expertise CREATES opportunities

JONES ENERGY 2014 ANNUAL REPORT

ABOUT JONES ENERGY

Jones Energy, Inc. (NYSE: JONE) is an Austin, Texas–based 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. We have grown rapidly by leveraging our horizontal drilling expertise and low cost operations to develop our inventory.

OPERATIONS OVERVIEW

ANADARKO BASIN

KEY FORMATION:
Cleveland

GROSS DRILLING LOCATIONS:
1,594

NET DRILLING LOCATIONS:
1,001

LEASED ACRES:
162,580

DAILY PRODUCTION:
17.0 MBoe/d

ARKOMA BASIN

KEY FORMATION:
Woodford

GROSS DRILLING LOCATIONS:
777

NET DRILLING LOCATIONS:
85

LEASED ACRES:
17,292

DAILY PRODUCTION:
4.0 MBoe/d

TOTAL PROVED RESERVES

115.3

MMBOE

DAILY PRODUCTION

23,216

BOE/D

GROSS ACREAGE

218,015

GROSS DRILLING LOCATIONS

2,765

DEAR *fellow* SHAREHOLDERS:

A lot has changed in the oil and gas industry since I wrote to you this time last year. As always, the future is uncertain and no one has a crystal ball. But this I know to be true: Experience is an irreplaceable asset, especially in turbulent times. After all, experience is necessary to develop expertise, and *expertise creates opportunities*.

This time last year, Jones Energy was still a newly public company. But we were not new to oil and gas. I founded Jones Energy as a private E&P company 26 years ago in continuation of my family's long tradition in the oil and gas business.

LETTER FROM JONNY JONES
Founder, Chairman, & CEO

I know what you're thinking: "So what? Yes, you have experience, but what does that really mean for me today?"

It means that we have been here before. We are ready for this. We understand that volatile commodity prices are an inevitable reality in the oil and gas business. In fact, some of the greatest opportunities we have seen as a company have been born out of an industry downturn.

When there is uncertainty and a lack of predictability, maintaining flexibility is key. We have made it a point to be flexible, both from an operational and a financial perspective.

We do not have long-term contracts with our rig providers or other vendors. This allowed us to drop from 11 active rigs in the fall of 2014 to just 3 active rigs by the end of January 2015. We also have the ability to add rigs as drilling and completion costs come down even further and margins improve. Although it may sound counterintuitive, being the low-cost operator means that our costs are the first to drop. Being best-in-class where we operate gives us leverage when negotiating with our partners and vendors — they know the lowest cost operator will also be one of the first ones back in the game as soon as margins return.

Our extensive hedge program provides us with significant financial flexibility, helping to secure our cash flow amidst an uncertain commodity price environment. We have hedged 85% of our estimated oil and gas production through 2016 at approximately $85 per barrel and $4.50 per Mcf. A large portion of our estimated 2015 natural gas liquids production is hedged as well. Our hedge position gives us margin visibility. It allows us to focus on executing our 2015 operating plan, instead of trying to react to commodity prices.

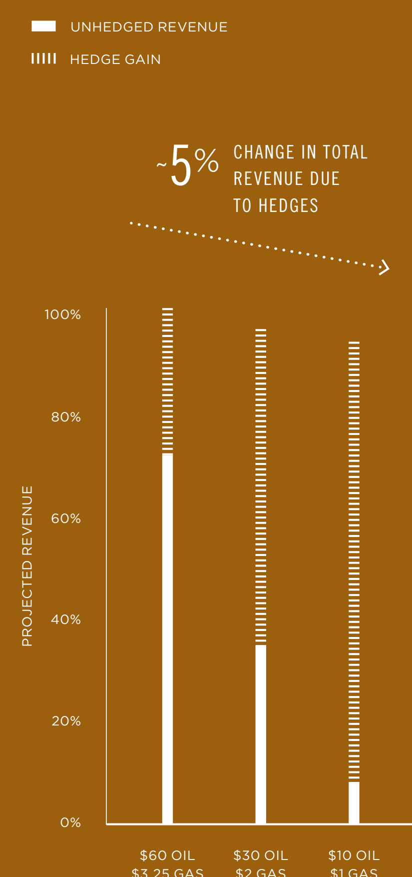
Hedging has been a foundation of Jones Energy since I started the company 26 years ago. We believe that if a well is good enough to drill, it is prudent to lock in the return with hedges. We will continue to hedge, even if at lower commodity price levels. The key to an effective hedging program is putting hedges in place, dutifully and methodically, regardless of our view on the outlook for commodity prices. We continue to believe that taking price risk off the table, even in a lower price environment, is the right way to run our business.

In addition, earlier this year, we raised approximately $375 million in gross proceeds through three transactions: a private placement of $250 million in senior notes, a registered direct offering of $50 million of common stock, and a $77 million public offering of common stock. These transactions significantly enhanced our liquidity and solidified

HEDGED *for* SUCCESS

Jones has a strong hedge position that mitigates the risk of continued commodity price declines. In the chart below, you can observe how even if oil prices decline to $10 per barrel and gas prices to $1 per Mcf, our projected 2015 revenue only declines by approximately 5%.

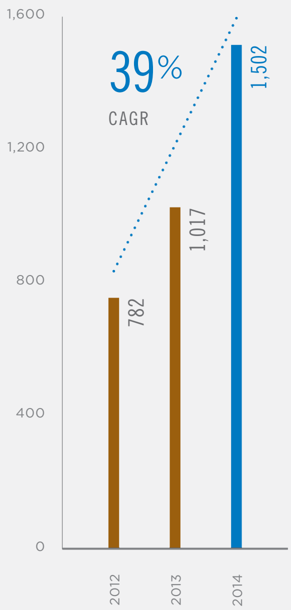
HEDGING IMPACT ON PROJECTED 2015 REVENUE



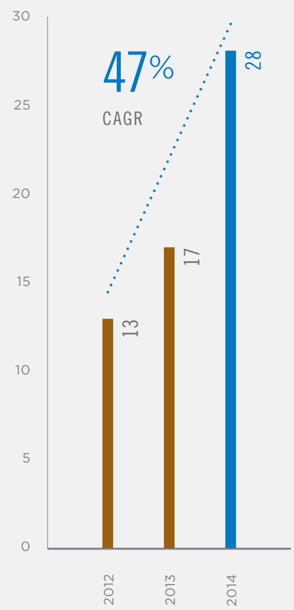
VALUE creation

We will do our best to make decisions that maximize value for our shareholders — well beyond the current commodity environment — while staying true to our values and tradition.

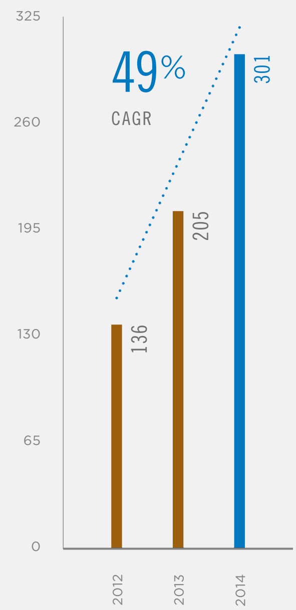
PV-10 OF PROVED RESERVES
($ IN MILLIONS)



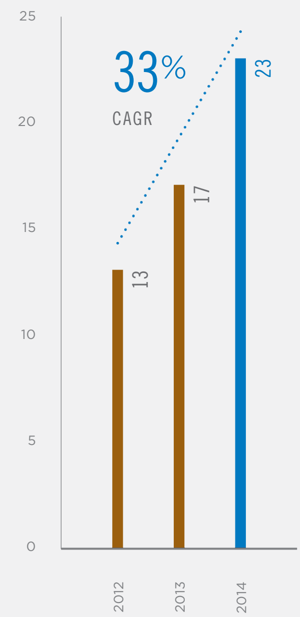
PROVED OIL RESERVES
(MMBOE)



EBITDAX
($ IN MILLIONS)



AVERAGE DAILY PRODUCTION
(MBOE/D)



our balance sheet. From our past experience, we know this to be true — organizations with the liquidity to capitalize on opportunities have a significant competitive advantage. With our recent capital raises, we believe the company is in a solid position financially, which allows us to be opportunistic.

Overall, 2014 was a year of many accomplishments for Jones Energy. We made some big strides — actions that I believe will benefit us in 2015 and beyond. Please allow me to review our key accomplishments.

SIGNIFICANT VALUE CREATION

2014 was a year of significant growth in proved reserves, production and EBITDAX. This was a direct result of our active drilling program, a very successful leasing program, and the oil uplift achieved with increased frack density in our core Cleveland play. In 2014, we grew the PV-10 value of our proved reserves by 48%, driven by a 30% increase in total proved reserves and a 65% increase in proved oil reserves. We also grew EBITDAX by 47% and production by 35% — impressive growth by any standard.

OIL UPLIFT — A TRUE PARADIGM SHIFT IN A MATURE PLAY

When we began drilling horizontal wells in the Cleveland in 2004, we believed that the Cleveland was a natural gas play. Today, we know the Cleveland is an oil play.

What changed?

Bolstered by our experience from drilling over 400 Cleveland horizontal wells and by major improvements in completion technology, we have found the primary driver of oil production in the Cleveland to be the number of frack stages. Or to put it simply, for a Cleveland well, more frack stages equates to more oil production.

Our ability to employ an increased number of frack stages has resulted in a greater than 30% increase in oil production from our Cleveland wells. This oil uplift has resulted in a meaningful increase in value in our Cleveland play.

ORGANIC INVENTORY GROWTH THROUGH LEASING

Last year, we added more than 21,000 net acres to our portfolio through leasing. This allowed us to replace all of the Cleveland locations we drilled in 2014. It also provides us with additional opportunities to drill in formations both above and below the Cleveland in the future. All of this was acquired at a price of approximately $1,300 per net acre, which is well below the lease prices being paid by many of our competitors in other regions.

> In 2015, we will execute our operating plan, focusing on our core competencies. Below, I outline our key directives for 2015.

STICKING TO OUR BREAD AND BUTTER

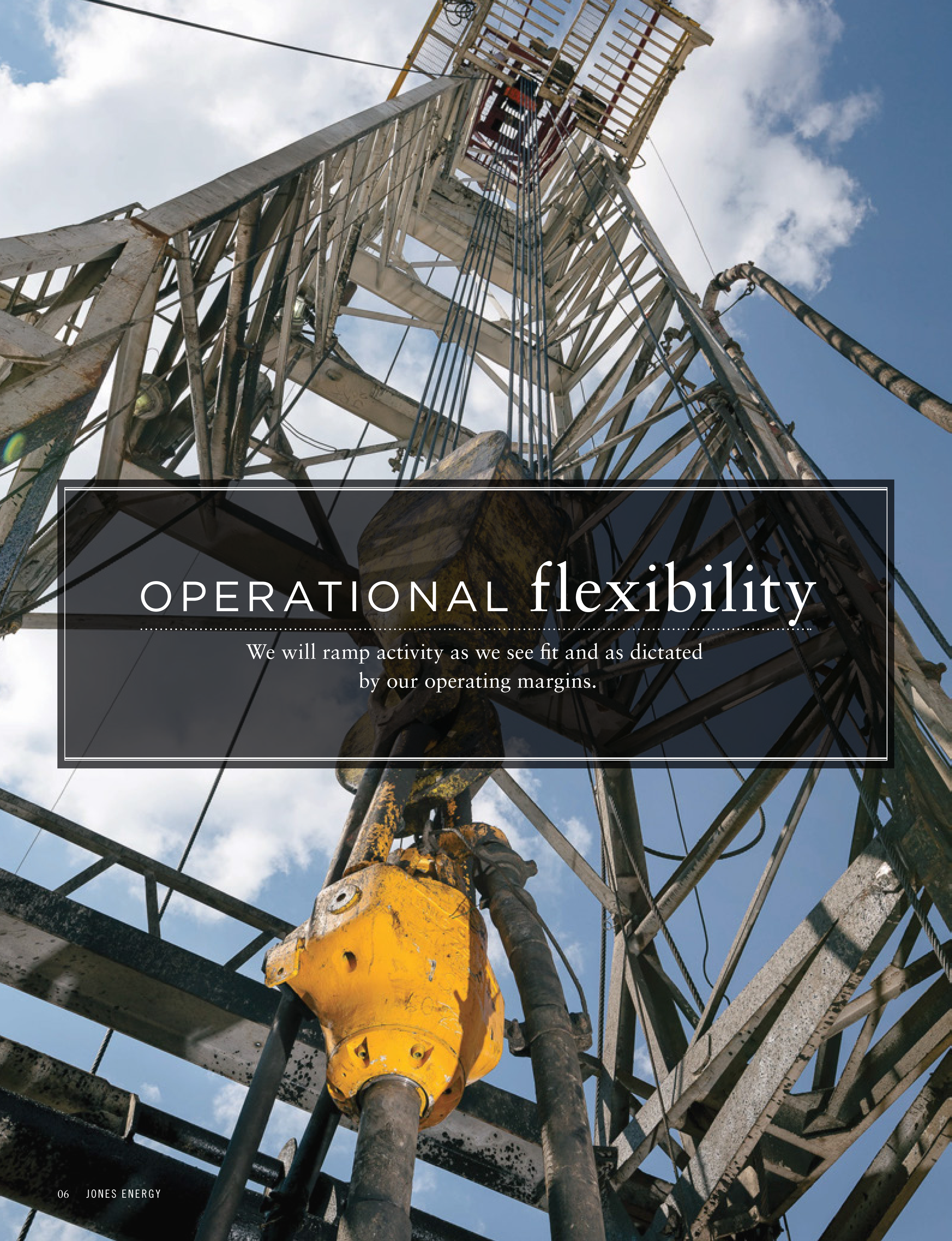
We will use all that we have learned from over 25 years of experience in the Anadarko Basin, and apply it to what we do best — drilling Cleveland wells. We plan to allocate the majority of our capital in 2015 to drilling Cleveland wells, utilizing a tried and true, open-hole completion method. We have completed hundreds of Cleveland wells using the open-hole completion technology, and believe this completion technique will allow us to achieve the optimal number of frack stages at the lowest possible cost. We continue to see significant opportunity within our footprint in the Anadarko Basin beyond just the Cleveland play, but believe the prudent choice in the current commodity environment is to focus on our core competency — being a best-in-class operator in the Cleveland.

