.

Eagle Ford Shale Trend

During the nine months ended September 30, 2014, we continued drilling operations on our acreage in the Eagle Ford Shale Trend. We entered into the Eagle Ford Shale Trend in April 2010, with our leasehold position located in La Salle and Frio Counties, Texas. We held approximately 44,000 gross (30,000 net) acres as of September 30, 2014, all of which are either producing from or prospective for the Eagle Ford Shale. During the nine months of 2014, we conducted drilling operations on 6 gross (4.0 net) Eagle Ford Shale Trend wells. During the nine months of 2014, we spent $50.7 million on drilling and completion, leasehold and infrastructure capital expenditures in the Eagle Ford Shale Trend. Our net production volumes from our Eagle Ford Shale Trend wells represented approximately 28% of our total equivalent production on a Mcfe basis and approximately 53% of our total oil production for the third quarter of 2014.

Haynesville Shale Trend

Our relatively low risk development acreage in this trend is primarily centered in Rusk, Panola, Angelina and Nacogdoches Counties, Texas and DeSoto and Caddo Parishes, Louisiana. We hold approximately 111,000 gross (64,000 net) acres as of September 30, 2014 producing from and prospective for the Haynesville Shale Trend. Our net production volumes from our Haynesville Shale Trend wells represent approximately 38% of our total equivalent production on a Mcfe basis for the third quarter of 2014.

Results of Operations

For the three months ended September 30, 2014, we reported net loss applicable to common stock of $87.1 million, or $1.96 per basic and diluted share, on total revenue of $54.9 million as compared to net loss applicable to common stock of $32.8 million, or $0.89 per basic and diluted share, on total revenue of $57.2 million for the three months ended September 30, 2013.

For the nine months ended September 30, 2014, we reported net loss applicable to common stock of $149.6 million, or $3.37 per basic and diluted share, on total revenue of $160.0 million as compared to net loss applicable to common stock of $82.9 million, or $2.26 per basic and diluted share, on total revenue of $152.7 million for the nine months ended September 30, 2013.

The items that had the most material financial effect on us in three months ended September 30, 2014 compared to the same period in 2013 was impairment, loss on early extinguishment of debt and gain/loss on derivatives not designated as hedges. In the third quarter 2014 we recorded impairment related to certain natural gas properties which was partially offset by gains on our commodity derivatives as a result of decreasing oil and natural gas futures prices. Comparatively, the third quarter of 2013 did not contain impairment but reflected a loss for the early extinguishment debt related to the exchange transaction on our notes and a loss on our commodity derivatives as a result of increasing oil and natural gas prices in the period.

The following table reflects our summary operating information for the periods presented (in thousands except for price and volume data). Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as indicative of future results.

	Three Months Ended September 30,				Nine Months Ended September 30,			
(In thousands, except for price data)	2014	2013	Variance		2014	2013	Variance	
Revenues:								
Natural gas	$12,660	$17,167	$(4,507)	(26%)	$45,917	$49,643	$(3,726)	(8%)
Oil and condensate	42,220	39,657	2,563	6%	114,036	102,306	11,730	11%
Natural gas, oil and condensate	54,880	56,824	(1,944)	(3%)	159,953	151,949	8,004	5%
Operating revenues	54,874	57,161	(2,287)	(4%)	159,996	152,730	7,266	5%
Operating expenses	142,294	58,015	84,279	145%	253,091	180,918	72,173	40%
Operating loss	(87,420)	(854)	(86,566)	*	(93,095)	(28,188)	(64,907)	230%
Net loss applicable to common stock	(87,142)	(32,790)	(54,352)	166%	(149,601)	(82,864)	(66,737)	81%
Net Production:								
Natural gas (MMcf)	3,492	5,456	(1,964)	(36%)	11,880	14,506	(2,626)	(18%)
Oil and condensate (MBbls)	439	374	65	17%	1,161	974	187	19%
Total (Mmcfe)	6,125	7,698	(1,573)	(20%)	18,846	20,349	(1,503)	(7%)
Average daily production (Mcfe/d)	66,574	83,676	(17,102)	(20%)	69,032	74,538	(5,506)	(7%)

