Jones Energy, Inc.
Form 10-Q
November 08, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2013

or

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

Commission file number 001-36006

Jones Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**80-0907968**
(State or other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification Number)

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
(512) 328-2953
(Address, including zip code, and telephone number, including area code, of Registrant s principal executive offices)

Robert J. Brooks

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
(512) 328-2953

(Address, including zip code, and telephone number, including area code, of Agent for service)

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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 o

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer x	Smaller reporting company o
		(Do not check if a 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 o No x

On November 6, 2013, the Registrant had 12,526,580 shares of Class A common stock outstanding and 36,836,333 shares of Class B common stock outstanding.

JONES ENERGY, INC.

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PART 1 FINANCIAL INFORMATION

Item 1. Financial Statements

Jones Energy, Inc.

Consolidated Balance Sheets (Unaudited)

(in thousands of dollars)		**September 30, 2013**		**December 31, 2012**
Assets				
Current assets				
Cash	$	23,055	$	23,726
Accounts receivable, net				
Oil and gas sales		52,766		29,684
Joint interest owners		23,280		21,876
Other		818		4,590
Other current assets		1,687		1,088
Commodity derivative assets		14,681		17,648
Total current assets		116,287		98,612
Oil and gas properties, net, at cost under the successful efforts method		1,080,054		1,007,344
Other property, plant and equipment, net		2,479		3,398
Commodity derivative assets		26,591		25,199
Other assets		15,345		16,133
Deferred tax assets		359		
Total assets	$	1,241,115	$	1,150,686
Liabilities and Stockholders / Members Equity				
Current liabilities				
Trade accounts payable	$	58,516	$	38,036
Oil and gas sales payable		63,858		45,860
Accrued liabilities		7,796		3,873
Deferred tax liabilities		17		61
Asset retirement obligations		174		174
Commodity derivative liabilities		10,424		4,035
Total current liabilities		140,785		92,039
Long-term debt		438,000		610,000
Deferred revenue		14,886		
Commodity derivative liabilities		511		7,657
Asset retirement obligations		10,025		9,332
Deferred tax liabilities		2,138		1,876
Total liabilities		606,345		720,904
Commitments and contingencies (Note 10)				
Stockholders / members equity				
Members equity				429,782
Class A common stock, $0.001 par value; 12,526,580 shares authorized, issued and outstanding		13		
Class B common stock, $0.001 par value; 36,836,333 shares authorized, issued and outstanding		37		

Additional paid-in-capital		172,652		
Retained earnings		(821)		
Stockholders / members equity		171,881		429,782
Non-controlling interest		462,889		
Total stockholders / members equity		634,770		429,782
Total liabilities and stockholders / members equity	$	1,241,115	$	1,150,686

The accompanying notes are an integral part of these consolidated financial statements.

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Jones Energy, Inc.

Consolidated Statements of Operations (Unaudited)

(in thousands of dollars)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating revenues				
Oil and gas sales	$ 68,625	$ 31,803	$ 188,184	$ 105,426
Other revenues	226	132	673	660
Total operating revenues	68,851	31,935	188,857	106,086
Operating costs and expenses				
Lease operating	7,761	5,776	19,308	17,107
Production taxes	3,469	1,192	9,103	3,951
Exploration	853	84	1,458	265
Depletion, depreciation and amortization	30,529	21,229	82,552	58,251
Impairment of oil and gas properties				61
Accretion of discount	170	146	434	427
General and administrative (including non-cash compensation expense)	13,974	3,832	25,611	11,508
Total operating expenses	56,756	32,259	138,466	91,570
Operating income (expense)	12,095	(324)	50,391	14,516
Other income (expense)				
Interest expense	(6,879)	(5,716)	(22,712)	(17,868)
Net gain (loss) on commodity derivatives	(20,728)	(18,436)	4,444	20,122
Gain (loss) on sales of assets	(55)	205	(30)	1,561
Other income (expense), net	(27,662)	(23,947)	(18,298)	3,815
Income (loss) before income tax	(15,567)	(24,271)	32,093	18,331
Income tax provision				
Current	15		48	
Deferred	(359)	104	(141)	327
Total income tax provision	(344)	104	(93)	327
Net income (loss) including non-controlling interests	(15,223)	(24,375)	32,186	18,004
Net income (loss) attributable to non-controlling interests	(14,402)		33,007	
Net income (loss) attributable to controlling interests	$ (821)	$ (24,375)	$ (821)	$ 18,004
Earnings (loss) per share:				
Basic and diluted	$ (0.07)		$ (0.07)	
Weighted average shares outstanding:				
Basic and diluted	12,500		12,500	

The accompanying notes are an integral part of these consolidated financial statements.

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Jones Energy, Inc.

Consolidated Statement of Changes In Stockholders / Members Equity (Unaudited)

(amounts in thousands)	Common Stock Class A Shares	Common Stock Class A Value	Common Stock Class B Shares	Common Stock Class B Value	Members Equity	Additional Paid-in-Capital	Retained Earnings	Non-controlling Interest	Total Stockholders / Members Equity
Balance at December 31, 2012		$		$	$ 429,782	$	$	$	$ 429,782
Issuance of common stock	12,500	13	36,836	37					50
Proceeds from the sale of common stock						172,373			172,373
Reclassification of members contributions					(465,945)			465,945	
Stock-compensation expense					10,100	279			10,379
Distribution to members					(10,000)				(10,000)
Net income (loss)					36,063		(821)	(3,056)	32,186
Balance at September 30, 2013	12,500	$ 13	36,836	$ 37	$	$ 172,652	$ (821)	$ 462,889	$ 634,770

The accompanying notes are an integral part of these consolidated financial statements.

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Jones Energy, Inc.

Consolidated Statements of Cash Flows (Unaudited)

(in thousands of dollars)	Nine Months Ended September 30, 2013	2012
Cash flows from operating activities		
Net income	$ 32,186	$ 18,004
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation, and amortization	82,552	58,251
Impairment of oil and gas properties		61
Accretion of discount	434	427
Amortization of debt issuance costs	2,003	2,650
Stock compensation expense	10,379	425
Other non-cash compensation expense (Note 9)	2,592	
Amortization of deferred revenue	(114)	
Gain on commodity derivatives	(4,444)	(20,122)
Loss (gain) on sales of assets	30	(1,561)
Deferred income tax provision	(141)	327
Other - net	227	60
Changes in assets and liabilities		
Accounts receivable	(23,359)	26,143
Other assets	643	1,170
Accounts payable and accrued liabilities	15,577	(22,362)
Net cash provided by operations	118,565	63,473
Cash flows from investing activities		
Additions to oil and gas properties	(127,478)	(95,878)
Proceeds from sales of assets	629	9,151
Acquisition of other property, plant and equipment	(440)	(743)
Current period settlements of matured derivative contracts	7,680	21,778
Net cash used in investing	(119,609)	(65,692)
Cash flows from financing activities		
Proceeds from issuance of long-term debt		49,243
Repayment under long-term debt	(172,000)	(38,243)
Payment of debt issuance costs	(49)	(18)
Proceeds from sale of common stock, net of expenses of $15.1 million	172,422	
Net cash provided by financing	373	10,982
Net increase (decrease) in cash	(671)	8,763
Cash		
Beginning of period	23,726	6,136
End of period	$ 23,055	$ 14,899
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 19,442	$ 15,275
Change in accrued additions to oil and gas properties	26,826	(8,952)
Current additions to ARO	499	257
Deferred offering costs	60	
Noncash distributions to members (Note 9)	10,000	

The accompanying notes are an integral part of these consolidated financial statements.