MAINTAINING OPERATIONAL FLEXIBILITY

We will ramp rig activity up or down as we see fit and as dictated by our operating margins. We will not grow simply for growth's sake, but will only allocate capital to projects when and if we believe it is prudent and profitable to do so.

MAXIMIZING RETURNS THROUGH COST MANAGEMENT

We will continue to focus relentlessly on maintaining our low cost operations, which is paramount to achieving a competitive advantage in our industry. We have already seen a material reduction in operating costs since December 2014, and we will continue to work with our partners and vendors to achieve additional cost improvements.



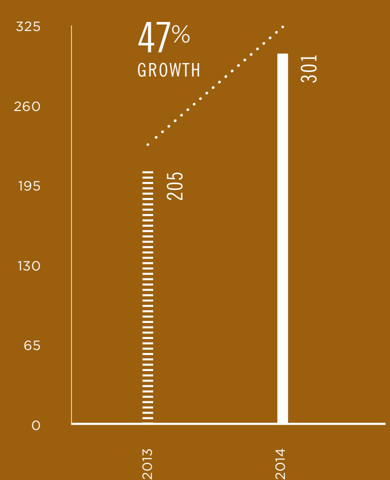
OPERATIONAL flexibility

We will ramp activity as we see fit and as dictated by our operating margins.

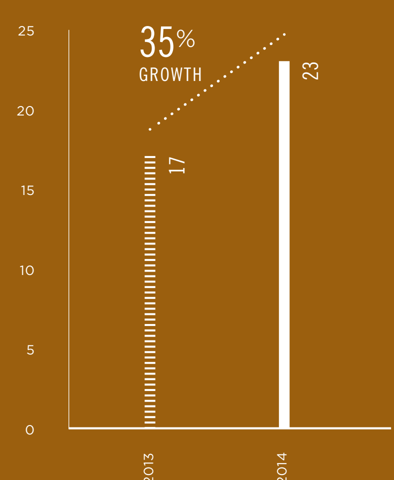
IMPRESSIVE GROWTH *by* ANY STANDARD

In 2014, we grew the PV-10 value of our proved reserves by 48%, driven by a 30% increase in total proved reserves and a 65% increase in proved oil reserves. We also grew EBITDAX by 47% and production by 35%.

EBITDAX
($ IN MILLIONS)



AVERAGE DAILY PRODUCTION
(MBOE/D)



PREPARING FOR MARKET OPPORTUNITIES

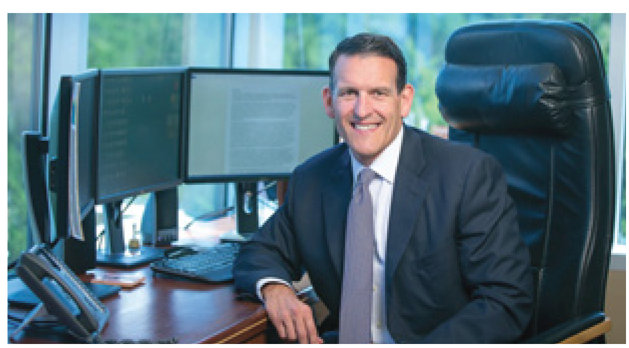
I have always said that success is achieved when hard work meets opportunity. We cannot predict what opportunities may come our way in 2015, but we will do our best to be ready for any opportunity, whether it involves acquisitions, joint ventures, or organic growth. Focusing on costs, exercising patience, and allocating capital in a purposeful and deliberate way will drive our success in 2015.

In closing, I would like to thank you for your continued support and belief in Jones Energy. We are off to a great start in 2015, and I believe we are in excellent position to execute on our operating plan.

Having been in the business for 26 years, we know by now that commodity prices go up and down — after all, the oil and gas industry is cyclical. But at Jones Energy, we also know that we must focus on what we can control. We must do our best to make decisions that maximize value for our shareholders — well beyond the current commodity environment — while staying true to our values and tradition.

Yours truly,

JONNY JONES
Founder, Chairman, & CEO
Jones Energy



JONES ENERGY, INC.

Consolidated Statements of Operations

(In thousands of dollars)	YEAR ENDED DECEMBER 31, 2014	2013	2012
OPERATING REVENUES			
Oil and gas sales	$ 378,401	$ 258,063	$ 148,967
Other revenues	2,196	1,106	847
Total operating revenues	380,597	259,169	149,814
OPERATING COSTS AND EXPENSES			
Lease operating	43,843	27,781	23,097
Production taxes	18,094	12,865	5,583
Exploration	3,453	1,710	356
Depletion, depreciation and amortization	181,669	114,136	80,709
Impairment of oil and gas properties	-	14,415	18,821
Accretion of discount	770	608	533
General and administrative (including non-cash compensation expense)	25,763	31,902	15,875
Total operating expenses	273,592	203,417	144,974
Operating income	107,005	55,752	4,840
OTHER INCOME (EXPENSE)			
Interest expense	(46,726)	(30,774)	(25,292)
Net gain (loss) on commodity derivatives	189,641	(2,566)	16,684
Gain (loss) on sales of assets	297	(78)	1,162
Other income (expense), net	143,212	(33,418)	(7,446)
Income (loss) before income tax	250,217	22,334	(2,606)
INCOME TAX PROVISION (BENEFIT)	26,074	(71)	473
Net income (loss)	224,143	22,405	(3,079)
Net income attributable to non-controlling interests	183,275	24,591	-
Net income (loss) attributable to controlling interests	$ 40,868	$ (2,186)	$ (3,079)
Adjusted net income [1]	$ 64,205	$ 54,792	$ 29,411
EBITDAX [2]	$ 301,393	$ 204,997	$ 135,741
Production (MMBoe)	8.5	6.2	4.9
Proved reserves (MMBoe)	115.3	89.0	85.3

[1] Adjusted net income is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements. We define adjusted net income as net income excluding the impact of certain non-cash items, including gains or losses on commodity derivative instruments not yet settled, impairment of oil and gas properties, non-cash compensation expense, and the gain on bargain purchase associated with the Southridge acquisition in 2011. For a reconciliation of adjusted net income to our net income, see Item 6. "Selected Financial Data –Non-GAAP financial measures" in our attached Form 10-K.

[2] EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of the Company's consolidated financial statements. We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, exploration expense, gains and losses from derivatives less the current period settlements of matured derivative contracts, and other items. For a reconciliation of EBITDAX to our net income, see Item 6. "Selected Financial Data –Non-GAAP financial measures" in our attached Form 10-K.

form 10-K

JONES ENERGY

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

FORM 10-K

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

For the fiscal year ended: December 31, 2014

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

For the transition period from to

Commission file number: 001-36006

Jones Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**80-0907968**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
(Address of principal executive offices) (Zip Code)

Tel: (512) 328-2953
Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Exchange Act:

Title of class	Name of each exchange on which registered
Class A Common Stock, $0.001 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☒

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 ☒ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 ☒	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	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 ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2014 (the last business day of the Registrant's most recently completed second fiscal quarter) based on the closing price of the Class A common stock on the New York Stock Exchange was $256 million.

There were 25,208,402 and 36,422,660 shares of the registrant's Class A and Class B common stock, respectively, outstanding on February 27, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2015 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year, which we refer to as the Proxy Statement, are incorporated by reference into Part III of this Annual Report on Form 10-K.

JONES ENERGY, INC.
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Cautionary Statement Regarding Forward-Looking Statements

The information in this Annual Report on Form 10-K (the "Annual Report"), includes "forward-looking statements." All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "should," "will," "may," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Risk Factors" included in this report. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events, actions and developments including:

- business strategy;
- estimated current and future net reserves and the present value thereof;
- drilling and completion of wells including our identified drilling locations;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- the timing, extent and duration of changes in, and level of volatility of, prices for oil, natural gas and NGLs;
- customers' elections to reject ethane and include it as part of the natural gas stream;
- timing and amount of future production of oil and natural gas;
- availability and cost of drilling, completion and production equipment;
- availability and cost of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- ability to fund our 2015 capital expenditure budget;
- availability and terms of capital;
- development results from our identified drilling locations;
- ability to generate returns and pursue opportunities;
- marketing of oil, natural gas and NGLs;
- property acquisitions and dispositions;
- the availability, cost and terms of, and competition for mineral leases and other permits and rights-of-way and our ability to maintain mineral leases;
- costs of developing our properties and conducting other operations;
- general economic conditions, including the levels of supply and demand for oil, natural gas and NGLs, and the commodity price environment;
- competitive conditions in our industry;
- effectiveness and extent of our risk management activities;

- estimates of future potential impairments;
- environmental and endangered species regulations and liabilities;
- counterparty credit risk;
- the extent and effect of any hedging activities engaged in by us;
- the impact of, and changes in, governmental regulation of the oil and natural gas industry, including tax laws and regulations, environmental, health and safety laws and regulations, and laws and regulations with respect to derivatives and hedging activities;
- developments in oil-producing and natural gas-producing countries;
- uncertainty regarding our future operating results;
- weather, including its impact on oil and natural gas demand and weather-related delays on operations;
- technology; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil and natural gas. These risks include, but are not limited to, commodity price levels and volatility, inflation, the cost of oil field equipment and services, lack of availability of drilling, completion and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under "Risk Factors" in this report.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this report.

References

Unless indicated otherwise in this Annual Report or the context requires otherwise, all references to "Jones Energy," the "Company," "our company," "we," "our" and "us" refer to Jones Energy, Inc. and its subsidiaries, including Jones Energy Holdings, LLC ("JEH"). Jones Energy, Inc. is a holding company whose sole material asset is an equity interest in JEH.

PART 1

Item 1. Business

Organization

Jones Energy, Inc. was incorporated pursuant to the laws of the State of Delaware in March 2013 to become a holding company for an investment in Jones Energy Holdings, LLC ("JEH"). As the sole managing member of JEH, Jones Energy, Inc. is responsible for all operational, management and administrative decisions relating to JEH's business and consolidates the financial results of JEH and its subsidiaries.

Jones Energy, Inc.'s certificate of incorporation authorizes two classes of common stock, Class A common stock and Class B common stock. The Class B common stock is held by the pre-IPO owners of JEH and can be exchanged (together with a corresponding number of JEH 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. Jones Energy, Inc.'s Class A common stock has been listed on the New York Stock Exchange ("NYSE") under the symbol "JONE" since July 2013.

Overview

We are an independent oil and gas company engaged in the exploration, development, production and acquisition of oil and natural gas properties in the Anadarko and Arkoma basins of Texas and Oklahoma. Our Chairman and 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 our Anadarko and Arkoma basin assets, having concentrated our operations in the Anadarko basin for over 25 years and applied our knowledge to the Arkoma basin since 2011. We have drilled over 775 total wells, including over 590 horizontal wells, since our formation and delivered compelling rates of return 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 primarily the liquids-rich Cleveland, with additional opportunities in other prospective formations, including the Tonkawa, Marmaton and Granite Wash; and
- the Arkoma Basin—targeting the Woodford shale formation.

We seek to 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 our targeted formations.

The Anadarko and Arkoma basins are among the most prolific and largest onshore producing oil and natural gas basins in the United States, characterized by multiple producing horizons and extensive well control collected over 100 years of development. We leverage our extensive geologic experience in the basins and seek to identify the most profitable exploration and development opportunities to apply our operational expertise. The formations we target are generally characterized by oil and/or 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 attractive economic rates of return. Our goal is to build value through a disciplined balance between developing our current inventory of 2,765 gross identified drilling locations, identifying new opportunities within our existing asset base, and actively pursuing organic leasing, strategic acquisitions and joint development agreements. In all of our joint development agreements, we control the drilling and completion of a well, which is the phase during which we can most effectively leverage our operational expertise and cost discipline. Following completion, we may in some cases turn over operatorship to a partner during the production phase of a well. We believe the ceding to us of drilling and completion operatorship in our areas of operation by several large oil and gas companies, including ExxonMobil and BP, reflects their acknowledgement of our low-cost, safe and efficient operations.