	Three Months Ended September 30,				Nine Months Ended September 30,			
(In thousands, except for price data)	2014	2013	Variance		2014	2013	Variance	
Average realized sales price per unit:								
Natural gas (per Mcf)	$3.63	$3.15	$0.48	15%	$3.87	$3.42	$0.45	13%
Natural gas (per Mcf) including realized derivatives	4.18	3.15	1.03	33%	4.03	3.42	0.61	18%
Oil and condensate (per Bbl)	96.22	106.11	(9.89)	(9%)	98.22	105.06	(6.84)	(7%)
Oil and condensate (per Bbl) including realized derivatives	92.34	96.36	(4.02)	(4%)	91.68	101.54	(9.86)	(10%)
	8.96	7.38	1.58	21%	8.49	7.47	1.02	14%

Average realized price (per Mcfe)

*Not meaningful

Revenues from Operations

Revenues from operations decreased by $2.3 million for the three months ended September 30, 2014 compared to the same period in 2013, reflecting a decrease in natural gas production volumes and lower average realized oil and condensate sales prices which decreased revenues by $10.8 million. This decrease in revenues was partially offset by an $8.9 million increase in revenues driven by increased oil and condensate production volumes and higher realized natural gas sales prices. We are focused on increasing oil production, which we are currently able to sell at a more favorable relative price than natural gas. For the three months ended September 30, 2014, 77% of our oil and natural gas revenue was attributable to oil sales compared to 70% for the three months ended September 30, 2013.

Revenues from operations increased by approximately $7.3 million for the nine months ended September 30, 2014 compared to the same period in 2013, reflecting an increase in oil and condensate production volumes and higher average realized natural gas sales prices which increased revenues by $24.8 million partially offset by lower natural gas volumes and lower realized oil and condensate prices which decreased revenues by $16.8 million. Operating revenues were also impacted by a $0.7 million decrease in Other revenues. For the nine months ended September 30, 2014, 71% of our oil and natural gas revenue was attributable to oil sales compared to 67% for the nine months ended September 30, 2013.

The difference in our realized prices inclusive of the effect of the realized gains and losses on our derivatives between the three and nine month periods ended September 30, 2014 and 2013 relates to our oil and natural gas swap contracts. In the three and nine months ended September 30, 2014, we had 30,000 MMBtu per day hedged at an average floor price of $4.76 per MMbtu and in the comparative periods of 2013 we did not have natural gas derivatives. In the three and nine months ended September 30, 2014, we had 3,800 Bbls of oil per day hedged at an average fixed price of $93.65 per Bbl and in the comparative periods of 2013, we had an average of 3,557 Bbls of oil per day hedged at an average fixed price of $94.60 per Bbl.

Operating Expenses

As described below, operating expenses increased $84.3 million to $142.3 million in three months ended September 30, 2014 and increased $72.2 million to $253.1 million in the nine months ended September 30, 2014, each compared to the same periods in 2013.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses (in thousands)	2014	2013	Variance		2014	2013	Variance	
Lease operating expenses	$6,745	$7,072	$(327)	(5%)	$22,674	$20,169	$2,505	12%
Production and other taxes	2,869	2,462	407	17%	7,293	7,964	(671)	(8%)
Transportation and processing	2,121	2,768	(647)	(23%)	6,832	7,841	(1,009)	(13%)
Exploration	897	4,115	(3,218)	(78%)	5,564	16,961	(11,397)	(67%)

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses per Mcfe	2014	2013	Variance		2014	2013	Variance	
Lease operating expenses	$1.10	$0.92	$0.18	20%	$1.20	$0.99	$0.21	21%
Production and other taxes	0.47	0.32	0.15	47%	0.39	0.39	—	0%
Transportation and processing	0.35	0.36	(0.01)	(3%)	0.36	0.39	(0.03)	(8%)
Exploration	0.15	0.53	(0.38)	(72%)	0.30	0.83	(0.53)	(64%)