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

1. Organization and Description of Business

Organization

Jones Energy, Inc. (Jones or the Company) was formed in March 2013 as a Delaware corporation to become a publicly traded entity and the holding company of Jones Energy Holdings, LLC (JEH LLC). As the sole managing member of JEH LLC, Jones Energy, Inc. is responsible for all operational, management and administrative decisions relating to JEH LLC s business and consolidates the financial results of JEH LLC and its subsidiaries.

JEH LLC was formed as a Delaware limited liability company on December 16, 2009 through investments made by the Jones family and through private equity funds managed by Metalmark Capital and Wells Fargo Energy Capital. JEH LLC acts as a holding company of operating subsidiaries that own and operate assets that are used in the exploration, development, production and acquisition of oil and natural gas properties.

A corporate reorganization and recapitalization occurred in connection with the Company s initial public offering (the Offering) which closed on July 29, 2013. The pre-Offering owners of JEH LLC converted their existing membership interests in JEH LLC into JEH LLC Units and amended the existing LLC agreement to, among other things, modify its equity capital to consist solely of JEH LLC Units. Jones Energy, Inc. became the sole managing member of JEH LLC. Two classes of common stock, Class A common stock and Class B common stock, were authorized in connection with the Offering. Only Class A common stock was offered to investors pursuant to the Offering. The Class B common stock is held by the pre-Offering owners of JEH LLC and can be exchanged (together with a corresponding number of JEH LLC Units) for shares of Class A common stock on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications and other similar transactions. As a result of the Offering, the pre-Offering owners retained 74.7% of the total economic interest in JEH LLC, but with no voting rights or management power over Jones, resulting in the Company reporting this ownership interest as a non-controlling interest. Prior to the the Offering, JEH LLC was the controlling interest in the Company; hence all of the net income (loss) earned prior to the Offering date is reflected in the net income (loss) attributable to non-controlling interests on the Consolidated Statement of Operations for the three and nine months ended September 30, 2013.

Description of Business

The Company is engaged in the acquisition, exploration, and production of oil and natural gas properties in the mid-continent U.S. The Company s assets are located within two distinct basins in the Texas Panhandle and Oklahoma, the Anadarko Basin and the Arkoma Basin, respectively, and are owned by JEH LLC and its operating subsidiaries. The Company operates in one industry segment and all of its operations are conducted in one geographic area of the United States. The Company is headquartered in Austin, Texas.

2. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The accompanying consolidated financial statements include Jones Energy, Inc. and all of its subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation.

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

These interim financial statements have not been audited. However, in the opinion of management, all adjustments consisting of only normal and recurring adjustments necessary for a fair statement of the financial statements have been included. As these are interim financial statements, they do not include all disclosures required for financial statements prepared in conformity with GAAP. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Accordingly, they do not include all disclosures required by GAAP and should be read in conjunction with our most recent audited consolidated financial statements included in Jones Energy, Inc. s final prospectus dated July 23, 2013 and filed with the SEC on July 25, 2013 pursuant to Rule 424(b) under the Securities Act of 1933, as amended.

Use of Estimates

In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent liabilities, and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Changes in estimates are recorded prospectively.

Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect the Company s estimates of depletion expense, impairment, and the allocation of value in our business combinations. Significant assumptions are also required in the Company s estimates of the net gain or loss on commodity derivative assets and liabilities and asset retirement obligations (ARO).

Oil and Gas Properties

The Company accounts for its oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas properties consisted of the following at September 30, 2013 and December 31, 2012:

(in thousands of dollars)	**September 30, 2013**	**December 31, 2012**
Mineral interests in properties		
Unproved	$ 107,971	$ 137,254
Proved	784,268	737,558
Wells and equipment and related facilities	526,930	389,727
	1,419,169	1,264,539

Less: Accumulated depletion and impairment		(339,115)		(257,195)
Net oil and gas properties	$	1,080,054	$	1,007,344

As of September 30, 2013 and December 31, 2012, there were no costs capitalized in connection with exploratory wells in progress.

The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. The Company did not capitalize any interest during the period ended September 30, 2013 as no projects lasted more than six months. Depletion of oil and gas properties amounted to $30.3 million and $81.9 million for the three and nine months ended September 30, 2013,

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

respectively, and $21.0 million and $57.7 million for the three and nine months ended September 30, 2012, respectively.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at September 30, 2013 and December 31, 2012:

(in thousands of dollars)	**September 30, 2013**	**December 31, 2012**
Leasehold improvements	$ 1,004	$ 983
Furniture, fixtures, computers and software	2,346	2,204
Vehicles	732	719
Aircraft		1,295
Land	62	62
Production Equipment	72	72
	4,216	5,335
Less: Accumulated depreciation and amortization	(1,737)	(1,937)
Net other property, plant and equipment	$ 2,479	$ 3,398

Other property, plant and equipment is depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from three years to ten years. Depreciation and amortization of other property, plant and equipment amounted to $0.2 million and $0.6 million during the three and nine months ended September 30, 2013, respectively, and $0.2 million and $0.6 million during the three and nine months ended September 30, 2012, respectively.

Commodity Derivatives

The Company records its commodity derivative instruments on the Consolidated Balance Sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized currently in earnings, unless specific hedge accounting criteria are met. During the three month period ended September 30, 2013, the Company elected not to designate any of its commodity price risk management activities as cash-flow or fair value hedges. The changes in the fair values of outstanding financial instruments are recognized as gains or losses in the period of change.

Although Jones does not designate its commodity derivative instruments as cash-flow hedges, management uses those instruments to reduce the Company s exposure to fluctuations in commodity prices related to its natural gas and oil production. Net gains and losses, at fair value, are included on the Consolidated Balance Sheet as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of commodity derivative contracts are recorded in earnings as they occur and are included in other income (expense) on the Consolidated Statement of Operations. See Note 4, Fair Value Measurement , for disclosure about the fair values of commodity derivative instruments.

Asset Retirement Obligations

A summary of the Company s ARO for the nine months ended September 30, 2013 is as follows:

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

(in thousands of dollars)		
Balance at December 31, 2012	$	9,506
Liabilities incurred		499
Accretion of discount		434
Liabilities settled due to sale of related properties		(4)
Liabilities settled due to plugging and abandonment		(437)
Change in estimate		201
Balance at September 30, 2013		10,199
Less: Current portion of ARO		(174)
Total long-term ARO at September 30, 2013	$	10,025

Income Taxes

Prior to the Offering, the Company was a limited liability company and not subject to federal income tax. Accordingly, no provision for federal income taxes was recorded prior to the Offering because the taxable income or loss was includable in the income tax returns of the individual partners and members. The Company was and still is subject to state income taxes as the State of Texas includes in its tax system a gross margin tax applicable to the Company, and an accrual for gross margin taxes is included in the financial statements when appropriate. In connection with the corporate reorganization, the Company became a corporation and is now subject to federal income taxes.

Based on management s analysis, the Company did not have any uncertain tax positions as of September 30, 2013 and December 31, 2012.

Tax Receivable Agreement

In conjunction with the Offering, the Company entered into a Tax Receivable Agreement (TRA) with JEH LLC and its existing owners. Upon any exchange of JEH LLC Units and Class B common stock of the Company held by JEH LLC s pre-Offering owners for Class A common stock of the Company, the TRA provides for the payment by Jones, directly to such exchanging owners, of 85% of the amount of cash savings in income or franchise taxes that Jones realizes as a result of (i) the tax basis increases resulting from the exchange of JEH LLC Units for shares of Class A common stock (or resulting from a sale of JEH LLC Units for cash) and (ii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The Company will retain the benefit of the remaining 15% of the cash savings. Liabilities under this agreement will be recognized upon the exchange of shares. As of September 30, 2013, there have been no exchanges.