As of December 31, 2014, our total estimated proved reserves were 115.3 MMBoe, of which 52% were classified as proved developed reserves. Approximately 24% of our total estimated proved reserves as of December 31, 2014 consisted of oil, 34% consisted of NGLs, and 42% consisted of natural gas. As of December 31, 2014, our properties included 947 gross producing wells. For the three years ended December 31, 2014, we drilled 279 wells, substantially all of which we drilled as operator. The following table presents summary reserve, acreage and production data for each of our core operating areas:

	As of December 31, 2014				Year Ended December 31, 2014	
	Estimated Net Proved Reserves		Acreage		Average Daily Net Production	
	MMBoe	% Oil and NGLs	Gross Acreage	Net Acreage	MBoe/d	% Oil and NGLs
Cleveland	83.0	64%	162,580	109,260	17.0	66%
Woodford	25.4	43%	17,292	5,227	4.0	33%
Other	6.9	39%	38,143	17,015	2.2	27%
All properties	115.3	58%	218,015	131,502	23.2	57%

The following table presents summary well and drilling location data for each of our key formations for the date indicated:

	As of December 31, 2014			
	Producing Wells		Identified Drilling Locations(1)	
	Gross	Net	Gross	Net
Cleveland	502	357	704	477
Woodford(2)	148	59	777	85
Other	297	95	1,284	553
All properties	947	511	2,765	1,115

(1) Our total identified drilling locations include 518 gross locations associated with proved undeveloped reserves as of December 31, 2014. We have estimated our drilling locations based on well spacing assumptions for the areas in which we operate and other criteria. See "Business—Development of Proved Undeveloped Reserves" and "Business—Drilling Locations" for more information regarding our proved undeveloped reserves and the processes and criteria through which these drilling locations were identified.

(2) Of the 777 gross (85 net) drilling locations in the Woodford formation, 351 gross (24 net) locations are available through our agreement with Vanguard Natural Resources. As of December 31, 2014, we have drilled five of the eight wells required to earn the acreage available under the Vanguard agreement. Drilling the three remaining wells will allow us to continue development and earn additional locations under the Vanguard agreement, which is otherwise subject to expiration in the event such drilling has not begun by April 2016.

Our 2014 capital expenditures totaled $524 million, of which $468 million was utilized to drill and complete wells. We currently plan to invest approximately $210 million in total capital expenditures in 2015, including approximately $190 million for drilling and completion, and $20 million for workovers and efficiency projects. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Assuming current market conditions and drilling success rates comparable to our historical performance, we believe we will be able to fund all of our 2015 budgeted capital expenditures with our cash flow from operations and projected availability under our credit facilities.

Our 2015 capital budget assumes a three rig program in the Cleveland during the first quarter, and, assuming additional drilling and completion cost reductions can be achieved, two additional rigs being added during the second quarter, resulting in a five rig program in the Cleveland in the second half of 2015. We have allocated our 2015 capital expenditure budget as follows:

	2015 Capital Expenditure Budget
	(in millions)
Drilling and completion:	
Cleveland	$190
Other activities	20
All properties and activities	$210

Although we reduced our year end 2014 rig count in early 2015, we believe a reasonable rig schedule will allow us to develop all drilling locations classified as proved undeveloped reserves in the year-end reserve report within five years.

Business Strategies

Our goal is to increase shareholder value by managing our capital expenditures and level of activity to maximize well level returns in the current commodity environment while also evaluating and executing opportunities for growth of reserves, production, and cash flow through potential partnerships, acquisitions, and leasing opportunities. We seek to achieve this goal by executing the following strategies:

Develop Our Multi-Year Inventory.

We intend to add production and reserves through the development of our existing drilling inventory, which we believe to be repeatable and low-risk. The Company has a long history in the Midcontinent, having drilled over 775 wells in the area since 1988. We believe our historical drilling experience, together with the results of substantial industry activity within our operating areas, reduces the risk and uncertainty associated with drilling horizontal wells in these areas. As of December 31, 2014, we have identified 2,765 gross drilling locations, which gives us many years of development drilling. We expect 100% of our development capital expenditures in 2015 to be dedicated to horizontal drilling.

Maintain the Lowest Cost Structure in the Plays Where We Operate.

Decades of experience in the Midcontinent and emphasis on operational execution and cost control have allowed us to drill and complete wells at significantly lower cost than most other operators and, as a result, to realize compelling economic returns. In the Cleveland, for example, from 2005 to 2013 we reduced our well spud-to-release time, which directly affects drilling costs, from 30 days to 26 days, and in 2014 we further reduced that metric to 23 days. During that same timeframe, we have more than doubled our lateral lengths, which directly affects production, from approximately 2,000 feet to approximately 4,500 feet per well. We will continue to apply this expertise while also leveraging our leading position in our focus areas to obtain the best possible pricing from service providers which we expect will further reduce capital costs and ultimately enhance returns. Our cost structure is particularly important in periods of low commodity prices and gives us an advantage over other operators as we compete for acquisitions and strategic partnerships.

Opportunistically Grow Through Exploration, Acquisitions and Strategic Partnerships.

As a complement to our development program, we look to execute acquisitions, leases and partnerships where our operating experience can be leveraged. Given the Company's ability to decrease costs and ramp up drilling activity, we seek opportunities that have less PDP reserves and a large number of high-quality drilling locations. Since 2009, we have successfully executed four significant acquisitions and several bolt-on acquisitions in our operating areas, for an aggregate purchase price of approximately $900 million.

We also continue to seek new leasing opportunities to expand our acreage position and complement our existing drilling inventory, as we believe that targeted organic leasing around our existing acreage provides the ability for greater returns due to cost and operating synergies in overlapping areas of operation. In calendar year 2014, we leased approximately 21,000 net acres.

Joint development opportunities complement our acquisition strategy by providing a capital efficient and risk-lowering approach to acquiring drilling opportunities. These agreements give us control over the drilling and completion phase of the well, where we can add value by applying our low cost structure. In this regard, we have a history of developed relationships with several large exploration and production companies such as BP, ConocoPhillips, Devon Energy, ExxonMobil, Linn Energy, Vanguard Natural Resources and Samson, in which they have farmed out portions of their basin operations to us. We have drilled over 300 wells in connection with these types of agreements, over 165 of which have been drilled in connection with an active 14-year farm-out and development agreement with ExxonMobil.

Exploit Upside Within Our Existing Assets.

We plan to continue exploiting our proved reserves to maximize production through optimized drilling and completion techniques. Furthermore, the stacked reservoirs within our asset base provide exposure to additional upside potential in several emerging resource plays. We have begun assessing the potential of both the Tonkawa and Marmaton formations in the Anadarko Basin. We expect to engage in additional development activity within these plays as commodity prices improve. Based upon our recent assessment, we believe that we have approximately 890 potential drilling locations in the Tonkawa and Marmaton formations that provide us with additional resource potential. We began testing the potential of the Tonkawa formation by drilling six wells on our acreage in 2014 and are monitoring the production of those wells at this time. Further, our current leasehold position provides longer term potential exposure to other prospective formations found in the Anadarko basin, including the Douglas, Cottage Grove, Cherokee Shale, Atoka Shale, and the Upper, Middle and Lower Morrow formations. In addition, we continue to apply our proven geoscience expertise in the search for new exploration opportunities in the greater Midcontinent region.

Maintain Operational Control.

We operated substantially all of the wells that we drilled and completed during 2014, allowing us to effectively manage the timing and levels of our development spending, overall well costs and operating expenses. In addition, we expect to operate the drilling and completion phase on approximately 67% of our 2,765 gross identified drilling locations. With over 80% of our acreage held by existing production, we also will not be required to expend significant capital to hold acreage in our portfolio. We believe that continuing to exercise a high degree of control over our acreage position will provide us with flexibility to manage our drilling program and optimize our returns and profitability.

Focus on Well-Level Returns.

Our management and technical teams are focused on maximizing well-level returns, which we believe drives shareholder value. In addition to our focus on costs and optimizing drilling and completion techniques, our team maximizes returns by allocating capital to areas with the highest rates of return based on commodity mix. Our drilling inventory comprises oil, natural gas and NGLs, which enables us to adjust our development approach based on prevailing commodity prices. Despite recent declines in commodity prices, we currently intend to capitalize on the relatively more favorable oil pricing environment as compared to natural gas and NGLs by continuing to drill acreage with significant oil components, where 100% of our 2015 drilling capital budget is focused. In addition, we expect that continuing to operate the substantial majority of our drilling locations will allow us to reallocate our capital and resources opportunistically in response to market conditions. Our disciplined focus on well-level returns in allocating our capital and resources has been a key component of our ability to deliver successful results through various commodity price cycles.

Competitive Strengths

We possess a number of competitive strengths that we believe will allow us to successfully execute our business strategy:

Geographic Focus in the Prolific U.S. Midcontinent.

Our operations are focused in the Midcontinent region, targeting liquids-rich opportunities in the Anadarko and Arkoma basins of Texas and Oklahoma. We generally focus on formations characterized by oil and liquids-rich natural gas content, extensive production histories, long-lived reserves, high drilling success rates, and attractive initial production rates. Furthermore, our areas of operation are proximate to well-developed natural gas and liquids midstream infrastructure and oilfield services providers, which we believe reduces the risk of production delays and facilitates adequate takeaway capacity. All of our 2015 drilling capital budget is devoted to the Anadarko basin in the U.S. Midcontinent.

Multi-Year Drilling Inventory in Existing and Emerging Resource Plays.

Our drilling inventory consists of approximately 2,765 gross identified drilling locations in the Anadarko and Arkoma basins, and our development plans target locations that we believe are low-cost, provide attractive economics, present low risk, and support a relatively predictable production profile. As of December 31, 2014, we had identified 704 gross drilling locations in the Cleveland play and 777 gross drilling locations in the Arkoma Woodford shale formation. Our concentrated leasehold position has been delineated largely through drilling on our Cleveland leasehold, which we expanded substantially through our Chalker and Sabine acquisitions and more recently increased through our 2014 leasing efforts. We have also expanded through joint development agreements with large independent producers and major oil and gas companies in the Cleveland and Woodford formations. In 2014, we drilled 134 gross wells, as compared to 97 gross wells drilled in 2013, representing a 38%

increase. Furthermore, we have identified additional locations in several emerging resource plays that we intend to explore and develop in the coming years, including 324 gross locations in the Tonkawa formation and 566 gross locations in the Marmaton formation.

Extensive Operational Expertise and Low-Cost Operating Structure.

Drilling horizontal wells has been our primary drilling approach for the last ten years. Having drilled over 590 horizontal wells in nine formations in our areas of operation since 1996, we have established systematic protocols that we believe provide repeatable results. We also have established relationships with oilfield services providers, allowing for continued cost efficiencies. As an example, we have consistently drilled horizontal Cleveland wells at a meaningfully lower cost than most of our competition in the same area. Through our focus on drilling, completion and operational efficiencies, we are able to effectively control costs and deliver attractive rates of return and profitability.

Strong Financial Position and Conservative Policies.

We are committed to maintaining a conservative financial profile in order to preserve operational flexibility and financial stability. We believe that our operating cash flow, together with projected availability under our senior secured revolving credit facility, provide us with the financial flexibility to pursue acquisitions, joint development agreements and organic leasing opportunities. In addition, we have historically hedged a significant amount of our production from oil, gas and NGLs. For the three years ended December 31, 2014, approximately 70% of our total production was protected by commodity hedges. Our hedge position is reviewed monthly to evaluate the impact of new wells coming online and changes to our development program. We intend to continue to actively hedge our future production in order to reduce the impact of commodity price volatility on our cash flows and secure our rates of return for up to five years. As of December 31, 2014, the market value of our existing hedges with the lenders under our senior secured credit facility was approximately $208.5 million.

High Caliber Management Team with Deep Operating Experience and a Proven Track Record.

The top four executives of our management team average more than 25 years of industry experience. Furthermore, our entire management team averages over 20 years of industry experience and has worked together developing assets for many years, resulting in a high degree of continuity. We have assembled a strong technical staff of geoscientists, field operations managers and engineers with significant experience drilling horizontal wells and with fracture stimulation of unconventional formations, which has resulted in a successful track record of reserve and production growth. In addition, our management team has extensive expertise and operational experience in the oil and natural gas industry with a proven track record of successfully negotiating, executing and integrating acquisitions. Members of our management team have previously held positions with major and large independent oil and natural gas companies, including ExxonMobil, BP, Southwestern Energy, Samson, Marathon and Standard Oil.

Alignment of Management Team.

Our predecessor company was founded in 1988 by our CEO, Jonny Jones, in continuation of his family's history in the oil and gas business, which dates back to the 1920's. Jones family members and our management team controlled approximately 28% of our combined voting power and economic interest as of December 31, 2014. We believe the equity interests of our officers and directors align their interests and provide substantial incentive to grow the value of our business.

Recent Developments

Public Offering of Class A Common Stock

On February 17, 2015, we completed the issuance and sale of 7,500,000 shares of Class A common stock to the public at a price of $10.25 per share under our registration statement on Form S-3 (the "Public Equity Offering"). The shares of Class A common stock were issued pursuant to an underwriting agreement, dated February 11, 2015, in which we granted the underwriters a 30-day option to purchase up to an additional 1,125,000 shares of Class A common stock.

Private Placement of Class A Common Stock

On February 23, 2015, we completed the sale of an aggregate of $50.0 million of Class A common stock to certain affiliates of GSO Capital Partners LP and Magnetar Capital LLC in a direct placement of registered shares under our registration statement on Form S-3 (the "Private Equity Offering"). Under the terms of the Private Equity Offering, we sold 4,761,905 shares of Class A common stock at a purchase price of $10.50 per share.