Lease Operating Expense

Lease operating expense (“LOE’) during the three month period ended September 30, 2014 decreased compared to the three months ended September 30, 2013. The decrease was the result of a $1.0 million reduction in workover expense which was offset by a $0.7 million increase in operating expenses primarily associated with the wells we purchased in August 2013 and wells we brought online in the TMS. Workover expense in the third quarter of 2014 totaled $0.6 million which added $0.10 per Mcfe to unit expense compared to workover expense of $1.6 million in the third quarter of 2013 which added $0.21 per Mcfe to unit expense.

LOE for the nine months ended September 30, 2014 increased in comparison to the same period in 2013. The majority of the increase or $2.8 million was associated with the wells we purchased in August 2013 and wells we brought online in the TMS. The increase was slightly offset by a $0.2 million reduction in operating costs in the Eagle Ford Shale driven by a reduction in workover expense. Our LOE will generally trend higher as we add more oil wells to our well count in our active drilling areas. LOE in the first nine months of 2014 included workover expense of $3.9

million which added $0.21 per Mcfe to unit expense compared to workover expense of $4.3 million in the first nine months of 2013 which added $0.21 per Mcfe to unit expense.

Production and Other Taxes

Production and other taxes for the three months ended September 30, 2014 included production tax of $1.9 million and ad valorem tax of $0.9 million. During the comparable period in 2013, production and other taxes included production tax of $2.0 million and ad valorem tax of $0.5 million.

Production and other taxes for the nine months ended September 30, 2014 included production tax of $5 million and ad valorem tax of $2.3 million. During the comparable period in 2013, production and other taxes included production tax of $5.7 million and ad valorem tax of $2.3 million.

Production and other taxes increased in the third quarter of 2014 due to an increase in ad valorem taxes associated with new TMS and Eagle Ford Shale Trend wells. The decrease in production tax for nine month period is associated with lower oil production from our Eagle Ford Shale wells and lower tax rates on the TMS wells drilled in the state of Mississippi after July 1, 2013. The State of Mississippi has enacted an exemption from the existing 6% severance tax for horizontal wells drilled after July 1, 2013 with production commencing before July 1, 2018, which will be partially offset by a 1.3% local severance tax on such wells. The exemption is applicable until the earlier of (i) 30 months from the date of first sale of production or (ii) until payout of the well cost is

achieved. The net revenues from our wells drilled in our TMS acreage in Southwestern Mississippi have been favorably impacted by this exemption.

Transportation and Processing Expense

Transportation and processing expense decreased in the three months and nine months ended September 30, 2014 compared to the same period in 2013. The decrease is due to lower operated natural gas production, as our natural gas production incurs substantially all of our transportation and processing cost.

Exploration

The decrease in exploration expense for the three months and nine months ended September 30, 2014 compared to the same periods in 2013 is attributable to a $3.0 million and $10.4 million, respectively, decrease in leasehold amortization costs in both comparative periods. Leasehold amortization costs include lease expiration expense. The nine month period was also impacted by no seismic cost in the first nine months of 2014 compared to $1.0 million in the first nine months of 2013.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses (in thousands)	2014	2013	Variance		2014	2013	Variance	
Depreciation, depletion and amortization	$36,011	$33,320	$2,691	8 %	$95,325	$102,807	$(7,482)	(7 %)
Impairment	85,339	—	85,339	*	85,339	—	85,339	*
General and administrative	8,312	8,294	18	0 %	26,707	25,326	1,381	5 %
Other	—	—	—	—	3,357	(91)	3,448	*

	Three Months Ended September 30,				Nine Months Ended September 30,			
Operating Expenses per Mcfe	2014	2013	Variance		2014	2013	Variance	
Depreciation, depletion and amortization	$5.88	$4.33	$1.55	36%	$5.06	$5.05	$0.01	0 %
Impairment	13.93	—	13.93	*	4.53	—	4.53	*
General and administrative	1.36	1.08	0.28	26%	1.42	1.24	0.18	15%
Other	—	—	—	—	0.18	—	0.18	*

* – Not meaningful.