Recent Accounting Developments

The following recently issued accounting pronouncements have or will be adopted by the Company:

Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB), issued authoritative guidance requiring entities to disclose both gross and net information about instruments and transactions eligible for offset arrangement. The additional disclosures enable users of the financial statements to evaluate the effect or potential effect of netting arrangements on an entity s financial position. These disclosure requirements are effective for interim and annual periods beginning after January 1, 2013. The Company has provided all required disclosures for the periods presented in the third quarter of 2013 as they pertain to its commodity derivative instruments (see Note 4, Fair

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

Value Measurement). These disclosure requirements did not affect the Company s operating results, financial position, or cash flows.

3. Acquisition of Properties

No significant property acquisitions that would qualify as business combinations occurred during the nine months ended September 30, 2013 and 2012.

On December 20, 2012, JEH LLC acquired certain oil and natural gas properties located in Texas for a purchase price of $251.9 million (referred to herein as the Chalker acquisition or Chalker). The acquired assets represented a strategic fit with the Company s existing Texas Panhandle properties and included both producing properties and undeveloped acreage. The purchase was financed with additional equity capital and long-term debt. In the second quarter of 2013, Jones made a final determination with the sellers as to the purchase price adjustments resulting in a final purchase price of $253.5 million. The final purchase price was allocated as follows:

Oil and gas properties		
Unproved	$	71,264
Proved		182,493
Asset retirement obligations		(293)
Total purchase price	$	253,464

This acquisition qualified as a business combination under ASC 805. The valuation to determine the fair value was principally based on the discounted cash flows of both the producing and undeveloped properties, including projected drilling and equipment costs, recoverable reserves, production streams, future prices and operating costs, and risk-adjusted discount rates reflective of the current market.

The unaudited pro forma results presented below have been prepared to include the effect of the acquisition on our results of operations for the three and nine months ended September 30, 2012. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on January 1, 2012 or to project our results of operations for any future date or period.

	Three Months Ended September 30, 2012			
(in thousands of dollars)		**Actual**		**Pro Forma**
Total operating revenue	$	31,935	$	43,384
Total operating expenses		32,259		33,185
Operating income (loss)		(324)		10,199

Net income (loss)	(24,375)	(13,852)

	Nine Months Ended September 30, 2012	
(in thousands of dollars)	Actual	Pro Forma
Total operating revenue	$ 106,086	$ 135,824
Total operating expenses	91,570	94,128
Operating income	14,516	41,696
Net income	18,004	45,184

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

4. Fair Value Measurement

Fair Value of Financial Instruments

The Company determines fair value amounts using available market information and appropriate valuation methodologies. Fair value is the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The Company enters into a variety of derivative financial instruments, which may include over-the-counter instruments, such as natural gas, crude oil, and natural gas liquid contracts. The Company utilizes valuation techniques that maximize the use of observable inputs, where available. If listed market prices or quotes are not published, fair value is determined based upon a market quote, adjusted by other market-based or independently sourced market data, such as trading volume, historical commodity volatility, and counterparty-specific considerations. These adjustments may include amounts to reflect counterparty credit quality, the time value of money, and the liquidity of the market.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have low default rates and equal credit quality. Therefore, an adjustment may be necessary to reflect the quality of a specific counterparty to determine the fair value of the instrument. The Company currently has all of its derivative positions placed and held by members of its lending group, which have strong credit quality.

Liquidity valuation adjustments are necessary when the Company is not able to observe a recent market price for financial instruments that trade in less active markets. Exchange traded contracts are valued at market value without making any additional valuation adjustments; therefore, no liquidity reserve is applied.

Valuation Hierarchy

Fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. A financial instrument s categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument s fair value. The three levels are defined as follows:

Level 1 Pricing inputs are based on published prices in active markets for identical assets or liabilities as of the reporting date. The Company does not classify any of its financial instruments as Level 1.

Level 2 Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, as of the reporting date. Contracts that are not traded on a recognized exchange or are tied to pricing transactions for which forward curve pricing is readily available are classified as Level 2 instruments. These include natural gas, crude oil and some natural gas liquids price swaps and natural gas basis swaps.

Level 3 Pricing inputs include significant inputs that are generally unobservable from objective sources. The Company classifies natural gas liquid swaps and basis swaps for which future pricing is not readily available as Level 3. The Company obtains estimates from

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

independent third parties for its open positions and subjects those to the credit adjustment criteria described above.

The financial instruments carried at fair value as of September 30, 2013 and December 31, 2012, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

(in thousands of dollars) Commodity Price Hedges	September 30, 2013 Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Current assets	$	$ 14,501	$ 180	$ 14,681
Long-term assets		24,431	2,160	26,591
Current liabilities		10,349	75	10,424
Long-term liabilities		511		511

(in thousands of dollars) Commodity Price Hedges	December 31, 2012 Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Current assets	$	$ 17,648	$	$ 17,648
Long-term assets		24,756	443	25,199
Current liabilities		2,992	1,043	4,035
Long-term liabilities		6,739	918	7,657

The following table represents quantitative information about Level 3 inputs used in the fair value measurement of the Company s commodity derivative contracts as of September 30, 2013.

Commodity Price Hedges	Fair Value	Quantitative Information About Level 3 Fair Value Measurements Valuation Technique	Unobservable Input	Range
Natural gas liquid swaps	$ 2,354	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures prices	$8.09 - $84.89 per barrel
Basis swaps	$ (89)	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Forward basis prices	$(0.17) - $0.05 per mmbtu

Significant increases / decreases in natural gas liquid futures prices in isolation would result in a significantly lower / higher fair value measurement. The following table presents the changes in the Level 3 financial instruments for the nine months ended September 30, 2013. Changes in fair value of Level 3 instruments represent changes in gains and losses for the periods that are reported in other income (expense). New contracts entered into during the year are generally entered into at no cost with changes in fair value from the date of agreement representing the entire fair value of the instrument. Transfers between levels are evaluated at the end of the reporting period.

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

(in thousands of dollars)

Balance at December 31, 2012, net	$	(1,519)
Purchases		
Settlements		(5)
Transfers to Level 2		260
Transfers to Level 3		(716)
Changes in fair value		4,245
Balance at September 30, 2013, net	$	2,265

Transfers from Level 3 to Level 2 represent all of the Company s natural gas liquids swaps for which observable forward curve pricing information has become readily available. Transfers to Level 3 represent basis swaps that were previously considered Level 2 but due to the unavailability of forward prices at the valuation date were classified as Level 3 as of September 30, 2013. There were no purchases in the period that resulted in changes to Level 3.

Offsetting Assets and Liabilities

As of September 30, 2013, the counterparties to our commodity derivative contracts consisted of six financial institutions. All of our counterparties or their affiliates are also lenders under our credit facility. Therefore, we are not generally required to post additional collateral under our derivative agreements.

Our derivative agreements contain set-off provisions that state that in the event of default or early termination, any obligation owed by the defaulting party may be offset against any obligation owed to the defaulting party.

We adopted the guidance requiring disclosure of both gross and net information about financial instruments eligible for netting in the balance sheet under our derivative agreements. The following table presents information about our commodity derivative contracts which are netted on our balance sheet as of September 30, 2013 and December 31, 2012:

(in thousands)	Gross Amounts of Recognized Assets / Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets / Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet	Net Amount
September 30, 2013					
Commodity derivative contracts					
Assets	45,843	(4,711)	41,132	140	41,272
Liabilities	(15,646)	4,711	(10,935)		(10,935)

December 31, 2012					
Commodity derivative contracts					
Assets	49,200	(7,831)	41,369	1,478	42,847
Liabilities	(17,928)	7,831	(10,097)	(1,595)	(11,692)

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and gas property acquired include the Company s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine

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the inception value of the Company s AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company s ARO represent a nonrecurring Level 3 measurement.