Private Placement of Senior Unsecured Notes

On February 23, 2015, JEH and Jones Energy Finance Corp., a wholly-owned subsidiary of JEH formed for the sole purpose of co-issuing certain of JEH's debt, completed the sale of $250.0 million in aggregate principal amount of 9.25% senior unsecured notes due 2023 (the "2023 Notes") to certain affiliates of GSO Capital Partners LP and Magnetar Capital LLC in a private placement (the "Notes Offering"). The 2023 Notes rank equally with all of our other senior unsecured indebtedness and are effectively subordinated in right of payment to all of our secured indebtedness (to the extent of the collateral securing such indebtedness). The 2023 Notes are fully and unconditionally guaranteed on a senior unsecured basis by Jones Energy, Inc. and by all of JEH's existing subsidiaries (other than the co-issuer and two immaterial subsidiaries) and any future subsidiaries that guarantee indebtedness under our senior secured revolving credit facility or other debt securities.

We used the net proceeds from the Public Equity Offering, the Private Equity Offering and the Notes Offering for working capital and to repay outstanding borrowings under our senior secured revolving credit facility.

Our Operations

Our Areas of Operations

We own leasehold interests in oil and natural gas producing properties, as well as in undeveloped acreage, substantially all of which are located in the Anadarko and Arkoma basins in Texas and Oklahoma. The majority of our interests are in producing properties located in fields characterized by what we believe to be long-lived, predictable production profiles and repeatable development opportunities. Specifically, our properties and wells are located in fields that generally have been developed over a long period of time, typically decades. Given the long productive history of these fields, there is substantial midstream and service infrastructure in place, including natural gas and NGL pipelines and natural gas processing plants. Observing the performance of these fields over many years allows for greater understanding of production and reservoir characteristics, making future performance more predictable. For a discussion of the risks inherent in oil and natural gas production, please read "Risk Factors—Drilling for and producing oil, natural gas and NGLs are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations."

Anadarko Basin

Approximately 75% of our estimated proved reserves as of December 31, 2014 and approximately 77% of our average daily net production for the year ended December 31, 2014 were located in the Anadarko basin. The Anadarko basin is one of the most prolific oil and natural gas producing basins in the United States, covering approximately 50,000 square miles primarily in Oklahoma, but also including the upper Texas Panhandle, southwestern Kansas, and southeastern Colorado.

The basin has an especially well developed interval of productive Pennsylvanian age sedimentary rocks, up to 15,000 feet thick. Our wells in this area produce oil, natural gas and NGLs from various formations at depths from approximately 7,000 feet to 12,000 feet. We drilled 116 gross (97 net) wells as operator in the Anadarko basin in 2014. Our operations in the Anadarko basin are primarily focused on the Cleveland formation where we have 502 producing wells. We also have acreage in the Tonkawa, Marmaton, Granite Wash, Atoka shale and Cherokee shale formations located in the eastern portion of the Texas Panhandle and western Oklahoma.

Producing Formations. Our production in the Anadarko basin is currently derived primarily from the following formations, where we have 542 gross (382 net) producing wells and where we have identified 1,988 gross (1,030 net) drilling locations as of December 31, 2014, of which 420 have proved undeveloped reserves attributed to them as of December 31, 2014. See "Drilling Locations" for more information regarding the processes and criteria through which these drilling locations were identified.

- ***Cleveland Formation.*** Our Cleveland acreage is primarily located in Ochiltree, Lipscomb, Hutchinson, and Hemphill Counties in Texas and Ellis County in Oklahoma. The Cleveland formation ranges from depths of approximately 7,000 feet to 8,800 feet and is characterized by a tight, shaly sand with low permeability that lends itself to improved recovery through enhanced drilling and completion techniques.

  As of December 31, 2014, we operated 379 gross (304 net) producing wells with an average working interest of 80%. Our Cleveland properties contained 83.0 MMBoe of estimated net proved reserves as of December 31, 2014, 64% of which are oil and NGLs, and generated an average daily net production of 17.0 MBoe/d for the year ended December 31, 2014. We have identified 704 gross (477 net) drilling locations in the Cleveland formation as of December 31, 2014. Of these 704 locations, 364 locations (52%) are attributable to proved undeveloped reserves as of December 31, 2014. We are currently running three rigs in the Cleveland formation and plan to spend 100% of the Company's development budget, or approximately $190 million, drilling and completing wells there in 2015.

- ***Tonkawa Formation.*** As of December 31, 2014, we have identified 324 gross (190 net) drilling locations in the Tonkawa formation primarily in Lipscomb and Hemphill Counties in Texas. In addition, the Tonkawa formation is present in the area of other properties we own located primarily in Ellis and Roger Mills Counties in Oklahoma. The Tonkawa is a newly-targeted horizontal oil formation at depths of approximately 6,000 feet to 8,000 feet and is characterized by fine to very fine-grained shallow marine sandstone, ranging in thickness from 20 feet to 40 feet.

  We drilled our first horizontal Tonkawa well in May 2010 and drilled two additional horizontal wells in the formation under a farm-out with Samson that is not part of our current leasehold. During 2014, we drilled six additional test wells in different areas of the Company's leasehold acreage in the Tonkawa formation. We have not allocated any capital expenditures to the Tonkawa formation in our 2015 drilling budget.

- ***Marmaton Formation.*** As of December 31, 2014, we have identified 566 gross (334 net) drilling locations in the Marmaton formation. Our properties in the Marmaton formation are all undeveloped and span three sub- formations: properties located primarily in Ellis County, Oklahoma characterized by fluvio-deltaic sands, properties located primarily in Northeast Ochiltree and Northwest Lipscomb Counties, Texas, characterized by shallow marine sands, and properties located primarily in Ochiltree County, Texas characterized by algal reef complex. The Marmaton sand is a tight, shaly sand with similar reservoir characteristics to the Cleveland. The Marmaton sand ranges in thickness from 40 feet to 80 feet while the reef ranges from 80 feet to 150 feet. We have not allocated any capital expenditures to the Marmaton formation in our 2015 drilling budget.

- ***Granite Wash Formation.*** Our Granite Wash acreage is primarily located in Roberts, Hemphill and Wheeler Counties in Texas and Roger Mills, Beckham, Custer and Washita Counties in Oklahoma. The Granite Wash spans multiple zones from depths of approximately 9,000 feet to 12,000 feet and is composed of stacked, low permeability, variable lithology alluvial fan deltaic deposits.

  As of December 31, 2014, we operated 28 gross (20 net) producing wells in this formation with an average working interest of 71%. Our Granite Wash properties contained 3.5 MMBoe of estimated net proved reserves as of December 31, 2014, approximately 41% of which are oil and NGLs. We have not allocated any capital expenditures to the Granite Wash formation in our 2015 drilling budget. We have 394 gross (29 net) remaining drilling locations in the Granite Wash formation as of December 31, 2014.

Future Potential Opportunities. Our current leasehold position provides longer term potential exposure to other prospective formations in the Anadarko basin, including the Atoka, Cherokee, Douglas, Cottage Grove, and Upper and Lower Morrow formations. The Atoka and Cherokee formations, in particular, have attractive geologic properties, and we may elect to pursue their development in the future.

Arkoma Basin

Approximately 22% of our estimated proved reserves as of December 31, 2014, and approximately 18% of our average daily net production for the year ended December 2014, were located in the Arkoma basin. The Arkoma basin is a historically prolific, largely gas-prone basin extending from eastern Oklahoma into western Arkansas. The basin produces natural gas, oil and NGLs from multiple horizons, which range in depth from 500 to 21,000 feet.

As of December 31, 2014, we operated approximately 55% of our properties in the Arkoma basin and produce primarily from the Woodford formation. Our current leasehold position also provides longer term potential exposure to other prospective formations in the Arkoma basin, including the Hartshorne, Spiro, Wapanuka, Cromwell and Caney formations.

- ***Woodford Shale Formation.*** Our properties in the Woodford shale formation are located primarily in Atoka, Coal, Pittsburg and Hughes Counties in eastern Oklahoma. The Woodford shale formation ranges from depths of approximately 5,000 feet to 12,700 feet and is composed of 75 to 220-foot thick black siliceous shale in our operating area. The Woodford shale in this area is prospective for natural gas with a high concentration of associated NGLs.

  As of December 31, 2014, we operated 93 gross (50 net) producing wells in the formation with an average working interest of 54%. Our Woodford shale formation properties contained 25.4 MMBoe of estimated net proved reserves as of December 31, 2014, 43% of which are oil and NGLs, and generated an average daily net production of 4.0 MBoe/d for the year ended December 31, 2014. We drilled 17 gross (11 net) additional wells in the Woodford shale formation in 2014. We have identified 777 gross (85 net) drilling locations in the Woodford shale formation as of December 31, 2014, of which 13% have proved undeveloped reserves attributed to them as of December 31, 2014. Of these 777 locations, 351 gross (24 net) locations are available through our agreement with Vanguard Natural Resources. As of December 31, 2014, we have drilled five of the eight wells required to earn the acreage available under the Vanguard agreement. Drilling the three remaining wells will allow us to continue development and earn additional locations under the Vanguard agreement, which is otherwise subject to expiration in the event such drilling has not begun by April 2016. We have not budgeted any 2015 capital expenditures in the Arkoma basin.

Drilling Locations

We have identified a total of 2,765 gross (1,115 net) drilling locations, all of which are horizontal drilling locations. Of these 2,765 locations, 1,937 locations are attributable to acreage that is currently held by production and approximately 518 (19%) are attributable to proved undeveloped reserves as of December 31, 2014. In order to identify drilling locations, we apply geologic screening criteria based on the presence of a minimum threshold of reservoir thickness in a section and then consider the number of sections and the appropriate well density to develop the applicable field. In making these assessments, we include properties in which we hold operated and non-operated interests, as well as redevelopment opportunities. Once we have identified acreage that is prospective for the targeted formations, well placement is determined primarily by the regulatory spacing rules prescribed by the governing body in each of our operating areas. Wells drilled in the Cleveland formation adhere to 128-acre spacing (5 wells per section) while wells in the Woodford shale formation are developed on 80-acre and 120-acre spacing, depending on the area. Wells drilled in the Granite Wash formation were developed on 128-acre or 213-acre spacing. Wells drilled in the Tonkawa and Marmaton formations adhere to 160-acre spacing. We view the risk profiles for the Tonkawa and Marmaton formations as being higher than for our other drilling locations due to relatively less available production data and drilling history.

Our identified drilling locations are scheduled to be drilled over many years. The ultimate timing of the drilling of these locations will be influenced by multiple factors, including oil, natural gas and NGL prices, the availability and cost of capital, drilling, completion and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, processing, marketing and pipeline transportation constraints, regulatory approvals and other factors. In addition, a number of our identified drilling locations are associated with joint development agreements, and if we do not meet our obligation to drill the minimum number of wells specified in an agreement, we will lose the right to continue to develop certain acreage covered by that agreement. For a discussion of the risks associated with our drilling program, see "Risk Factors—Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent or delay associated expected production. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations."

Estimated Proved Reserves

The following table sets forth summary data with respect to our estimated net proved oil, natural gas and NGLs reserves as of December 31, 2014, 2013 and 2012, which are based upon reserve reports of Cawley, Gillespie & Associates, Inc., ("Cawley Gillespie"), our independent reserve engineers.

Cawley Gillespie's reports were prepared consistent with the rules and regulations of the SEC regarding oil and natural gas reserve reporting in effect during such periods.

	As of December 31,		
	2014	**2013**	**2012**
Reserve Data:			
Estimated proved reserves:			
Oil (MBbls)	27,683	16,688	12,540
Natural gas (MMcf)	292,277	236,648	228,080
NGLs (MBbls)	38,870	32,915	34,746
Total estimated proved reserves (MBoe)(1)	115,266	89,045	85,300
Estimated proved developed reserves:			
Oil (MBbls)	10,773	7,129	4,262
Natural gas (MMcf)	160,877	139,623	110,956
NGLs (MBbls)	22,555	19,101	16,320
Total estimated proved developed reserves (MBoe)(1)	60,141	49,501	39,075
Estimated proved undeveloped reserves:			
Oil (MBbls)	16,910	9,559	8,278
Natural gas (MMcf)	131,400	97,025	117,124
NGLs (MBbls)	16,315	13,814	18,426
Total estimated proved undeveloped reserves (MBoe)(1)	55,125	39,544	46,225
PV-10 (in millions)(2)	$ 1,502	$ 1,017	$ 782
Standardized measure (in millions)(3)	1,388	941	782

(1) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See "Reconciliation of PV-10 to Standardized Measure" below.

(3) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, Extractive Activities—Oil and Gas. Prior to the reorganization that occurred in 2013 in connection with the initial public offering of Jones Energy, Inc. (the "IPO") of shares of its Class A common stock, the predecessor of Jones Energy, Inc. was a limited liability company that was not subject to entity- level taxation during the periods presented except for the Texas franchise tax. Accordingly, standardized measure for historical periods was not reduced for income taxes. However, upon consummation of the IPO, Jones Energy, Inc. became subject to entity-level taxation, which is reflected in the standardized measure beginning with December 31, 2013.

The following table sets forth the benchmark prices used to determine our estimated proved reserves for the periods indicated.

	As of December 31,		
	2014	2013	2012
Oil, Natural Gas and NGLs Benchmark Prices:			
Oil (per Bbl)(1)	$94.99	$96.78	$94.71
Natural gas (per MMBtu)(2)	4.35	3.67	2.76
NGLs (per Bbl)(3)	33.17	28.33	31.27

(1) Benchmark prices for oil reflect the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months using WTI Cushing posted prices. These prices were utilized in the reserve reports prepared by Cawley Gillespie and in management's internal estimates and are adjusted by well for content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. As of December 31, 2014, 2013 and 2012, the average realized prices for oil were $91.06, $91.74 and $90.74 per Bbl, respectively.