Depreciation Depletion and Amortization (“DD&A”)

DD&A expense for the three months ended September 30, 2014 increased as compared to the three months ended September 30, 2013 primarily related to the increase in volumes and DD&A rates associated with the continued development of the TMS. TMS production volumes in the third quarter of 2014 represented 19% of production for the quarter compared to 5% for the same period in 2013.

DD&A expense in the nine months ended September 30, 2014 compared to the same period in 2013 decreased as a result of lower DD&A rates in our Eagle Ford Shale Trend properties, offset by the increase in volumes and DD&A rates associated with the continued development of the TMS.

Impairment

We recorded impairment expense of $85.3 million in the three and nine months ended September 30, 2014. The impairment was recorded in relation to a decline in estimated proved reserves for certain of our natural gas producing properties as of September 30, 2014. We did not record impairment expense in the comparable periods of 2013.

General and Administrative (“G&A) Expense

G&A expense increased in the three and nine months ended September 30, 2014 compared to the same period in 2013. The increase reflects higher compensation expense and share-based compensation. Share-based compensation expense, which is a non-cash item, amounted to $2.0 million for the three months ended September 30, 2014, a $0.3 million increase over the same period in 2013. For the nine months ended September 30, 2014, share-based compensation totaled $6.7 million, a $1.5 million increase over the same period in 2013.

Other Expense

Other expense increased $3.4 million, for the nine month period ended September 30, 2014, due to a $2.8 million charge for gathering and marketing cost on non-operated Haynesville Shale wells. We are currently disputing this charge with the operator of the wells. In addition, a $0.6 million charge was recorded in relation to a decision handed down by the Louisiana Court of Appeals regarding a long standing working interest dispute on a property we no longer own.

Other Income (Expense)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
Other income (expense) (in thousands):	2014	2013	2014	2013
Interest expense	$(12,645)	$(12,679)	$(36,274)	$(39,079)
Interest income and other	6	(1)	26	18
Loss on early extinguishment of debt	—	(4,792)	—	(4,792)
Gain (loss) on derivatives not designated as hedges	20,348	(8,759)	2,034	350
Average funded borrowings adjusted for debt discount and accretion	$591,033	$540,889	$533,801	$566,416
Average funded borrowings	$595,531	$554,259	$540,258	$582,826

Interest Expense

Our interest expense decreased slightly in the three months ended September 30, 2014 compared to the same period in 2013 despite having a higher average funded borrowing level during the three months ended September 30, 2014. A decrease in non-cash interest expense caused interest expense to decrease for the third quarter of 2014. The decrease was offset by an increase in interest expense associated with higher funded borrowings during the third quarter of 2014. Non-cash interest expense for the three months ended September 30, 2014 totaled $2.7 million, compared to $3.2 million in the same period in 2013. Also effecting our interest expense reduction is the lowering of our effective interest rate on the 5% Convertible Senior Notes due 2032 (the “2032 Notes”) compared to the 5% Convertible Senior Notes due 2029 (the “2029 Notes”) that were exchanged in the second half of 2013.

Our interest expense decreased in the nine months ended September 30, 2014 compared to the same period in 2013 as a result of the lower average level of outstanding debt in the nine months ended September 30, 2014. The lower average debt was primarily related to the Senior Credit Facility maintaining a lower outstanding balance compared to the same period in 2013. In addition, our interest decreased as a result of the reduction in our effective interest rate due to the exchange of the 2029 Notes and the 2032 Notes that occurred in the second half of 2013. Non-cash interest of $8.0 million is included in the interest expense reported for the nine month period in 2014 compared to $10.0 million in 2013 comparative period.