The Company reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. During the nine months ended September 30, 2013 and 2012, no significant impairment charges on the Company s proved properties were recorded. Additionally, the Company assessed its unproved properties for impairment as of September 30, 2013 and 2012 and no impairments were noted. In the event of an impairment, charges are recorded on the Consolidated Statement of Operations. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the Company s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. As such, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

The fair value measurement of Monarch shares (see Note 9, Monarch Investment) is based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value was measured using a market approach valuation technique. Significant inputs to the valuation include estimates of future revenue, and operating costs, and related valuation multiples. These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

5. Derivative Instruments and Hedging Activities

Jones had various commodity derivatives in place to offset uncertain price fluctuations that could affect its future operations as of September 30, 2013 and December 31, 2012, as follows:

Hedging Positions

		September 30, 2013			
		Low	**High**	**Weighted Average**	**Final Expiration**
Oil swaps	Exercise price	$ 81.00	$ 104.45	$ 89.26	
	Barrels per month	24,000	143,116	88,325	December 2017
Natural gas swaps	Exercise price	$ 3.52	$ 6.90	$ 4.97	
	mmbtu per month	430,000	1,110,000	726,337	December 2017
Basis swaps	Contract differential	$ (0.45)	$ (0.03)	$ (0.33)	

	mmbtu per month		320,000	570,000	399,000	March 2016
Natural gas liquids swaps	Exercise price	$	6.72	$ 97.13	$ 32.97	
	Barrels per month		2,000	144,973	40,705	December 2017

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Notes to Consolidated Financial Statements (Unaudited)

		December 31, 2012			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 81.00	$ 104.45	$ 89.60	
	Barrels per month	24,000	143,116	89,323	December 2017
Natural gas swaps	Exercise price	$ 3.52	$ 6.90	$ 4.96	
	mmbtu per month	430,000	1,110,000	767,053	December 2017
Basis swaps	Contract differential	$ (0.65)	$ (0.03)	$ (0.31)	
	mmbtu per month	320,000	850,000	484,615	March 2016
Natural gas liquids swaps	Exercise price	$ 6.72	$ 97.13	$ 33.81	
	Barrels per month	2,000	144,973	55,616	December 2017

The Company recognized a net loss on derivative instruments of $20.7 million for the three months ended September 30, 2013 and a net gain of $4.4 million for the nine months ended September 30, 2013. The Company recognized a net loss of $18.4 million for the three months ended September 30, 2012 and a net gain of $20.1 million for the nine months ended September 30, 2012.

6. Long-Term Debt

The Company entered into two credit agreements dated December 31, 2009, with Wells Fargo Bank N.A, the Senior Secured Revolving Credit Facility (the Revolver) and the Second Lien Term Loan (the Term Loan) which were subsequently amended on November 18, 2011, November 5, 2012, December 20, 2012 and June 12, 2013. In connection with the November 2012 amendment, the maturity date of the Revolver was extended to November 5, 2017 and the maturity date of the Term loan was extended to May 5, 2018. In connection with the June 2013 amendment, the borrowing base on the Revolver was increased to $500.0 million. The Company s oil and gas properties are pledged as collateral against these credit agreements.

Terms of the two credit facilities require Jones to pay interest on the loan as LIBOR tranches mature and every three months on the remaining balance, with the principal and interest due on the loan maturity date. Prepayment of the principal balance of the Term Loan is allowed in whole or in part at any time with a premium payment due in certain conditions.

For the three and nine months ended September 30, 2013, the average interest rates under the Revolver were 2.74% and 3.04%, respectively, on average outstanding balances of $330.6 million and $406.7 million. For the same periods in 2012, the average interest rates were 3.39% and 3.23%, respectively, on average outstanding balances of $304.3 million and $299.0 million. Total interest and commitment fees under the two facilities were $6.2 million and $20.7 million for the three and nine months ended September 30, 2013, respectively, and $4.8 million and $15.2 million for the three and nine months ended September 30, 2012, respectively.

In connection with the initial public offering, the Company used the net proceeds to repay outstanding borrowings under the Revolver of $167.0 million.

The Revolver and Term Loans are categorized as Level 3 in the valuation hierarchy as the debt is not publicly traded and no observable market exists to determine the fair value; however, the carrying value of the Revolver and Term Loans approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

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The Revolver and Term Loans include covenants that require, among other things, restrictions on asset sales, distributions to members, and additional indebtedness, and the maintenance of certain financial ratios, including leverage, proven reserves to debt, and current ratio. At September 30, 2013 and December 31, 2012, the Company was in compliance with its financial debt covenants.

7. Stock-based Compensation

JEH LLC implemented a management incentive plan effective January 1, 2010, that provided membership-interest awards in JEH LLC to members of senior management (management units). These awards had various vesting schedules, and a portion of the management units vested in a lump sum at the Offering date. Both the vested and unvested management units were converted into JEH LLC Units and shares of Class B common stock at the Offering date. At the Offering date and at September 30, 2013 there were 559,061 unvested JEH LLC Units and shares of Class B common stock that will be convertible into a like number of shares of Class A common stock upon vesting.

Stock compensation expense of $9.9 million and $0.1 million for the three months ended September 30, 2013 and 2012, respectively, and $10.4 million and $0.4 million for the nine months ended September 30, 2013 and 2012, respectively, is included in general and administrative expense on the Consolidated Statements of Operations.

	JEH LLC Units	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2013	710,767	$ 3.62
Granted	911,654	$ 15.00
Forfeited	(167,239)	$ (3.62)
Vested	(896,121)	$ (10.68)
Unvested at September 30, 2013	559,061	$ 10.85

8. Earnings per Share

Basic earnings per share (EPS) is computed by dividing net income (loss) attributable to controlling interests by the weighted-average number of shares of Class A common stock outstanding during the period. Diluted earnings per share takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees. On September 4, 2013 (the grant date), the Company granted to its directors restricted shares of Class A common stock, which vest on the first anniversary of the grant date. In accordance with ASC 260, Earnings Per Share, awards of nonvested shares shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. For the three and nine months ended September 30, 2013, the directors restricted shares of Class A common stock were excluded from the diluted calculation as their inclusion would have been anti-dilutive as the Company was in a net loss position. The following is a calculation of the basic and diluted weighted-average number of shares of Class A common stock outstanding and EPS for the three and nine months ended September 30, 2013. Net income and the weighted-average number of shares of Class A common stock outstanding is based on the actual days in which the shares were outstanding for the period from July 29, 2013, the closing date of the Offering, to September 30, 2013.

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

(in thousands of dollars, except per share data)	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Income (numerator):		
Net income (loss) attributable to controlling interests	$ (821)	$ (821)
Weighted-average shares (denominator):		
Weighted-average number of shares of Class A common stock - basic and diluted	12,500	12,500
Earnings (loss) per share:		
Basic and diluted	$ (0.07)	$ (0.07)

9. Monarch Investment

On May 7, 2013, the Company entered into a marketing agreement with Monarch Natural Gas, LLC (Monarch), a company related through common ownership, for the sale to Monarch of natural gas produced from certain properties. In connection with that agreement, Monarch issued to the Company equity interests in its parent, Monarch Natural Gas Holdings, LLC, having an estimated fair value of $15.0 million. Contemporaneous with the execution of the marketing agreement and the issuance of the equity interests, the Company distributed 67% of the Monarch equity interests to the Company s owners pro rata based on equity contributions and approximately 16% of the interests to management. The remaining approximately 17% of the equity interests were reserved for distribution to management through an incentive plan. The Company recognized $0.1 million of compensation expense in the third quarter of 2013 in connection with the incentive plan. In addition, the Company recorded deferred revenue of $15.0 million which is being amortized on an estimated units-of-production basis commencing in September 2013, the first month of production sales to Monarch. The Company amortized $0.1 million of the deferred revenue balance during the three months ended September 30, 2013.

10. Commitments and Contingencies

The Company is subject to legal proceedings and claims that arise in the ordinary course of its business. The Company believes that the final disposition of such matters will not have a material adverse effect on its financial position, results of operations, or liquidity.