(2) Benchmark prices for natural gas in the table above reflect the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months, respectively, using Henry Hub prices. These prices were utilized in the reserve reports prepared by Cawley Gillespie and in management's internal estimates and are adjusted by well for content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. As of December 31, 2014, 2013 and 2012, the average realized prices for natural gas were $4.16, $3.13 and $2.24 per MMBtu, respectively.

(3) Prices for NGLs in the table above reflect the average realized prices for the prior 12 months assuming ethane is recovered from the natural gas stream. Benchmark prices for NGLs vary depending on the composition of the NGL basket and current prices for the various components thereof, such as butane, ethane, and propane, among others. Due to declines in ethane prices relative to natural gas prices, beginning in 2012, purchasers of our Woodford production have been electing not to recover ethane from the natural gas stream and instead are paying us based on the natural gas price for the ethane left in the gas stream. As a result of the increased energy content associated with the returned ethane and the absence of plant shrinkage, this ethane rejection has increased the incremental revenue and volumes that we receive for our natural gas product relative to what we would have received if the ethane was separately recovered, but has reduced physical barrels of liquid ethane that we are selling.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2014, 2013 and 2012.

	As of December 31,		
	2014	2013	2012
	(in millions)		
PV-10	$1,502	$1,017	$782
Present value of future income taxes discounted at 10%	114	76	—
Standardized measure	$1,388	$ 941	$782

Prior to the IPO, the Company was not subject to federal income tax; hence no income taxes were applied to reserve values in the previous years.

Internal Controls

Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent from our operating teams. We maintain internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by our senior management team on a semi-annual basis. The audit committee of our board of directors conducts a similar review on an annual basis. We expect to have our reserve estimates evaluated by Cawley Gillespie, our independent third-party reserve engineers, or another independent reserve engineering firm, at least annually.

Our internal professional staff works closely with Cawley Gillespie, to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. We provide all of the reserve information maintained in our secure reserve engineering database to the external engineers, as well as other pertinent data, such as geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves. Various procedures are used to ensure the accuracy of the data provided to our independent petroleum engineers, including review processes. Changes in reserves from the previous report are closely monitored. Reconciliation of reserves from the previous report, which includes an explanation of all significant changes, is reviewed by both the engineering department and upper management, including our chief operating officer. Our independent petroleum engineers prepare our annual reserves estimates, whereas interim estimates are internally prepared.

Technology Used to Establish Proved Reserves

Under SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Cawley Gillespie employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and well completion using similar techniques.

Qualifications of Responsible Technical Persons

Internal engineer. Eric Niccum, our Executive Vice President and Chief Operating Officer, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Niccum is also responsible for liaising with and oversight of our third-party reserve engineer. Mr. Niccum is a graduate of Purdue University with a Bachelor of Science degree in Mechanical Engineering. He has 21 years of energy experience.

Cawley Gillespie. Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists. The firm has provided petroleum consulting services to the oil and gas industry for over 50 years. No director, officer, or key employee of Cawley Gillespie has any financial ownership in us or any of our affiliates. Cawley Gillespie's compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Cawley Gillespie has not performed other work for us that would affect its objectivity. The engineering audit presented in the Cawley Gillespie report was supervised by W. Todd Brooker, Senior Vice President at Cawley Gillespie. Mr. Brooker is an experienced reservoir engineer having been a practicing petroleum engineer since 1989. He has more than 24 years of experience in reserves evaluation and joined Cawley Gillespie as a reserve engineer in 1992. He has a Bachelors of Science Degree in Petroleum Engineering from the University of Texas at Austin and is a Registered Professional Engineer in the State of Texas (License No. 83462).

Development of Proved Undeveloped Reserves

As of December 31, 2014, none of our proved undeveloped reserves at December 31, 2014 were scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. However, certain of our proved undeveloped reserves are associated with joint development agreements with third parties that include obligations to drill a specified minimum number of wells in a time frame that is shorter than five years. 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 in some cases would result in a reduction in our proved undeveloped reserves. Historically, our drilling and development programs were substantially funded from our cash flow from operations. Our expectation is to continue to fund our drilling and development programs primarily from our cash flow from operations and projected availability under our senior secured revolving credit facility. Based on our current expectations of our cash flows and drilling and development programs, which include drilling of proved undeveloped locations, we believe that we can fund the drilling of our current inventory of proved undeveloped locations and our expansion activities in the next five years from our cash flow from operations and borrowings under our credit facilities. For a more detailed discussion of our liquidity position, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Our proved undeveloped reserves have increased from 39.5 MMBoe at December 31, 2013 to 55.1 MMBoe at December 31, 2014 due to (i) the conversion of 10.1 MMBoe of proved undeveloped reserves to proved developed reserves; (ii) additions and net positive revisions of 0.2 MMBoe, primarily due to increased interest in existing locations and increased gas commodity pricing; (iii) additions of 15.7 MMBoe from extensions and discoveries; and (iv) additions of 9.8 MMBoe for purchases of minerals in place. Proved undeveloped reserves increased as a percentage of total reserves from 44% for the year ended December 31, 2013 to 48% for the year ended December 31, 2014. For the year ended December 31, 2014, we converted 10.1 MMBoe of proved undeveloped reserves to proved developed reserves or 26% of total proved undeveloped reserves booked at December 31, 2013. We incurred approximately $164 million in capital to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2014. Our 2014 capital expenditures, excluding acquisitions, totaled $524 million, $494 million of which was used to drill and complete wells. We expect our 2015 capital expenditure budget to be approximately $210 million, $190 million of which we expect to use to drill and complete wells. Costs of proved undeveloped reserve development in 2014 do not represent the total costs of these conversions, as additional costs may have been recorded in previous years. Estimated future development costs relating to the development of 2014 year-end proved undeveloped reserves is $940 million.

Operating Data

The following table sets forth summary data regarding production volumes, average prices and average production costs associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2014	2013	2012
Production and Operating Data:			
Net Production Volumes(1):			
Oil (MBbls)	2,475	1,557	746
Natural gas (MMcf)	21,922	17,575	14,066
NGLs (MBbls)	2,345	1,724	1,773
Total (MBoe)	8,474	6,210	4,863
Average net production (Boe/d)	23,216	17,014	13,287
Average Sales Price(2):			
Oil (per Bbl)	$ 88.93	$ 93.22	$ 89.71
Natural gas (per Mcf)	3.78	3.16	2.17
NGLs (per Bbl)	32.14	33.30	29.07
Combined (per Boe) realized	44.65	41.56	30.63
Average Unit Costs per Boe:			
Lease operating expense	$ 5.17	$ 4.47	$ 4.75
Production tax expense	2.14	2.07	1.15
Depreciation, depletion and amortization	21.44	18.38	16.60
General and administrative expense(3)	3.04	5.14	3.26

(1) The Lipscomb SE field constituted approximately 23% of our estimated proved reserves as of December 31, 2014. Our production from the Lipscomb SE field was 2,862 MBoe and 1,751 MBoe for the years ended December 31, 2014 and 2013, respectively. The 2014 production was comprised of 1,274 MBbls of oil, 5,337 MMcf of natural gas and

699 MBbls of NGLs. The 2013 production was comprised of 858 MBbls of oil, 2,786 MMcf of natural gas and 430 MBbls of NGLs. The 2012 production was comprised of 17 MBbls of oil, 61 MMcf of natural gas and 9 MBbls of NGLs.

(2) Prices do not include the effects of derivative cash settlements.

(3) General and administrative includes non-cash stock-based compensation of $4.8 million, $13.6 million and $0.6 million for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per Boe of $2.47, $2.95 and $3.15 for the years ended December 31, 2014, 2013 and 2012, respectively.

Drilling Activity

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	132	108	97	61	44	22
Mechanical failure	1	1	—	—	2	1
Dry	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry	1	1	—	—	2	1
Total Wells:						
Productive	132	108	97	61	44	22
Mechanical failure	1	1	—	—	2	1
Dry	1	1	—	—	2	1
Total	134	110	97	61	48	24

For the three years ended December 31, 2014, we had no developmental wells that were deemed dry wells and three gross (two net) exploratory wells deemed dry wells. In this same period, we experienced a total of three gross (two net) mechanical failures that were not reservoir related. As of December 31, 2014, there were 32 gross (27 net) development wells in the process of drilling or completion. For the three years ended December 31, 2014, we drilled 279 gross (195 net) wells as operator with over a 98% success rate.

From January 1, 2014 through December 31, 2014, we successfully drilled 51 gross proved undeveloped wells and completed 44 gross proved undeveloped wells.

Productive Wells

The following table sets forth our total gross and net productive wells by oil or natural gas classification as of December 31, 2014.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated(1)	252	198	315	232	567	430
Non-operated	61	13	319	68	380	81
Total	313	211	634	300	947	511

(1) Includes wells on which we act as contract operator.

Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage Data

The following table sets forth certain information regarding the developed and undeveloped acreage in which we have an interest as of December 31, 2014 for each of our producing areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. Acreage that is prospective for the Tonkawa, Marmaton and other formations is included in these totals as these formations overlie one another throughout much of our acreage. As of December 31, 2014, over 80% of our leasehold acreage was held by existing production.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Cleveland	137,787	87,326	24,793	21,934	162,580	109,260
Granite Wash	10,553	6,617	—	—	10,553	6,617
Woodford(1)	12,363	4,379	4,929	848	17,292	5,227
Other	19,593	7,444	7,997	2,954	27,590	10,398
All properties(2)	180,296	105,766	37,719	25,736	218,015	131,502

(1) Excludes unearned gross and net acreage associated with the Vanguard joint development agreement. Earned acreage associated with the Vanguard joint development agreement is assigned to us at the time the first well in each unit is completed.

(2) Includes undeveloped acreage associated with joint development agreements with third parties. 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. Please see "Risk Factors—If we do not fulfill our obligation to drill the minimum number 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."

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2014 that will expire over the next three years by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates or unless the existing leases are renewed prior to expiration.

	Expiring 2015		Expiring 2016		Expiring 2017	
	Gross	Net	Gross	Net	Gross	Net
Cleveland	5,760	5,318	2,590	2,438	12,136	9,897
Woodford	3,146	499	20	—	—	—
Granite Wash	—	—	—	—	—	—
Other	2,456	509	2,448	1,149	1,575	43
All properties	11,362	6,326	5,058	3,587	13,711	9,940

A majority of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations have commenced or production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of operations or production in commercial quantities. We also have options to extend some of our leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third-party leases that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date. We do not have any of our proved undeveloped reserves as of December 31, 2014 attributed to acreage whose lease expiration date precedes the scheduled initial drilling date. Our leases are mainly fee leases with primary terms of three to five years. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Competition

The oil and natural gas industry is highly competitive. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well-established companies and have financial and other resources substantially greater than ours. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please read "Risk Factors—We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues."

We are also affected by competition for drilling rigs, equipment, services, supplies and qualified personnel. Recently, the United States onshore oil and natural gas industry has begun to experience a surplus of drilling and completion rigs, equipment, pipe and personnel, due to significantly lower commodity prices. Although this has provided a temporary respite from the previous high demand environment, there is no assurance that market forces will not revert to the previous situation which resulted in delayed development drilling and other exploration activities and caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such changes may occur or how they would affect our development and exploitation programs.

Segment Information and Geographic Areas

The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas, and all of its operations are conducted in one geographic area of the United States, as described under "—Our Operations—Our Areas of Operations."

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%. Our net revenue interests average 55% for our operated leases and 38% including all operated and non-operated leases.

Over 80% of our leases (based on net acreage) are held by production and do not require lease rental payments.

Marketing and Major Customers

Our oil is generally sold under short-term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for oil and liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. We do not own any oil or liquids pipelines or other assets for the transportation of those commodities, and transportation costs related to moving oil are deducted from the price received for oil. In September of 2014, the Company signed a 10-year oil gathering and transportation agreement with Monarch Oil Pipeline LLC, pursuant to which Monarch Oil Pipeline, LLC will build at its expense a new oil gathering system and connect to dedicated Company leases in Texas. The system is expected to begin service during the second quarter of 2015 and provide connectivity to both a regional refinery market as well as the Cushing market hub. Jones Energy has reserved capacity of up to 12,000 barrels per day on the system with the potential to increase throughput at a future date.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to natural gas gathering and marketing companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees. On virtually all of our natural gas production, we are paid for the extracted NGLs based on a negotiated percentage of the proceeds that are generated from the customer's sale of the liquids, or based on other negotiated pricing arrangements. We do not own any natural gas pipelines or other assets for the transportation of natural gas.

Recently, changes in NGL prices have altered market conditions. Due primarily to the large supply of the major NGL component products on the market, the composite price of NGL components have dropped significantly over the last year. For a discussion of the effect of recent changes in NGL prices, see "Management's Discussion and Analysis of Financial Condition and Results of Operations— Outlook."

During the year ended December 31, 2014, the largest purchasers were Valero Energy Corp., NGL Energy Partners LP, PVR Midstream LLC, Plains Marketing LP, and Monarch Natural Gas, LLC, which accounted for approximately 22%, 12%, 12%, 10% and 10% of consolidated oil and gas sales, respectively. If we were to lose any one of our customers, the loss could temporarily delay production and sale of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether, the loss of such customer could have a detrimental effect on our production volumes in general and on our ability to find substitute customers to purchase our production volumes. For a discussion of the risks associated with the loss of key customers, please read "Risk factors—Our customer base is concentrated, and the loss of any one of our key customers could, therefore, adversely affect our financial condition and results of operations."