Gain (loss) on Derivatives Not Designated as Hedges

Gain on derivatives not designated as hedges for the three months ended September 30, 2014 includes an unrealized gain of $20.1 million for the change of the fair value of our oil and natural gas derivative contracts and a realized gain

of $0.2 million on the settlement of our oil and natural gas derivatives. The unrealized gain consisted of a $19.4 million gain on our oil derivatives and a $0.7 million gain on our natural gas derivatives. The unrealized gain on oil and natural gas derivatives reflects the decrease in futures prices for the period.

Loss on derivatives not designated as hedges for the three months ended September 30, 2013 includes an unrealized loss of $5.1 million for the change of the fair value of our oil and natural gas derivative contracts and a realized loss of $3.7 million on the settlement of our oil derivatives. The unrealized loss consisted of a $5.9 million loss on our oil derivatives and a $0.8 million gain on our natural gas derivatives. The unrealized loss on oil derivatives reflects the increase in oil futures prices for the period partially offset by the realization of settled contracts, while the gain on the natural gas derivatives reflects the shorter maturity of the open contracts. Natural gas futures prices declined only slightly during the period. There were no natural gas derivative contract settlements during the period.

Gain on derivatives not designated as hedges for the nine months ended September 30, 2014 includes an unrealized gain of $7.6 million for the change of the fair value of our oil and natural gas derivative contracts and a realized loss of $5.6 million on the settlement of our oil and natural gas derivatives. The unrealized gain consisted of an $11.4 million gain on our oil derivatives and a $3.8 million loss on our natural gas derivatives. The unrealized gain on oil derivatives reflects the decrease in futures prices for the period.

Gain on derivatives not designated as hedges for the nine months ended September 30, 2013 includes an unrealized gain of $3.8 million for the change of the fair value of our oil and natural gas derivative contracts and a realized loss of $3.4 million on the settlement of our oil derivatives. The unrealized gain consisted of an $8.1 million gain on our natural gas derivatives and a $4.3 million loss on our oil derivatives. The gain reflects our net favorable position on the natural gas contracts we entered into in 2013 and the maturing of our swaption contract which is the only natural gas derivative that we had in place at year end 2012. The unrealized loss on oil derivatives reflects the increase in oil futures prices for the period partially offset by the realization of settled contracts.

We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts as we do not designate these contracts as hedges.

Income Tax Benefit

We recorded no income tax benefit for the three months and nine months ended September 30, 2014. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of September 30, 2014.

Adjusted EBITDAX (in thousands) (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net loss (US GAAP)	$(79,711)	$(27,085)	$(127,309)	$(71,691)
Exploration expense	897	4,115	5,564	16,961
Depreciation, depletion and amortization	36,011	33,320	95,325	102,807
Impairment	85,339	—	85,339	—
Stock compensation expense	2,026	1,737	6,674	5,211
Interest expense	12,645	12,679	36,274	39,079
Loss on early extinguishment of debt	—	4,792	—	4,792
Unrealized (gain) loss on derivatives not designated as hedges	(20,121)	5,112	(7,617)	(3,762)
Other items (2)	(6)	(15)	3,331	(168)
Adjusted EBITDAX	$37,080	$34,655	$97,581	$93,229

(1) Adjusted EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense, stock compensation expense and impairment of oil and gas properties. In calculating adjusted EBITDAX for this purpose, earnings include realized gains (losses) from derivatives but exclude unrealized gains (losses) from derivatives. Other excluded items include Interest income and other, Gain/loss on sale of assets, Gain/loss on early extinguishment of debt and other expense.

(2) Other items include interest income, gain on sale of assets and other expense.

Management believes adjusted EBITDAX is a good financial indicator of our ability to internally generate operating funds. Adjusted EBITDAX should not be considered an alternative to net income, as defined by US GAAP. Management believes that this non-US GAAP financial measure provides useful information to investors because it is

monitored and used by our management and widely used by professional research analysts in the valuation and investment recommendations of companies within the oil and gas exploration and production industry.