11. Income Taxes

Following the Offering, Jones began recording a federal income tax liability associated with its status as a corporation. The Company will recognize a tax liability on its share of pre-tax book income, exclusive of the non-controlling interest. JEH LLC is not subject to income tax at the federal level and only recognizes Texas margin tax. The following table summarizes the tax provision for the three and nine months ended

September 30, 2013 and 2012:

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Jones Energy, Inc.

Notes to Consolidated Financial Statements (Unaudited)

(in thousands of dollars)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Current tax expense				
Federal	$	$	$	$
State	15		48	
Total current expense	$ 15	$	$ 48	$
Deferred tax expense (benefit)				
Federal	(359)		(358)	
State		104	217	327
Total deferred expense (benefit)	$ (359)	$ 104	$ (141)	$ 327
Total tax expense (benefit)	$ (344)	$ 104	$ (93)	$ 327
Tax expense (benefit) attributable to controlling interests	(375)		(375)	
Tax expense attributable to non-controlling interests	31	104	282	327
Total tax expense (benefit)	$ (344)	$ 104	$ (93)	$ 327

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations section and audited consolidated financial statements and related notes thereto included in our final prospectus dated July 23, 2013 and filed on July 25, 2013 with the Securities and Exchange Commission pursuant to Rule 424(b) under the Securities Act and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report on Form 10-Q.

Overview

We are an independent oil and gas company engaged in the development, production and acquisition of oil and natural gas properties in the Anadarko and Arkoma basins of Texas and Oklahoma. Our CEO, Jonny Jones, founded our predecessor company in 1988 in continuation of his family s long history in the oil and gas business, which dates back to the 1920 s. We have grown rapidly by leveraging our focus on low cost drilling and completions and our horizontal drilling expertise to develop our inventory and execute several strategic acquisitions. We have accumulated extensive knowledge and experience in developing the Anadarko and Arkoma basins, having concentrated our operations in the Anadarko basin for 25 years and applied our knowledge to the Arkoma basin since 2011. We have drilled over 600 total wells, including over 420 horizontal wells, since our formation and delivered compelling economic returns over various commodity price cycles. Our operations are focused on horizontal drilling and completions within two distinct basins in the Texas Panhandle and Oklahoma:

- the Anadarko Basin targeting the liquids-rich Cleveland, Granite Wash, Tonkawa and Marmaton formations; and

- the Arkoma Basin targeting the liquids-rich fairway of the Woodford shale formation.

We optimize returns through a disciplined emphasis on controlling costs and promoting operational efficiencies, and we believe we are recognized as one of the lowest-cost drilling and completion operators in the Cleveland and Woodford shale formations.

The Anadarko and Arkoma basins are among the most prolific and largest onshore producing oil and natural gas basins in the United States, enjoying multiple producing horizons and extensive well control demonstrated over seven decades of development. The formations we target are generally characterized by oil and liquids-rich natural gas content, extensive production histories, long-lived reserves, high drilling success rates and attractive initial production rates. We focus on formations in our operating areas that we believe offer significant development and acquisition opportunities and to which we can apply our technical experience and operational excellence to increase proved reserves and production to deliver compelling economic rates of return. Our goal is to build value through a disciplined balance between developing our current inventory of 2,435 gross identified drilling locations and actively pursuing joint venture agreements, farm-out agreements, joint operating agreements and similar partnering agreements, which we refer to as joint development agreements, organic leasing proximate to existing acreage and strategic acquisitions.

Our profitability and ability to grow depend principally on the prices we obtain for our hydrocarbons, the volumes we produce and our ability to drill and complete wells at lower costs than other operators in our areas. Oil, natural gas and NGL prices historically have been volatile, may fluctuate widely in the future and are dependent on factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Development of unconventional oil and gas in the U.S. continues to change the landscape of the onshore resource as well as pricing for the commodities. In light of price volatility, we continually evaluate and adjust our drilling program to allocate capital to wells that we believe will provide the most attractive returns. Additionally, we hedge a substantial portion of our expected future oil and gas production to reduce our exposure to fluctuations in commodity price. See Quantitative and qualitative disclosures about market risk Commodity price risk and hedges below for discussion of our hedging and hedge positions.

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On July 29, 2013, we closed our initial public offering of 12,500,000 shares of our Class A common stock at a price to the public of $15.00 per share. We received net proceeds of approximately $177.0 million (net of underwriting discounts and commissions).

Third Quarter 2013 Highlights:

- Company-wide net production of 17,380 Boe/d, up 39% from the third quarter of 2012
- Produced over 18,500 Boe/d in September setting a new Company production record
- Cleveland net production of 10,624 Boe/d, up 100% from the third quarter of 2012
- EBITDAX of $52.5 million, up 78% from the third quarter of 2012
- Increased drilling pace from six to eight rigs and exited the quarter with seven rigs in the Cleveland and one rig in the Woodford; ten rigs running today
- Drilled first Woodford wells under new partnership with BP

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Results of Operations

The following table summarizes our revenues, expenses and production data for the periods indicated.

(in thousands of dollars except for production, sales price and average cost data)	Three Months Ended September 30, 2013	2012	Change	Nine Months Ended September 30, 2013	2012	Change
Revenues:						
Oil	$ 40,528	$ 14,013	$ 26,515	$ 104,777	$ 48,122	$ 56,655
Natural gas	13,437	7,726	5,711	41,124	20,130	20,994
NGLs	14,660	10,064	4,596	42,283	37,174	5,109
Total oil and gas	68,625	31,803	36,822	188,184	105,426	82,758
Other	226	132	94	673	660	13
Total operating revenues	68,851	31,935	36,916	188,857	106,086	82,771
Costs and expenses:						
Lease operating	7,761	5,776	1,985	19,308	17,107	2,201
Production taxes	3,469	1,192	2,277	9,103	3,951	5,152
Exploration	853	84	769	1,458	265	1,193
Depletion, depreciation and amortization	30,529	21,229	9,300	82,552	58,251	24,301
Impairment of oil and gas properties					61	(61)
Accretion of discount	170	146	24	434	427	7
General and administrative	13,974	3,832	10,142	25,611	11,508	14,103
Total costs and expenses	56,756	32,259	24,497	138,466	91,570	46,896
Operating income	12,095	(324)	12,419	50,391	14,516	35,875
Other income (expenses):						
Interest expense	(6,879)	(5,716)	(1,163)	(22,712)	(17,868)	(4,844)
Net gain (loss) on commodity derivatives	(20,728)	(18,436)	(2,292)	4,444	20,122	(15,678)
Gain (loss) on sales of assets	(55)	205	(260)	(30)	1,561	(1,591)
Total other income (expense)	(27,662)	(23,947)	(3,715)	(18,298)	3,815	(22,113)
Income before income tax	(15,567)	(24,271)	8,704	32,093	18,331	13,762
Income tax provision	(344)	104	(448)	(93)	327	(420)
Net income (loss) including non-controlling interests	(15,223)	(24,375)	9,152	32,186	18,004	14,182
Net income (loss) attributable to non-controlling interests	(14,402)		(14,402)	33,007		33,007
Net income (loss) attributable to controlling interests	$ (821)	$ (24,375)	$ 23,554	$ (821)	$ 18,004	$ (18,825)
Net production volumes:						
Oil (MBbls)	401	161	240	1,126	522	604
Natural gas (MMcf)	4,418	3,409	1,009	12,822	10,221	2,601
NGLs (MBbls)	462	420	42	1,287	1,265	22
Total (MBoe)	1,599	1,149	450	4,550	3,491	1,060
Average net (Boe/d)	17,380	12,489	4,891	16,667	12,741	3,926
Average sales price, unhedged:						
Oil (per Bbl), unhedged	$ 101.07	$ 87.04	$ 14.03	$ 93.05	$ 92.19	$ 0.86
Natural gas (per Mcf), unhedged	3.04	2.27	0.77	3.21	1.97	1.24
NGLs (per Bbl), unhedged	31.73	23.96	7.77	32.85	29.39	3.46
Combined (per Boe) realized, unhedged	42.92	27.68	15.24	41.36	30.20	11.16
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 89.40	$ 85.91	$ 3.49	$ 87.56	$ 88.33	$ (0.77)
Natural gas (per Mcf), hedged	3.87	3.82	0.05	3.99	3.81	0.18
NGLs (per Bbl), hedged	31.88	31.41	0.47	33.91	34.79	(0.88)
Combined (per Boe) realized, hedged	42.33	34.85	7.48	42.52	36.98	5.54
Average costs (per BOE):						
Lease operating	$ 4.85	$ 5.03	$ (0.18)	$ 4.24	$ 4.90	$ (0.66)