Seasonality

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to material defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We conduct a portion of our operations through joint development agreements with third parties. Certain of our joint development agreements include complete-to-earn arrangements, whereby we are assigned title to properties from the third-party after we complete wells. Occasionally, delivery of such assignments may be delayed. Furthermore, certain of our joint development agreements specify that assignments are only to occur when the wells are capable of producing hydrocarbons in paying quantities. These additional conditions to assignment of title may from time to time apply to wells of substantial value.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10-K.

Regulations

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and limit the number of wells or locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress and federal agencies, the states, and the courts. We cannot predict when or whether any such proposals may become effective. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations that govern the protection of the environment, as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of pollution control equipment in connection with operations;
- restrict or prohibit our drilling and production activities during periods when such activities might affect wildlife;
- place restrictions or regulations upon the types, quantities or concentrations of materials or substances used in our operations;
- restrict the types, quantities or concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, federal, state and local lawmakers and agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Solid and Hazardous Waste Handling and Releases

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous waste. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, production and transportation of oil and gas are currently excluded from regulation as hazardous wastes under RCRA. In the course of our operations, however, we generate some industrial wastes, such as paint wastes, waste solvents, and waste oils, which may be regulated as hazardous wastes. Although a substantial amount of the waste generated in our operations are regulated as non-hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous waste. Moreover, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as "Superfund," and comparable state laws and regulations impose liability without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so-called potentially responsible parties, or PRPs, include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency, or the EPA, and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substances and may have disposed of these wastes at disposal sites owned and operated by others. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to the RCRA, CERCLA, and analogous state laws. Spills or other contamination required to be remediated have not required material capital expenditures to date. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States, a term broadly defined. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs. The EPA and the U.S. Army Corps of Engineers recently proposed a rule to clarify the term "waters of the United States." The proposed rule may expand federal jurisdiction under the Clean Water Act, if it is made final in its current form. The EPA has also announced its intention to propose regulations under the Clean Water Act to develop standards for wastewater discharges from hydraulic fracturing and other natural gas production activities.

Safe Drinking Water Act

The SDWA regulates, among other things, underground injection operations. Congress has considered legislation which, if successful, would impose additional regulation under the SDWA upon the use of hydraulic fracturing fluids. If enacted, such legislation could impose on our hydraulic fracturing operations permit and financial assurance requirements, requirements that we adhere to construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the process could adversely affect ground water. In addition, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to the Underground Injection Control program in states in which the EPA is the permitting authority and released permitting guidance on the use of diesel fuel as an additive in hydraulic fracturing fluids. The EPA has also commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, and a committee of the U.S. House of Representatives has commenced its own investigation into hydraulic fracturing practices. The Department of Energy also studied hydraulic fracturing and provided broad recommendations regarding best practices and other steps to enhance companies' safety and environmental performance of hydraulic fracturing. If the pending or similar legislation is enacted or other new requirements or restrictions regarding hydraulic fracturing are adopted as a result of these studies, we could incur substantial compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

Other Regulation of Hydraulic Fracturing

On May 19, 2014, the EPA published an advance notice of rulemaking under the Toxic Substances Control Act, to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration and production. Also, the Bureau of Land Management, or

BLM, is considering proposed rules regarding well stimulation, chemical disclosures, and other requirements for hydraulic fracturing on federal and Indian lands. BLM released a proposed rule requiring the disclosure of chemicals used during hydraulic fracturing and addressing drilling plans, water management, and wastewater disposal on federal and Indian lands in May 2012. However, BLM pulled back its proposal in January 2013 after reviewing comments and published an updated proposed rule on May 24, 2013. The Interagency Working Group on Unconventional Natural Gas and Oil was created by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

Hydraulic fracturing is also subject to regulation at the state and local levels. Several states have proposed or adopted legislative or administrative rules regulating hydraulic fracturing operations. For example, the Railroad Commission of Texas, implementing a state law passed in June 2011, adopted the Hydraulic Fracturing Chemical Disclosure Rule on December 13, 2011. The rule requires public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. Additionally, Texas has authorized the Texas Commission on Environmental Quality to suspend water use rights for oil and gas users in the event of serious drought conditions and has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases. Other states that we operate in, including Oklahoma, have adopted similar chemical disclosure measures. Some states, including Texas and Oklahoma, also assert the authority to shut down injection wells that are deemed to contribute to induced seismicity, or seismic activity that is caused by human activity. Please see "Risk Factors—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing and other oil and gas production activities as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production" for a further discussion of state hydraulic fracturing regulation. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Oil Pollution Act

The primary federal law related to oil spill liability is the Oil Pollution Act, or the OPA, which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns strict joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Air Emissions

Our operations may be subject to the Clean Air Act, or CAA, and comparable state and local requirements for the control of emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or injunctions or require us to forego construction, modification or operation of certain air emission sources.

We may incur expenditures in the future for air pollution control equipment in connection with obtaining or maintaining operating permits and approvals for air emissions. For instance, on April 17, 2012, the EPA released final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. The rules became effective on October 15, 2012. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment in addition to leak detection requirements for natural gas processing plants. In October 2012, several challenges to the EPA's rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The case remains in abeyance. The EPA has since made several changes to the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules. These rules that took effect on October 15, 2012, as well as any modifications to these rules or additional rules, could require a number of modifications to our operations including the installation of new equipment. We have already reported some of our facilities as being subject to these rules and have incurred, and will continue to incur, costs to control emissions, and to satisfy reporting and other administrative requirements associated with these rules. Additionally, the EPA has expressed its intent to regulate emissions of methane and volatile organic compounds from the oil and gas sector as a measure to implement the Climate Action Plan. While the EPA has not yet issued a rulemaking, it has released a series of white papers addressing methane reductions from the oil and gas sector. On January 14, 2015, the Federal Administration announced that the EPA will propose a rule in the summer of 2015 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector. A final rule is expected in 2016.

Endangered Species and Migratory Birds

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. Pursuant to the ESA, if a species is listed as threatened or endangered, activities adversely affecting that species or its habitat may be considered "take" and may incur liability. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Criminal liability can attach for even an incidental taking of migratory birds, and the federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and gas companies after dead migratory birds were found near reserve pits associated with drilling activities.

We conduct operations in areas where certain species that are listed as threatened or endangered under the ESA may be present. For example, our operations in the Arkoma basin of Oklahoma overlap with the range of the American Burying Beetle, which is listed as endangered. The presence of endangered or threatened species may force us to modify or terminate our operations in certain areas. Additionally, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or limit future development activity in the affected areas. On March 27, 2014, the U.S. Fish and Wildlife Service listed the Lesser Prairie Chicken as a threatened species under the Endangered Species Act. The designated habitat for the Lesser Prairie Chicken encompasses significant portions of our properties in the Anadarko basin. In a special rule under ESA Section 4(d) released simultaneously with the decision to list the Lesser Prairie Chicken as threatened, the Fish and Wildlife Service will exempt from "take" certain oil and gas and other activities conducted by a participant that result in an "incidental take" of the Lesser Prairie Chicken as long as the participant is enrolled in, and operating in compliance with, a range-wide conservation plan endorsed by the Fish and Wildlife Service. The range-wide conservation plan also includes a Candidate Conservation Agreement with Assurances (CCAA) component that provides "take" coverage for properties enrolled into the CCAA before the listing is effective. To mitigate the risk of liability from "incidental takes" of the Lesser Prairie Chicken, we enrolled affected leasehold interests in the CCAA. However, environmental groups have challenged the listing decision and special 4(d) rule in a suit filed in federal district court in the District of Columbia on June 17, 2014. These groups are attempting to compel a more restrictive listing of the Lesser Prairie Chicken as endangered, rather than threatened, and are seeking to invalidate the special 4(d) rule. While these same environmental groups also filed a notice of intent to sue concerning the CCAA on April 10, 2014, the suit filed in federal court did not include a challenge to the CCAA. The environmental groups' suit could be consolidated with other suits challenging the scientific basis for the listing filed by affected states and the oil and gas industry in Texas and Oklahoma. We continue to evaluate the impact of these rules and legal challenges on our operations. As with any other species in areas that we operate, the listing of the Lesser Prairie Chicken under the Endangered Species Act could force us to incur additional costs and delay or otherwise limit or terminate our operations.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current production activities, as well as any exploration and development plans that may be proposed in the future, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change

More stringent laws and regulations relating to climate change and greenhouse gases, or GHGs, may be adopted in the future and could cause us to incur material expenses in complying with them. Both houses of Congress have actively considered legislation to reduce emissions of GHGs, but no legislation has yet passed. In the absence of comprehensive federal legislation on GHG emission control, the EPA is regulating GHGs as pollutants under the CAA. The EPA has adopted regulations affecting emissions of GHGs from motor vehicles and is also requiring permit review for GHGs from certain stationary sources that emit GHGs at levels above statutory and regulatory thresholds and are otherwise subject to CAA permitting requirements based on emissions of non-GHG regulated air pollutants. We do not believe our operations are currently subject to these permitting requirements, but if our operations become subject to these or other similar requirements, we could incur significant costs to control our emissions and comply with regulatory requirements.

In addition, the EPA has adopted a mandatory GHG emissions reporting program that imposes reporting and monitoring requirements on various types of facilities and industries. On November 9, 2010, the EPA issued final rules to expand its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The rule requires reporting of GHG emissions by regulated entities to the EPA on an annual basis. Reporting was first required in 2012 for emissions occurring in 2011. We are currently required to monitor and report

GHG emissions under this rule, and operational and/or regulatory changes could increase the burden of compliance with GHG emissions monitoring and reporting requirements.

Because of the lack of any comprehensive legislative program addressing GHGs, there is continuing uncertainty regarding the further development of federal regulation of GHG-emitting sources. Additionally, more than 20 states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions to acquire and surrender emission allowances. The federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

In addition to legislative and regulatory developments, plaintiffs have brought judicial actions under common law theories against greenhouse gas emitting companies in recent years. For example, municipal plaintiffs in *Kivalina v. ExxonMobil Corporation, et al*, alleged that the defendant corporations' contributions to global warming caused property damage associated with rising sea levels. Although the plaintiffs in *Kivalina* were ultimately unsuccessful, there is a continuing litigation risk associated with greenhouse gas-emitting activities.

The federal administration also issued a Climate Action Plan in June 2013. Among other things, the Climate Action Plan directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas industry. As previously mentioned, the federal administration announced that the EPA will propose a rule in the summer of 2015 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector, with a final rule expected in 2016. As a result of this continued regulatory focus and other factors, additional GHG regulation of the oil and gas industry remains a possibility. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation of pollution control activities for the years ended December 31, 2014 or 2013. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2015 or that will otherwise have a material impact on our financial position or results of operations in the future. However, we cannot assure you that the passage of more stringent laws and regulations in the future will not have a negative impact on our business activities, financial condition or results of operations.

Offices

We currently lease approximately 43,000 square feet of office space in Austin, Texas at 807 Las Cimas Parkway, Austin, Texas 78746, where our principal offices are located. The primary lease expires in April 2020. We also lease field offices in Canadian, Texas and McAlester, Oklahoma.

Employees

As of December 31, 2014, we had 104 employees, including 34 technical (geosciences, engineering, land), 22 field operations, 36 corporate (finance, accounting, planning, business development, IT, human resources, office management) and 12 management. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services as needed.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. Our reports filed with the SEC are made available to read and copy at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "JONE." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

Through our website, www.jonesenergy.com, you can access, free of charge, electronic copies of all of the documents that we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report on Form 10-K, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

A substantial or extended decline in oil, natural gas or NGL prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil, natural gas and NGLs heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. The markets for oil, natural gas and NGLs historically have been volatile. As an example, during the second half of 2014, the NYMEX-WTI oil price has fallen from more than $100 per Bbl to below $50 per Bbl, the lowest price seen since 2009. These markets will likely continue to be volatile in the future, especially given the current geopolitical conditions. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- regional and worldwide economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil, natural gas and NGLs;
- political conditions regionally, domestically or in other oil and gas-producing regions;
- the level of domestic and global oil and natural gas exploration and production;
- the level of domestic and global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil, natural gas and NGLs and the speculative trading of oil, natural gas and NGLs;
- trading prices of futures contracts;
- price and availability of competitors' supplies of oil, natural gas and NGLs;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- the impact of energy conservation efforts.

NGLs are made up of ethane, propane, isobutane, butane and natural gasoline, all of which have different uses and different pricing characteristics. NGLs comprised 28% of our 2014 production, and we realized an average price of $32 per barrel. An extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

Substantially all of our production is sold to purchasers under contracts with market-based prices. Lower oil, natural gas and NGL prices will reduce our cash flows and the present value of our reserves. If oil, natural gas and NGL prices deteriorate, we anticipate that the borrowing base under our senior secured revolving credit facility, which is revised periodically, may be reduced at some point, which would negatively impact our borrowing ability. Additionally, prices could reduce our cash flows to a level that would require us to borrow to fund our capital budget. Lower oil, natural gas and NGL prices may also reduce the amount of oil, natural gas and NGLs that we can produce economically. Substantial decreases in oil, natural gas and NGL prices could render uneconomic a significant portion of our identified drilling locations. This may result in significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil, natural gas or NGL prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, exploitation, development and production activities. Our oil, natural gas and NGLs exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements and related lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface or subsurface environment;
- declines in oil, natural gas and NGL prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for oil, natural gas and NGLs.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, the following:

- effectively controlling the level of pressure flowing from particular wells;
- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- running tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and

- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas.