Liquidity and Capital Resources

Overview

Our primary sources of cash during the third quarter of 2014 were from cash on hand, cash flow from operating activities and borrowings under our Senior Credit Facility. We used cash primarily to fund our capital spending program, pay interest on outstanding debt, and pay preferred stock dividends. We expect to finance our estimated capital expenditures for the remainder of 2014 through a combination of cash from operating activities and borrowings under our Senior Credit Facility.

We have in place a $600 million Senior Credit Facility, entered into with a syndicate of U.S. and international lenders. As of September 30, 2014, we had a $250 million borrowing base with $118 million in outstanding borrowings. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. In connection with the October 1, 2014 redetermination, the borrowing base remained at $250 million. Upon closing of the sale of our non-core Beckville, North Minden and West Brachfield assets our borrowing base will be reduced to $230 million. Interest on revolving borrowings under

the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, depending on borrowing base utilization. Substantially all of our assets are pledged as collateral to secure the Senior Credit Facility. We were in compliance with existing covenants under the Senior Credit Facility at September 30, 2014.

As of September 30, 2014, we held $51.8 million in an escrow account to provide for the repurchase of the remaining outstanding principal amount of our 2029 Notes. Pursuant to the terms of our Senior Credit Facility, the funding of this escrow account automatically extended the maturity of the Senior Credit Facility to February 25, 2016. The $51.8 million in escrow as of September 30, 2014 is reflected in our financial statements as Restricted Cash. Subsequent to September 30, 2014, the Company used the funds in the escrow account to purchase $45.1million of the 2029 Notes on October 1, 2014. Following the purchase of $45.1 million of the 2029 Notes, $6.7 million of the 2029 Notes remained outstanding. The $6.7 million remaining in the escrow account was released to us on October 2, 2014. Accordingly, the $45.1 million carrying value of the 2029 Notes that were purchased on October 1, 2014 is reflected on our September 30, 2014 financial statements as a current liability.

We continuously monitor our leverage position and coordinate our capital program with our expected cash flows and repayment of our projected debt. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:

- sale of non-core assets;
- joint venture partnerships in our TMS, Eagle Ford Shale Trend, and/or core Haynesville Shale acreage;
- availability of funds under our Senior Credit Facility; and
- issuance of debt or equity securities.

We have supported our cash flows with derivative contracts which covered approximately 76% of our oil and natural gas sales volumes for the nine months of 2014. We have also supported our cash flows by entering into derivative positions currently covering approximately 81% of our projected oil and natural gas sales volumes for the remainder of 2014. See Note 6—“Derivative Activities” in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Cash Flows

The following table presents our comparative cash flow summary for the periods reported (in thousands):

	Nine Months Ended September 30,		
	2014	2013	Variance
Cash flow statement information:			
Net cash:			
Provided by operating activities	$95,168	$40,841	$54,327
Used in investing activities	(237,688)	(195,175)	(42,513)
Provided by financing activities	95,515	155,047	(59,532)
Increase (decrease) in cash and cash equivalents	$(47,005)	$713	$(47,718)

Operating activities. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided

by operating activities for the nine months ended September 30, 2014 totaled $95.2 million up $54.3 million from the nine months ended September 30, 2013. The two main drivers for the increase include operating revenues and changes in working capital. Operating revenues increased $7.3 million for the nine months ended September 30, 2014 compared to the same period in 2013 reflecting the increase in oil production volumes and higher average realized natural gas sales prices. The $30.5 million change in working capital for the nine months ended September 30, 2014 results from timing of drilling and completion activity.

Investing activities. Net cash used in investing activities was $237.7 million for the nine months ended September 30, 2014, compared to $195.2 million for the nine months ended September 30, 2013. While we booked capital expenditures of approximately $259.5 million in the nine months ended September 30, 2014, we paid out cash amounts totaling $238.3 million in the nine months ended September 30, 2014. The difference is attributed to $22.5 million accrued at December 31, 2013 and paid in the nine months ended September 30, 2014 offset by $43.7 million in drilling and completion costs accrued at September 30, 2014. Capital expenditures in the first nine months of 2014 were offset by the receipt of $0.6 million in net proceeds, primarily from the sale of non-core assets located in East Texas.