Production taxes	2.17	1.04	1.13	2.00	1.13	0.87
Depletion, depreciation and amortization	19.09	18.48	0.61	18.14	16.69	1.45
General and administrative	8.74	3.34	5.40	5.63	3.30	2.33

Non-GAAP financial measure

EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, exploration expense, net gains (losses) on commodity derivatives (excluding current period settlements of matured derivative contracts), and other items. EBITDAX is not a measure of net income as determined by GAAP.

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Management believes EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX has limitations as an analytical tool and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historical costs of depreciable assets. Our presentation of EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items and should not be viewed as a substitute for GAAP. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table sets forth a reconciliation of net income (loss) as determined in accordance with GAAP to EBITDAX for the periods indicated:

(in thousands of dollars)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Reconciliation of EBITDAX to net income				
Net income	$ (15,223)	$ (24,375)	$ 32,186	$ 18,004
Interest expense (excluding amortization of deferred financing costs)	6,204	4,831	20,709	15,218
Exploration expense	853	84	1,458	265
Income taxes	(344)	104	(93)	327
Amortization of deferred financing costs	675	885	2,003	2,650
Depreciation and depletion	30,529	21,229	82,552	58,251
Impairment of oil and natural gas properties				61
Accretion expense	170	146	434	427
Other non-cash charges	(83)	(80)	227	60
Stock compensation expense	9,906	142	10,379	425
Other non-cash compensation expense	127		2,592	
Net loss (gain) on commodity derivatives	20,728	18,436	(4,444)	(20,122)
Net loss (gain) on current period settlements of matured derivative contracts	(943)	8,245	5,262	23,665
Amortization of deferred revenue	(114)		(114)	
Loss (gain) on sales of assets	55	(205)	30	(1,561)
EBITDAX	$ 52,540	$ 29,442	$ 153,181	$ 97,670

Results of Operations - Three months ended September 30, 2013 as compared to three months ended September 30, 2012

Operating revenues

Oil and gas sales. Oil and gas sales increased by $36.8 million (115.7%) to $68.6 million for the three months ended September 30, 2013, as compared to $31.8 million for the three months ended September 30, 2012. The majority of the increase (65.8%) was due to higher crude oil production volumes with the remainder of the increase being attributable to higher natural gas production volumes combined with higher prices for all products. Average daily production increased 39.2% to 17,380 Boe per day for the three months ended September 30, 2013 as compared to 12,489 Boe per day for the three months ended September 30, 2012. Crude oil production increased 149.1% from 161 MBbls for the three months ended September 30, 2012 to 401 MBbls for the three months ended September 30, 2013, primarily resulting from the wells acquired from Chalker (the Chalker properties), which generally have an oil production rate that is higher than our average historical Cleveland wells, combined with subsequent drilling on our Cleveland acreage. Natural gas production increased 29.6% from 3,409 MMcf for the three months ended September 30, 2012 to 4,418 MMcf for the three months ended September 30, 2013, due to new wells added

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through drilling and the Chalker acquisition. The average realized oil price, excluding the effects of commodity derivative instruments, increased from $87.04 per Bbl to $101.07 per Bbl, or 16.1%, quarter over quarter. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $2.27 per Mcf to $3.04 per Mcf, or 33.9%. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, increased from $23.96 per Bbl to $31.73 per Bbl, or 32.4%.

Costs and expenses

Lease operating. Lease operating expense increased by $2.0 million (34.5%) to $7.8 million for the three months ended September 30, 2013, as compared to $5.8 million for the three months ended September 30, 2012. The increase occurred in correlation with the 39.2% increase in production volumes from 12,489 Boe per day for the three months ended September 30, 2012 to 17,380 Boe per day for the three months ended September 30, 2013. On a per unit basis, lease operating expense decreased by $0.18 per Boe or 3.6% for the three months ended September 30, 2013 as compared to the same period in 2012. As more Cleveland wells come on line, we are seeing particular types of operating expenses increase such as compressors and salt water disposal expenses. Although Chalker properties have an initial oil rate that is higher than our average historical Cleveland well and therefore generate higher revenue per well earlier in their life than average (and correspondingly lower lease operating expenses as a percentage thereof), we are seeing the increases in the above noted expenses.

Production taxes. Production taxes increased by $2.3 million (191.7%) to $3.5 million for the three months ended September 30, 2013 as compared to $1.2 million for the three months ended September 30, 2012. Overall production taxes increased in conjunction with the 115.7% increase in revenue; however, the average effective rate increased from 3.7% for the three months ended September 30, 2012 to 5.1% for the three months ended September 30, 2013. Production taxes were at a higher rate during the three months ended September 30, 2013 due to the acquisition and drilling of the Chalker properties in Texas, which imposes a higher initial tax rate than Oklahoma, where many of our other properties are located.

Exploration. Exploration expense increased from $0.1 million for the three months ended September 30, 2012 to $0.9 million for the three months ended September 30, 2013. The increase was attributable to seismic expenses incurred in the Arkoma.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $9.3 million (43.9%) to $30.5 million for the three months ended September 30, 2013 as compared to $21.2 million for the three months ended September 30, 2012. The increase was primarily the result of continued drilling activity and the addition of the Chalker properties at the end of 2012, which increased our total proved reserve base in the Cleveland formation. On a per unit basis, depletion expense increased $0.61 per Boe or 3.3% from $18.48 per Boe for the three months ended September 30, 2012 as compared to $19.09 per Boe for the three months ended September 30, 2013.

General and administrative. General and administrative expenses increased by $10.2 million (268.4%) to $14.0 million for the three months ended September 30, 2013, as compared to $3.8 million for the three months ended September 30, 2012. Of this increase, $9.9 million related to stock compensation expense, of which $9.6 million was expense related to the immediate vesting of certain shares on the Offering date. Excluding the stock compensation expense and other non-cash expenses of $0.1 million, general and administrative expense decreased, on a per unit basis, from $3.34 per Boe for the three months ended September 30, 2012 to $2.46 for the three months ended September 30, 2013. The increase in activity resulting from drilling and the acquisition of the Chalker properties significantly increased production (39.2% on a Boe basis) but did not cause a proportional increase in general and administrative expenses.

Interest and other. Interest and other financing expenses increased by $1.2 million (21.1%) to $6.9 million for the three months ended September 30, 2013, as compared to $5.7 million for the three months ended September 30, 2012. We increased our debt at the end of 2012 to fund the Chalker acquisition; however, a majority of this was paid down in July 2013 with the proceeds from the Offering. Our average debt outstanding for the three months ended September 30, 2013 was $490.6 million as compared to $424.3 million for the three months ended September 30, 2012.

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Gain (loss) on commodity derivatives. The net loss on commodity derivatives increased by $2.3 million (12.5%) to a loss of $20.7 million for the three months ended September 30, 2013, as compared to a loss of $18.4 million for the three months ended September 30, 2012. The higher loss was driven by higher current crude oil and natural gas prices as of September 30, 2013 ($106.24 and $3.57, respectively), as compared to the crude oil and natural gas prices as of September 30, 2012 ($94.56 and $2.63, respectively).