The value of our undeveloped acreage could decline if drilling results are unsuccessful.

The success of our horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, declines in oil, natural gas and NGL prices and/or other factors, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Our business requires substantial capital expenditures, and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, exploitation, development and acquisition activities require substantial capital expenditures. Our total capital expenditures for 2014 were $524 million and our budgeted capital expenditures for 2015 are $210 million. Historically, we have funded development and operating activities primarily through a combination of equity capital raised from a private equity partner and our initial public offering, through borrowings under our senior secured revolving credit facility, through the issuance of debt securities and through internal operating cash flows. We intend to finance the majority of our capital expenditures predominantly with cash flows from operations. If necessary, we may also access capital through proceeds from potential asset dispositions, borrowings under our senior secured revolving credit facility and the issuance of additional debt and equity securities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- the estimated quantities of our oil, natural gas and NGL reserves;
- the amount of oil, natural gas and NGLs we produce from existing wells;
- the prices at which we sell our production;
- any gains or losses from our hedging activities;
- the costs of developing and producing our oil, natural gas and NGL reserves;
- take-away capacity;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to conduct our operations at expected levels. Our senior secured revolving credit facility and the indentures governing our senior notes due 2022 (the "2022 Notes") and senior notes due 2023 (the "2023 Notes") may restrict our ability to obtain new debt financing. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, natural gas and NGLs production or reserves, and in some areas a loss of properties.

External financing may be required in the future to fund our growth. We may not be able to obtain additional financing, and financing under our senior secured revolving credit facility and through the capital markets may not be available in the future. Without additional capital resources, we may be unable to pursue and consummate acquisition opportunities as they become available, and we may be forced to limit or defer our planned oil, natural gas and NGLs development program, which will adversely affect the recoverability and ultimate value of our oil, natural gas and NGLs properties, in turn negatively affecting our business, financial condition and results of operations.

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 48% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2014. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, declines in commodity prices could cause us to reevaluate our development plans and delay or cancel development. Delays in the development of our reserves, increases in costs to drill and develop such reserves or declines in commodity prices will reduce the future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our hedging strategy may be ineffective in reducing the impact of commodity price volatility from our cash flows, which could result in financial losses or could reduce our income.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGLs, we enter into commodity derivative contracts for a significant portion of our oil, natural gas and NGL production that could result in both realized and unrealized hedging losses. The extent of our commodity price exposure is related largely to the effectiveness and scope of our commodity derivative contracts. For example, some of the commodity derivative contracts we utilize are based on quoted market prices, which may differ significantly from the actual prices we realize in our operations for oil, natural gas and NGLs. In addition, our senior secured revolving credit facility limits the aggregate notional volume of commodities that can be covered under commodity derivative contracts we can enter into and, as a result, we will continue to have direct commodity price exposure on the unhedged portion of our production volumes. For the years ending December 31, 2015, 2016, and 2017, approximately 37%, 62%, and 77%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2014, will not be covered by commodity derivative contracts.

Our policy has been to hedge a significant portion of our estimated oil, natural gas and NGLs production. However, our price hedging strategy and future hedging transactions will be determined at our discretion. We are not under an obligation to hedge a specific portion of our production. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially higher or lower than current oil, natural gas and NGLs prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases. It is also possible that a larger percentage of our future production will not be hedged as compared with past years, which would result in our oil and natural gas revenues becoming more sensitive to commodity price changes.

In addition, our actual future production may be significantly higher or lower than we estimate at the time we enter into commodity derivative contracts for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the notional amount of our commodity derivative contracts, we might be forced to satisfy all or a portion of our commodity derivative contracts without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, substantially diminishing our liquidity. There may be a change in the expected differential between the underlying commodity price in the commodity derivative contract and the actual price received, which may result in payments to our derivative counterparty that are not offset by our receipt of payments for our production in the field.

As a result of these factors, our commodity derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair their ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. Currently our entire hedge portfolio is hedged directly with banks in our credit agreements, thus allowing hedging without any margin requirements.

During periods of falling commodity prices, our hedge receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The adoption of the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, could have an adverse effect on our ability to use derivatives to reduce the effect of commodity price risk, interest rate and other risks associated with our business.

We use commodity derivatives to manage our commodity price risk. The U.S. Congress adopted comprehensive financial reform legislation that, among other things, establishes comprehensive federal oversight and regulation of over-the-counter derivatives and many of the entities that participate in that market. Although the Dodd-Frank Act was enacted on July 21, 2010, the Commodity Futures Trading Commission, or the CFTC, and the SEC, along with certain other regulators, must promulgate final rules and regulations to implement many of its provisions relating to over-the-counter derivatives. While some of these rules have been finalized, some have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of covered contracts that a trader may own or control separately or in combination, net long or short. The final rules also contained limited exemptions from position limits which would be phased in over time for certain bona fide hedging transactions and positions. The CFTC's original position limits rule was challenged in court by two industry associations and was vacated and remanded by a federal district court. Since that time, the CFTC has reproposed the rule in substantially the same form as the rule that was vacated by the court, but with certain non-substantive changes in response to the court's decision. The CFTC has sought comment on the position limits rule as reproposed, but has yet to issue its final rule. The CFTC also has withdrawn its appeal of the court order vacating the original position limits rule.

If these or similar position limits go into effect in the future, the timing of implementation of the final rules, their applicability to, and impact on, us and the ultimate success of any legal challenge to their validity remain uncertain, and they could have a material adverse impact on us by affecting the prices of or market for commodities relevant to our operations and/or by reducing the availability to us of commodity derivatives.

The Dodd-Frank Act also imposes a number of other new requirements on certain over-the-counter derivatives and subjects certain swap dealers and major swap participants to significant new regulatory requirements, which in certain cases may cause them to conduct their activities through new entities that may not be as creditworthy as our current counterparties, all of which may have a material adverse effect on us. The impact of this regulatory regime on the availability, pricing and terms and conditions of commodity derivatives remains uncertain, but the final requirements could have a materially adverse effect on our ability to hedge our exposure to commodity prices.

If we reduce our use of derivatives as a result of the Dodd-Frank Act, the regulations promulgated under it and the changes to the nature of the derivatives markets, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the Dodd-Frank Act was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil, natural gas and NGLs. Our revenue could, therefore, be adversely affected if commodity prices were to decrease.

Unless we replace our reserves, our reserves and production will naturally decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful exploration, development and acquisition activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil, natural gas and NGL reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be adversely affected.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent or delay associated expected production. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations.

Our management team has identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. Similarly, the use of technologies and the study of producing fields in the same area of producing wells will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient quantities of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In addition, our ability to drill and develop these drilling locations depends on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. In addition, a number of our identified drilling locations are associated with joint development agreements and if we do not meet our obligation to drill the minimum number of wells specified in an agreement, we will lose the right to continue to develop certain acreage covered by that agreement. Because of the uncertainty inherent in these factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire.

If commodity prices decrease, we may be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. Such impairment may be accompanied by a reduction in proved reserves, thereby increasing future depletion charges per unit of production. We may incur impairment charges and related reductions in proved reserves in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Our estimated oil, natural gas and NGLs reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any significant inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of oil, natural gas and NGL reserves. Our estimates of our proved reserve quantities are based upon our reserve report as of December 31, 2014. Reserve estimation is a subjective process of evaluating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a reasonable time.

The process of estimating oil, natural gas and NGL reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding future oil, natural gas and NGL prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Quantities of proved reserves are estimated based on pricing conditions in existence during the period of assessment and costs at the end of the period of assessment. Changes to oil, natural gas and NGL prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields, because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

Over time, we may make material changes to reserve estimates taking into account the results of actual drilling and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, changes in future production cost assumptions could have a significant effect on our proved reserve quantities.

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.

The standardized measure of discounted future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated oil, natural gas and NGL reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil, natural gas and NGL reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month commodities prices for the preceding 12 months without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- commodity price hedging and actual prices we receive for oil, natural gas and NGLs;
- actual cost of development and production expenditures;
- the amount and timing of actual development and production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Prior to the consummation of the IPO, as a limited liability company, we generally were not historically subject to entity-level taxation. Accordingly, our standardized measure for historical periods does not provide for federal or state corporate income taxes because taxable income was passed through to our equity holders. However, upon consummation of the IPO, we became subject to entity-level taxation for federal income tax purposes, and our future income taxes will be dependent upon our future taxable income.

If oil prices decline by $10.00 per Bbl, then our standardized measure as of December 31, 2014 excluding hedging impacts would decrease approximately $201.1 million holding all costs constant. If natural gas prices decline by $1.00 per Mcf, then our standardized measure as of December 31, 2014 excluding hedging impacts would decrease by approximately $136.2 million holding all costs constant. In the event lower commodity prices persist, we would expect the cost of oil field equipment and services to decline, thereby increasing the returns on our potential drilling opportunities.

Over 99% of our estimated proved reserves are located in the Anadarko and Arkoma basins in the Texas Panhandle and Oklahoma, making us vulnerable to risks associated with operating in one geographic area.

Over 99% of our estimated proved reserves as of December 31, 2014 were located in the Anadarko and Arkoma basins in the Texas Panhandle and Oklahoma. Approximately 71% of our 2014 production was from the Cleveland formation where properties are located in four contiguous counties of Texas and Oklahoma. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of oil, natural gas or NGLs. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as our properties producing from the Cleveland formation, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our customer base is concentrated, and the loss of any one of our key customers could, therefore, adversely affect our financial condition and results of operations.

Historically, we have been dependent on a few customers for a significant portion of our revenue. For the year ended December 31, 2014 purchases by our top five customers accounted for approximately 22%, 12%, 12%, 10% and 10%, respectively, of our total oil, natural gas and NGL sales. This concentration of customers may increase our overall exposure to credit risk, and customers will likely be similarly affected by changes in economic and industry conditions. To the extent that any of our major purchasers reduces their purchases of oil, natural gas or NGLs or defaults on their obligations to us, our financial condition and results of operations could be adversely affected.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

In addition, our senior secured revolving credit facility impose certain limitations on our ability to enter into mergers or combination transactions. Our senior secured revolving credit facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, commodity prices, revenues, capital expenditures, operating expenses and costs;
- an inability to successfully integrate the assets we acquire;
- an inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;

- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we obtain no or limited indemnity or other recourse;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing assets; and
- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired assets into our existing operations. The process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, even if we successfully integrate an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

Deficiencies of title to our leased interests could significantly affect our financial condition.

It is our practice, in acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights, not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office to determine mineral ownership before we acquire an oil and gas lease or other developed rights in a specific mineral interest.

Prior to the drilling of an oil or gas well, it is the normal practice in our industry for the operator of the well to obtain a drilling title opinion from a qualified title attorney to ensure there are no obvious title defects on the property on which the well is to be located. The title attorney would typically research documents that are of record, including liens, taxes and all applicable contracts that burden the property. Frequently, as a result of such examinations, certain curative work must be undertaken to correct defects in the marketability of the title, and such curative work entails expense. Our failure to completely cure any title defects may invalidate our title to the subject property and adversely impact our ability in the future to increase production and reserves. Additionally, because a less strenuous title review is conducted on lands where a well has not yet been scheduled, undeveloped acreage has greater risk of title defects than developed acreage. Any title defects or defects in assignment of leasehold rights in properties in which we hold an interest may adversely impact our ability in the future to increase production and reserves, which could have a material adverse effect on our business, financial condition and results of operations.

We conduct a substantial portion of our operations through joint development agreements with third parties. Certain of our joint development agreements include complete-to-earn arrangements, whereby we are assigned title to properties from the third-party after we complete wells and, in the case of certain counterparties, after completion reports relating to the wells have been approved by regulatory authorities whose approval may be delayed. Furthermore, certain of our joint development agreements specify that assignments are only to occur when the wells are capable of producing hydrocarbons in paying quantities. These additional conditions to assignment of title may from time to time apply to wells of substantial value. If one of our counterparties assigned title to a well in which we had earned an interest (according to our joint development agreement) to a third-party, our title to such a well could be adversely impacted. In addition, if one of our counterparties becomes a debtor in a bankruptcy proceeding, or is placed into receivership, or enters into an assignment for the benefit of creditors, after we had earned ownership of, but before we had received title to, a well, certain creditors of the counterparty may have rights in that well that would rank prior to ours.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

From time to time, legislation is introduced that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included repealing many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposing new fees. Among others, proposed changes have included: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical cost amortization period for independent producers; and implementation of a fee on non-producing federal oil and gas leases. The passage of legislation containing some or all of these provisions or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Many of our larger competitors not only drill for and produce oil and natural gas, but also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may have a greater ability to continue drilling activities during periods of low oil, natural gas and NGL prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. Any inability to compete effectively with larger companies could have a material adverse impact on our financial condition and results of operations.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services as well as fees for the cancellation of such services could adversely affect our ability to execute development and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our operation. The cost of oil field services typically fluctuates based on demand for those services. We may not be able to contract for such services on a timely basis, or the cost of such services may not remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel, including hydraulic fracturing equipment, supplies and personnel necessary for horizontal drilling, could delay or adversely affect our development and exploitation operations, which could have a material adverse effect on our financial condition and results of operations.