Financing activities. Net cash provided in financing activities for the nine months ended September 30, 2014 consisted of net proceeds from borrowings under our Senior Credit Facility of $118 million, partially offset by preferred stock dividends of $22.3 million. We had $118 million in borrowings outstanding under our Senior Credit Facility as of September 30, 2014. In the nine months ended September 30, 2013, net cash provided in financing activities consisted of $230.8 million net proceeds from the offering of our Series C Preferred Stock and net proceeds from borrowings under our Senior Credit Facility of $47.8 million partially offset by preferred stock dividend payments of $11.2 million.

Debt consisted of the following balances as of the dates indicated (in thousands):

	September 30, 2014			December 31, 2013		
	Principal	Carrying Amount	Fair Value (1)	Principal	Carrying Amount	Fair Value (1)
Senior Credit Facility	$118,000	$118,000	$118,000	$—	$—	$—
3.25% Convertible Senior Notes due 2026	429	429	341	429	429	429
5.0% Convertible Senior Notes due 2029 (2)	51,816	51,816	51,298	51,816	49,663	51,686
5.0% Convertible Senior Notes due 2032 (3)	169,921	164,219	176,123	167,405	160,437	171,863
8.875% Senior Notes due 2019	275,000	275,000	280,500	275,000	275,000	288,063
Total debt	$615,166	$609,464	$626,262	$494,650	$485,529	$512,041

(1) The carrying amount for the Second Amended and Restated Credit Agreement represents fair value as the variable interest rates are reflective of current market conditions. The fair value of the notes was obtained by direct market quotes within Level 1 of the fair value hierarchy.

(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was zero and $2.1 million as of September 30, 2014 and December 31, 2013, respectively.

(3) The debt discount is amortized using the effective interest rate method based upon a four year term through October 1, 2017, the first repurchase date applicable to the 2032 Notes. The debt discount was $5.7 million and $7.0 million as of September 30, 2014 and December 31, 2013, respectively.

The following table summarizes the total interest expense (contractual interest expense, accretion, amortization of debt discount and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates):

Three Months Ended September 30, 2014		Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
Interest	Effective Interest	Interest	Effective Interest	Interest	Effective Interest	Interest	Effective Interest

	Expense	Rate		Expense	Rate		Expense	Rate		Expense	Rate	
Senior Credit Facility	$1,332	5.3	%	$894	5.9	%	$2,368	6.9	%	$3,235	4.9	%
3.25% Convertible Senior Notes due 2026	4	3.3	%	3	3.3	%	11	3.3	%	10	3.3	%
5.0% Convertible Senior Notes due 2029	1,431	11.1	%	4,578	11.1	%	4,280	11.3	%	15,976	11.3	%
5.0% Convertible Senior Notes due 2032	3,551	8.7	%	877	8.7	%	10,634	8.7	%	877	8.7	%
8.875% Senior Notes due 2019	6,327	9.2	%	6,327	9.2	%	18,981	9.2	%	18,981	9.2	%
Total	$12,645			$12,679			$36,274			$39,079		

For additional information on our financing activities, see Note 3 – “Debt” in the Notes to Consolidated Financial Statements under Part 1, Item I of this Form 10-Q.

Off-Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements for any purpose.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on consolidated financial statements which were prepared in accordance with generally accepted accounting principles in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We believe that certain accounting policies affect the more significant judgments and estimates used in the preparation of

our consolidated financial statements. Our Annual Report on Form 10-K for the year ended December 31, 2013, includes a discussion of our critical accounting policies and there have been no material changes to such policies during the nine months ended September 30, 2014.

Item 3—Quantitative and Qualitative Disclosures about Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. Our risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments we utilize include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments we utilize may vary from year to year and is governed by risk-management policies with levels of authority delegated by our Board of Directors. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and we may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding our accounting policies and additional information related to our derivative and financial instruments, see Note 1—“Description of Business and Significant Accounting Policies”, Note 3—“Debt” and “Note 6—Derivative Activities” in the Notes to Consolidated Financial Statements under Part 1, Item I of this Quarterly Report on Form 10-Q.