Results of Operations - Nine months ended September 30, 2013 as compared to nine months ended September 30, 2012

Operating revenues

Oil and gas sales. Oil and gas sales increased by $82.8 million (78.6%) to $188.2 million for the nine months ended September 30, 2013, as compared to $105.4 million for the nine months ended September 30, 2012. Over 60% of the increase was due to an increase in oil production volumes from the nine months ended September 30, 2012 to the nine months ended September 30, 2013 with the remainder of the increase being attributable to higher natural gas volumes and a higher average realized natural gas price. Crude oil production increased 115.7% from 522 MBbls for the nine months ended September 30, 2012 to 1,126 MBbls for the nine months ended September 30, 2013, primarily resulting from the Chalker properties, which generally have an oil production rate that is higher than our average historical Cleveland well. Natural gas production increased 25.4% from 10,221 MMcf for the nine months ended September 30, 2012 to 12,822 MMcf for the nine months ended September 30, 2013, due to new wells added through drilling and the Chalker acquisition. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $1.97 per Mcf to $3.21 per Mcf, or 62.9%.

Costs and expenses

Lease operating. Lease operating expense increased by $2.2 million (12.9%) to $19.3 million for the nine months ended September 30, 2013, as compared to $17.1 million for the nine months ended September 30, 2012. The increase occurred in correlation with the 30.8% increase in production volumes from 12,741 Boe per day for the nine months ended September 30, 2012 to 16,667 Boe per day for the nine months ended September 30, 2013. On a per unit basis, lease operating expense decreased by $0.66 per Boe or 13.4% for the nine months ended September 30, 2013 as compared to the same period in 2012. Non-recurring operating expenses accounted for $0.29 of the total per unit decrease as workover expenses were higher during the nine months ended September 30, 2012 as we performed more batch fracks, which require remedial work to get adjacent wells back on line. The remaining decrease in per unit operating expense is related to recurring operating expenses which were lower on a per unit basis as the Chalker wells generate higher revenue per well earlier in their life as they have a higher oil rate than our average historical Cleveland well.

Production taxes. Production taxes increased by $5.1 million (127.5%) to $9.1 million for the nine months ended September 30, 2013 as compared to $4.0 million for the nine months ended September 30, 2012. Overall production taxes increased in conjunction with the 78.6% increase in revenue; however, the average effective rate increased from 3.7% for the nine months ended September 30, 2012 to 4.8% for the nine months ended September 30, 2013. Production taxes accrued at a higher rate during the nine months ended September 30, 2013 due to the acquisition and drilling of the Chalker properties in Texas, which imposes a higher initial tax rate than Oklahoma, where many of our other properties are located.

Exploration. Exploration increased from $0.3 million for the nine months ended September 30, 2012 to $1.5 million for the nine months ended September 30, 2013. The increase was attributable to seismic expenses incurred in the Arkoma.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $24.3 million (41.7%) to $82.6 million for the nine months ended September 30, 2013 as compared to $58.3 million for the nine months ended September 30, 2012. The increase was primarily a result of continued drilling activity and the addition of the Chalker properties at the end of 2012, which increased our total proved reserve base in the Cleveland formation. On a per unit basis, depletion expense increased $1.45 per Boe or 8.7% from $16.69 per Boe for the nine months ended September 30, 2012 as compared to $18.14 per Boe for the nine months ended September 30, 2013.

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General and administrative. General and administrative expenses increased by $14.1 million (122.6%) to $25.6 million for the nine months ended September 30, 2013, as compared to $11.5 million for the nine months ended September 30, 2012. Of this increase, $10.4 million related to stock compensation expense, of which $9.6 million related to the immediate vesting of certain shares on the Offering date. An additional $2.6 million related to other non-cash compensation related to the Monarch incentive plan. Excluding the stock compensation expense and other non-cash expense, general and administrative expense decreased, on a per unit basis, from $3.30 per Boe for the nine months ended September 30, 2012 to $2.78 for the nine months ended September 30, 2013. The increase in activity resulting from drilling and the acquisition of the Chalker properties significantly increased production (30.8% on a Boe basis) but did not cause a proportional increase in general and administrative expenses.

Interest and other. Interest and other financing expenses increased by $4.8 million (26.8%) to $22.7 million for the nine months ended September 30, 2013, as compared to $17.9 million for the nine months ended September 30, 2012, primarily due to a $147.7 million increase in average debt outstanding. The increase in debt was used to finance the Chalker acquisition during the fourth quarter of 2012. In the third quarter of 2013, we paid down $167.0 million on the debt with the proceeds from the initial public offering.

Gain (loss) on commodity derivatives. The net gain on commodity derivatives decreased by $15.7 million to a gain of $4.4 million for the nine months ended September 30, 2013, as compared to a gain of $20.1 million for the nine months ended September 30, 2012. The decrease in the gain was attributable to increases in future crude oil prices. The 12-month forward prices at September 30, 2013 for crude oil averaged $97.82 per Bbl as compared to $93.22 per Bbl at December 31, 2012, while the 12-month forward prices at September 30, 2012 averaged $93.40 per Bbl as compared to $98.77 per Bbl at December 31, 2011.

Gain on sales of assets. The gain on sales of assets decreased from $1.6 million for the nine months ended September 30, 2012 to a loss of $0.03 million for the nine months ended September 30, 2013, due to the sale of properties in the North Barnett Shale during the first quarter of 2012 with no significant sales of properties in the first nine months of 2013.

Liquidity and Capital Resources

Our primary sources of liquidity have been borrowings under bank credit facilities and cash flows from operations. Our primary use of capital has been, and will continue to be during 2013 and for the foreseeable future, for the exploration, development and acquisition of oil and gas properties. The Company uses its borrowing capacity under the borrowing base on the Revolver to manage its working capital. Although working capital was negative at September 30, 2013, the Company had $222 million of available liquidity through its credit facility.

As we pursue reserves and production growth, we continually consider which capital resources, including cash flow, equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. We continually monitor market conditions and consider taking on additional debt, equity or other sources of financing. We strive to maintain financial flexibility in order to maintain substantial borrowing capacity under our senior secured revolving credit facility, facilitate drilling on our undeveloped acreage positions and permit us to selectively expand our acreage positions.

We believe that our cash on hand, cash flow from operating activities and availability under our credit facilities will be sufficient to fund our planned capital expenditures and operating expenses and comply with our debt covenants during the next 12 months. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

The following table summarizes our cash flows for the nine months ended September 30, 2013 and 2012:

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(in thousands of dollars)	Nine Months Ended September 30, 2013		2012	
Net cash provided by operating activities	$	118,565	$	63,473
Net cash used in investing activities		(119,609)		(65,692)
Net cash provided by financing activities		373		10,982
Net increase in cash	$	(671)	$	8,763

Cash flow provided by operating activities

Net cash provided by operating activities was $118.6 million during the nine months ended September 30, 2013 as compared to cash provided by operating activities of $63.5 million during the nine months ended September 30, 2012. The increase in operating cash flows was primarily due to a $82.8 million increase in revenues during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. The increase in revenue was primarily driven by a 115.7% increase in oil production volumes as a result of drilling and the Chalker acquisition in the fourth quarter of 2012, combined with an increase in both natural gas prices and volumes. The increase in cash flow was offset by a decrease in working capital resulting from an increase in drilling activity from four rigs running at September 30, 2012 to eight rigs running at September 30, 2013.

Cash flow used in investing activities

Net cash used in investing activities was $119.6 million during the nine months ended September 30, 2013 as compared to cash used in investing activities of $65.7 million during the nine months ended September 30, 2012. Capital expenditures increased $67.4 million during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012 due to an increase in drilling activity, particularly related to the Chalker properties. Cash flows from current period settlements of our commodity derivatives instruments decreased by $14.1 million during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012 as a result of an increase in crude oil and natural gas prices. Additionally, we received cash proceeds of $9.2 million from the sale of North Barnett properties in the first quarter of 2012 with no meaningful sales of properties occurring during the nine months ended September 30, 2013.

Cash flow used in or provided by financing activities

Net cash provided by financing activities was $0.4 million during the nine months ended September 30, 2013 as compared to net cash provided by financing activities of $11.0 million during the nine months ended September 30, 2012. The decrease in cash flows provided by financing activities was primarily due to net borrowings of $11.0 million during the nine months ended September 30, 2012. The proceeds from the sale of stock in the third quarter of 2013 were offset by repayment of debt of $172.0 million during the nine months ended September 30, 2013.

Contractual Obligations

There have been no material changes in our contractual obligations as reported in the Prospectus.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

There have been no changes to our critical accounting policies and estimates from those set forth in the Prospectus.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in the Prospectus, as well as with the unaudited consolidated financial statements and notes included in this Quarterly Report.

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into derivative instruments to manage or reduce market risk, but do not enter into derivative agreements for speculative purposes.

We do not designate these or future derivative instruments as hedges for accounting purposes. Accordingly, the changes in the fair value of these instruments are recognized currently in earnings.

Commodity price risk and hedges

Our principal market risk exposure is to oil, natural gas and NGL prices, which are inherently volatile. As such, future earnings are subject to change due to fluctuations in such prices. Realized prices are primarily driven by the prevailing prices for oil and regional spot prices for natural gas and NGLs. We have used, and expect to continue to use, oil, natural gas and NGL derivative contracts to reduce our risk of price fluctuations of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. The fair value of our oil, natural gas and NGL derivative contracts at September 30, 2013 was a net asset of $30.3 million.

As of September 30, 2013, we have hedged approximately 39.5% of our total forecasted production from proved reserves through 2017. The production hedged thereby is consistent with the anticipated monthly production levels in the December 31, 2012 reserve report. Actual production will vary from the amounts estimated in this reserve report, perhaps materially.

Counterparty and customer credit risk

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of these significant customers to meet their obligations or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

While we do not typically require our partners, customers and counterparties to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our partners or customers for oil and gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such parties as we deem appropriate under the circumstances. This evaluation may include reviewing a party s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, and undertaking the due diligence necessary to determine creditworthiness. The counterparties on our derivative instruments currently in place are lenders under the revolving credit facility with investment grade ratings. We are not permitted under the terms of the revolving credit facility to enter into derivative instruments with counterparties outside of the banks who are lenders under the revolving credit facility. As a result, any future derivative instruments will be with these or other lenders under the revolving credit facility who will also likely carry investment grade ratings.

Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness. The terms of the senior secured revolving credit facility and the second lien term loan provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 0.75% to 2.75% on the revolver and 6.0-7.0% on the term loan depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. During the three months ended September 30, 2013, borrowings under the senior secured revolving credit facility and second lien term loan bore interest at a weighted-average rate of 2.74% and 9.15%, respectively. During the nine months ended September 30, 2013, borrowings under the senior secured revolving credit facility and second lien term loan bore interest at a weighted average rate of 3.04% and 9.21%, respectively.

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Item 4. Controls and Procedures

Changes in Internal Control over Financial Reporting

Prior to the completion of our initial public offering, we were a private company with limited accounting personnel to adequately execute our accounting processes and limited other supervisory resources with which to address our internal control over financial reporting. As previously discussed in our Prospectus, we have not maintained an effective control environment in that the design and execution of our controls has not consistently resulted in effective review of our financial statements and supervision by appropriate individuals. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare our financial statements. We concluded that these control deficiencies, although varying in severity, constitute a material weakness in our control environment.

Management has taken steps to address the causes of our audit adjustments and to improve our internal control over financial reporting, including the implementation of new accounting processes and control procedures and the identification of gaps in our skills base and expertise of the staff required to meet the financial reporting requirements of a public company. Since July 2010, we have hired three accounting managers along with a number of degreed staff accountants. This team has enabled us to expedite our month-end close process, thereby facilitating the timely preparation of financial reports. Likewise, we strengthened our internal control environment through the addition of skilled accounting personnel. We continue to hire incremental qualified staff as needed in conjunction with a comprehensive review of our internal controls and formalization of our review and approval processes. We designed new processes and implemented controls to remediate the material weakness identified as of December 31, 2012. However, insufficient time has elapsed to test the operational effectiveness of these new controls, and as such, we are unable to conclude the material weakness has been remediated.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. In light of the previously identified material weakness described above and the insufficient time to test the operational effectiveness of our new processes and controls, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective at the reasonable assurance level as of September 30, 2013.

Management s Assessment of Internal Control over Financial Reporting

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company s internal control over financial reporting in its annual report. Pursuant to the recently enacted Jumpstart Our Business Startups Act of 2012 (the JOBS Act), our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an emerging growth company as defined in the JOBS Act. Our first Annual Report on Form 10-K will not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by SEC rules applicable to newly public companies. Our management will be required to provide an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 10 to the Consolidated Financial Statements appearing in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated in this item by reference.

Item 1A. Risk Factors

Our business faces many risks. Any of the risk discussed elsewhere in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

Except for the risk factor noted below, there have been no material changes in our risk factors from those described in our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013. For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our Quarterly Report on Form 10-Q for the period ended June 30, 2013.

If we do not fulfill our obligation to drill minimum numbers of wells specified in our joint development agreements, we will lose the right to develop the undeveloped acreage associated with the agreement and any proved undeveloped reserves attributable to such undeveloped acreage.

If we do not meet our obligation to drill the minimum number of wells specified in a joint development agreement, we will lose the right to continue to develop the undeveloped acreage covered by the agreement, which would result in the loss of any proved undeveloped reserves attributable to such undeveloped acreage. For example, pursuant to the terms of our joint development agreement with Southridge Energy, LLC, or Southridge, we were obligated to drill 20 additional wells prior to October 31, 2013 in order to continue to earn an interest in future wells and acreage. We elected not to drill any wells under this agreement in 2013, and as a result did not meet the drilling requirement. We were unable to reach a mutually acceptable extension agreement with Southridge; however, we have made a proposal to acquire all of Southridge s interest in the property covered by the Southridge joint development agreement, which proposal is currently being evaluated by Southridge. If the current efforts to acquire the Southridge property are unsuccessful, we will no longer have the right to develop approximately 11,517 gross (3,310 net) acres in the Woodford shale formation, and will reduce by approximately 15.5 MMBoe our proved undeveloped reserves attributable to such acreage (representing approximately 18% of our proved reserves and approximately 7% of our standardized measure as of December 31, 2012) that were included in our estimated proved reserves as of December 31, 2012. We estimate that we would incur an impairment charge of approximately $15 million in connection with such a reduction in our proved reserves.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference herein to Exhibit 3.1 of the Form 8-K, filed by the registrant on July 30, 2013).
3.2	Amended and Restated Bylaws (incorporated by reference herein to Exhibit 3.2 of the Form 8-K, filed by the registrant on July 30, 2013).
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Jonny Jones (Principal Executive Officer).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Robert J. Brooks (Principal Financial Officer).
32.1**	Section 1350 Certification of Jonny Jones (Principal Executive Officer).
32.2**	Section 1350 Certification of Robert J. Brooks (Principal Financial Officer).
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* - filed herewith

** - furnished herewith

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SIGNATURES

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

Jones Energy, Inc.

(registrant)

Date: November 8, 2013	By:	/s/ Jonny Jones	
		Name:	Jonny Jones
		Title:	*Chief Executive Officer*

Signature Page to Form 10-Q