Commodity Price Risk

Our most significant market risk relates to fluctuations in crude oil and natural gas prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. In addition, a non-cash write-down of our oil and natural gas properties may be required if future commodity prices experience a sustained and significant decline. Below is a sensitivity analysis of our commodity-price-related derivative instruments.

As of September 30, 2014, we had derivative instruments in place for 2014 of 3,800 Bbls per day (crude oil) and 30,000 Mmbtu per day (natural gas). At September 30, 2014, we have a net asset derivative position of $8.5 million related to these derivative instruments. Utilizing actual derivative contractual volumes a hypothetical 10% increase in oil and natural gas prices would have turned our derivative position to a net liability of $13.8 million, while a hypothetical 10% decrease in oil and natural gas prices would have increased our net derivative asset to $10.4 million. However, a gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Adoption of Comprehensive Financial Reform

The adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Item 4—Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of September 30, 2014, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1—Legal Proceedings

A discussion of current legal proceedings is set forth in Part I, Item 1 under Note 7—"Commitments and Contingencies" to the Notes to Consolidated Financial Statements in this Form 10-Q.

Item 1A—Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2013, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially affect our business, financial condition or future results.

Item 6—Exhibits

3.1	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Acquisition II, Inc., dated January 31, 1997 (Incorporated by reference to Exhibit 3.1 B of the Company's Third Amended Registration Statement of Form S-1 (Registration No. 333-47078) filed on December 8, 2000).
3.2	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated March 12, 1998 (Incorporated by reference to Exhibit 3.2 of the Company's Annual Report on Form 10-K (File No. 001-12719) for the year ended December 31, 1997).
3.3	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated May 9, 2002 (Incorporated by reference to Exhibit 3.4 of the Company's Current Report on Form 8-K (File No. 001-12719) filed on December 3, 2007).
3.4	Certificate of Amendment of Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated May 30, 2007 (Incorporated by reference to Exhibit 3.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on August 9, 2007).
3.5	Bylaws of the Company, as amended and restated (Incorporated by reference to Exhibit 3.2(i) of the Company's Form 8-K (File No. 001-12719) filed on February 19, 2008).
3.6	Certificate of Designation of 5.375% Series B Cumulative Convertible Preferred Stock (Incorporated by reference to Exhibit 1.1 of the Company's Form 8-K (File No. 001-12719) filed on December 22, 2005).
3.7	Certificate of Designation with respect to the 10.00% Series C Cumulative Preferred Stock (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K (File No. 001-12719) filed on April 10, 2013).
3.8	Certificate of Designation with respect to the 9.75% Series D Cumulative Preferred Stock (Incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K (File No. 001-12719) filed on August 19, 2013).
10.1*	Eleventh Amendment to the Second Amended and Restated Credit Agreement dated August 4, 2014 among Goodrich Petroleum Company LLC. and Wells Fargo Bank National Association as administrative agent and the lenders thereto.
10.2*	Twelfth Amendment to the Second Amended and Restated Credit Agreement dated September 30, 2014 among Goodrich Petroleum Company LLC. and Wells Fargo Bank National Association as administrative

agent and the lenders thereto.

31.1* Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1** Certification by Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2** Certification by Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS* XBRL Instance Document

101.SCH* XBRL Schema Document

101.CAL* XBRL Calculation Linkbase Document

101.LAB* XBRL Labels Linkbase Document

101.PRE* XBRL Presentation Linkbase Document

101.DEF* XBRL Definition Linkbase Document

*Filed herewith
**Furnished herewith

SIGNATURES

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

GOODRICH PETROLEUM CORPORATION

(Registrant)

Date: November 6, 2014 By: /S/ Walter G. Goodrich
Walter G. Goodrich
Vice Chairman & Chief Executive Officer

Date: November 6, 2014 By: /S/ Jan L. Schott
Jan L. Schott
Senior Vice President & Chief Financial Officer