Our business depends in part on pipelines, transportation and gathering systems and processing facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil, natural gas and NGLs production and could harm our business.

The marketability of our oil, natural gas and NGLs production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, such as trucks, gathering systems and processing facilities owned by third parties. The amount of oil, natural gas and NGLs that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. Also, the transfer of our oil, natural gas and NGLs on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. Our access to transportation options, including trucks owned by third parties, can also be affected by U.S. federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil, natural gas and NGLs production and harm our business.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- adverse weather conditions and natural disasters;
- encountering abnormally pressured formations;
- facility or equipment malfunctions;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil, natural gas and NGLs we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil, natural gas and NGLs, as well as safety matters. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their ultimate effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of oil, natural gas, NGLs or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government, and third parties and may require us to incur substantial costs for remediation.

See "Item 1. Business—Regulations" for a further description of the laws and regulations that affect us.

Our ability to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

- the Clean Air Act, or CAA, and comparable state laws and regulations that impose obligations related to air emissions;
- the Clean Water Act and Oil Pollution Act, or OPA, and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;
- the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal;
- the Environmental Protection Agency's, or the EPA's, community right to know regulations under the Title III of CERCLA and comparable state laws that require that we organize and/or disclose information about hazardous materials used or produced in our operations;
- the Occupational Safety and Health Act, or OSHA, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- the National Environmental Policy Act, or NEPA, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment;
- the Migratory Bird Treaty Act, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing, or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban on operations in affected areas; and
- the Endangered Species Act, or ESA, and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to exploration, development and production activities. These laws and regulations may require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and product transportation pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filing requirements. In addition, these laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the RCRA, CERCLA, the federal OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where petroleum or hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including laws related to climate change and greenhouse gases, may be adopted in the future. The trend of more expensive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment. We are also subject to many other environmental requirements delineated in "Business—Environmental Matters and Regulation."

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing and other oil and gas production activities as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in many of our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, in states where the EPA is the permitting authority and released guidance in February 2014 on regulatory requirements for companies that plan to conduct hydraulic fracturing using diesel in those states. In addition, the EPA issued a notice of rulemaking under the Toxic Substances Control Act relating to chemical substances and mixtures used in oil and gas exploration and production. Congress has also considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process.

Some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations under certain circumstances. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas, or TRRC, and the public of certain information regarding the components of the fluids used in the hydraulic fracturing process. On December 13, 2011, the TRRC finalized regulations requiring public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. In addition, on October 20, 2011, Louisiana adopted new regulations for hydraulic fracturing operations in the state. These new regulations require hydraulic fracturing operators to publicly disclose the volume of hydraulic fracturing fluid, the type, trade name, supplier and volume of additives, and a list of chemical compounds contained in the additive, along with its maximum concentration, subject to certain trade secret protections. However, trade secret chemicals must be identified by their chemical family. The mandatory disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment. In addition, the Oklahoma Corporation Commission has adopted rules prohibiting water pollution resulting from hydraulic fracturing operations and requiring disclosure of chemicals used in hydraulic fracturing.

Texas has also authorized the Texas Commission on Environmental Quality to suspend water use rights for oil and gas users in the event of serious drought conditions and has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases. Also, Louisiana requires operators to minimize releases of gases into the open air after hydraulic fracturing in certain urban areas.

In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released its first progress report on this study in December 2012 and has also released several papers for public and peer review. The study remains ongoing.

The EPA announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and plans to propose pretreatment standards. In addition, the U.S. Department of Energy's Natural Gas Subcommittee of the Secretary of Energy Advisory Board conducted a review of hydraulic fracturing issues and practices and made recommendations to better protect the environment from drilling using hydraulic fracturing completion methods. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms. The Interagency Working Group on Unconventional Natural Gas and Oil was created by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional oil and natural gas resources.

Also, the U.S. Department of the Interior's Bureau of Land Management, or BLM, is considering rules regarding well stimulation, chemical disclosures and other requirements for hydraulic fracturing on federal and Indian lands. BLM released a proposed rule requiring the disclosure of chemicals used during hydraulic fracturing and addressing drilling plans, water management and wastewater disposal, on federal and Indian lands in May 2012. However, BLM pulled back its proposal in January 2013 after reviewing comments and published an updated proposed rule on May 24, 2013.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, some state regulatory agencies have modified their regulations to account for induced seismicity. For example, the Texas Railroad Commission rules allow the Commission to modify, suspend, or terminate a permit based on a determination that the permitted activity is likely to be contributing to seismic activity. The Oklahoma Corporation Commission also asserts authority to shut down injection wells that it considers linked to induced seismicity, and has recently taken other steps to regulate injection wells that may contribute to induced seismicity. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity.

Further, on April 17, 2012, the EPA released final rules to subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. These rules became effective on October 15, 2012. The EPA rules also include NSPS standards for completions of hydraulically-fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. In October 2012, several challenges to the EPA's rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The EPA has since reconsidered several aspects of the rules and may continue to make changes. Depending on the outcome of such judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules. We have reported some of our facilities as being subject to these rules and have incurred, and will continue to incur, costs to control emissions, and to satisfy reporting and other administrative requirements associated with these rules. We continue to evaluate the effect these rules will have on our business. On January 14, 2015, the federal administration announced that the EPA will propose a rule in the summer of 2015 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector. A final rule is expected in 2016. The Administration's announcement also stated that other federal agencies, including the Bureau of Land Management, the Pipeline and Hazardous Materials Safety Administration, and the Department of Energy will impose new or more stringent regulations on the oil and gas sector that will have the effect of further reducing methane emissions. Increased regulation and attention given to the hydraulic-fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic-fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale formations, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil, natural gas and NGLs we produce; and actual impacts of climate change like extreme weather conditions could adversely affect our operations.

In December 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA promulgated regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one rule that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States. On November 9, 2010, the EPA issued final rules to expand its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities with reporting of GHG emissions from such facilities required on an annual basis. The first reports were due in 2012 for emissions occurring in 2011. We are currently required to monitor and report GHG emissions under this rule, and operational and/or regulatory changes could increase the burden of compliance with GHG emissions monitoring and reporting requirements.

The Climate Action Plan also calls for reductions of methane emissions. As previously mentioned, the federal administration has previously announced that the EPA will issue a proposed rule to require methane reductions from oil and gas sources in the summer of 2015, with a final rule expected in 2016. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, natural gas and NGLs we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our gas production operations. Productive zones frequently contain water that must be removed in order for the gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce gas in commercial quantities. The produced water currently is transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the EPA expects to issue new standards regarding the disposal of wastewater from hydraulic fracturing into publicly owned treatment facilities. Therefore, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

In the event water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow available for drilling and place us at a competitive disadvantage. For example, as of December 31, 2014, we had approximately $265 million of total available borrowing capacity under our revolving credit facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full $625 million available under our revolving credit facility would result in increased annual interest expense of approximately $6 million and a corresponding decrease in our net income. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We conduct a substantial portion of our operations through farm-outs, areas of mutual interest and other joint development agreements. These agreements subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a substantial portion of our operations through joint development agreements with third parties, including ExxonMobil and Vanguard Natural Resources. We may also enter into other joint development agreements in the future. These third parties may have obligations that are important to the success of the joint development agreement, such as the obligation to contribute capital or pay carried or other costs associated with the joint development agreement. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint development agreements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint development partners may share certain approval rights over major decisions;
- our joint development partners may not pay their share of the joint development agreement obligations, leaving us liable for their share of joint development liabilities;
- we may incur liabilities as a result of an action taken by our joint development partners;

- our joint development partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint development partners may result in delays, litigation or operational impasses.

The risks described above, the failure to continue our joint ventures or to resolve disagreements with our joint development partners could adversely affect our ability to transact the business of such joint development, which would in turn negatively affect our financial condition and results of operations.

The Jones family and Metalmark Capital, our primary private equity investor, control a significant percentage of Jones Energy, Inc.'s voting power and have the ability to take actions that may conflict with your interests.

As of December 31, 2014, the Jones family and Metalmark Capital held approximately 75.2% of the combined voting power of Jones Energy, Inc. Although the Jones family and Metalmark Capital are entitled to act separately in their own respective interests with respect to their ownership interests in Jones Energy, Inc., the Jones family and Metalmark Capital will have the ability to elect all of the members of our board of directors, and thereby control our management and affairs. In addition, the Jones family and Metalmark Capital have significant influence over all matters that require approval by our stockholders, including mergers and other material transactions.

The loss of senior management or technical personnel could adversely affect our operations.

Our success will depend to a large extent upon the efforts and abilities of our executive officers and key operations personnel. The loss of the services of one or more of these key employees could have a material adverse effect on us. We do not maintain insurance against the loss of any of these individuals. Our business will also be dependent upon our ability to attract and retain qualified personnel. Acquiring and keeping these personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud.

We have had limited accounting personnel to execute our accounting processes and limited other supervisory resources with which to address our internal control over financial reporting. As such, we have not maintained an effective control environment to ensure that the design and execution of our controls has consistently resulted in effective review of our financial statements and supervision by appropriate individuals. As a result of these factors, certain material misstatements in our annual financial statements were discovered and brought to the attention of our management by our independent registered public accounting firm for correction. These material misstatements included certain errors in our annual financial statements for the years ended 2010, 2011 and 2012, including out-of-period adjustments and errors in the calculation of our depreciation, depletion and amortization expense and our asset retirement obligations. Additionally, certain material misstatements were identified by the Company in the fourth quarter with respect to our financial statements for the interim periods ended March 31, 2014, June 30, 2014 and September 30, 2014 related to an error in the calculation of depletion, depreciation and amortization included in the Company's consolidated financial statements as reported in the Company's Quarterly Reports on Forms 10-Qs. See "Supplemental Quarterly Financial Information (Unaudited)" for restated financial information. This material weakness resulted in a misstatement of account balances that resulted in a material misstatement to the interim consolidated financial statements. We concluded that these control deficiencies constituted a material weakness in our control environment. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The control deficiencies described above, at varying degrees of severity, contributed to the material weakness in the control environment.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded company. To comply with the requirements of being a publicly traded company, we may need to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance, tax and legal staff. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 requires us, among other things, to annually review and report on the effectiveness of our internal controls over financial reporting. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. If one or more material weaknesses persist or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected. Ineffective internal controls could also subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business.

For as long as we are an emerging growth company, we will not be required to comply with certain requirements that apply to other public companies.

We continue to qualify as an "emerging growth company" under the Jumpstart Our Business Startups Act (the "JOBS Act"). By virtue of such, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 and reduced disclosure obligations regarding executive compensation in our periodic reports. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our Class A common stock held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation and process and record financial and operating data. As an oil and natural gas producer, we face various security threats, including cyber-security threats. Cyber-security attacks in particular are increasing and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although to date we have not experienced any material losses related to cyber-security attacks, we may suffer such losses in the future. Moreover, the various procedures and controls we use to monitor and protect against these threats and to mitigate our exposure to such threats may not be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, natural gas and NGLs and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may receive (or be deemed to receive), and the amounts of such payments could be significant.

We entered into the Tax Receivable Agreement with JEH and the pre-IPO owners. This agreement generally provides for the payment by us of 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) as a result of (i) the tax basis increases resulting from the pre-IPO owners' exchange of JEH Units for shares of Class A common stock (or resulting from a sale of JEH Units to us for cash) and (ii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of JEH. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. The term of the Tax Receivable Agreement will continue until all such tax benefits have been utilized or expired, unless we exercise our right to terminate the Tax Receivable Agreement by making the termination payment specified in the agreement.

The actual increase in tax basis, as well as the amount and timing of any payments under the Tax Receivable Agreement, will vary depending upon a number of factors, including the timing of the exchanges of JEH Units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the Tax Receivable Agreement constituting imputed interest or depletable, depreciable or amortizable basis. We expect that the payments that we will be required to make under the Tax Receivable Agreement could be substantial.

The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in either JEH or us.

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

If we elect to terminate the Tax Receivable Agreement early or it is terminated early due to certain mergers or other changes of control, we would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the Tax Receivable Agreement, which calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including the assumption that we have sufficient taxable income to fully utilize such benefits and that any JEH Units that the pre-IPO Owners or their permitted transferees own on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of such future benefits. In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction cost a potential acquirer may attribute to satisfying such obligations.

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that we will determine. The holders of rights under the Tax Receivable Agreement will not reimburse us for any payments previously made under the Tax Receivable Agreement if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any pre-IPO Owner will be netted against payments otherwise to be made, if any, to such pre-IPO owner after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

We are from time to time subject to, and are presently involved in, litigation or other legal proceedings arising out of the ordinary course of business. None of these legal proceedings are expected to have a material adverse effect on our financial condition, results of operations or cash flow. With respect to these proceedings, our management believes that we will either prevail, have adequate insurance coverage or have established appropriate reserves to cover potential liabilities. Any costs that management estimates may be paid related to these proceedings or claims are accrued when the liability is considered probable and the amount can be reasonably estimated. There can be no assurance, however, as to the ultimate outcome of any of these matters, and if all or substantially all of these legal proceedings were to be determined adversely to us, there could be a material adverse effect on our financial condition, results of operations and cash flow.

Items 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "JONE."

The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE for the periods indicated.

	2014		2013	
	High	Low	High	Low
1st Quarter	$18.32	$13.05	—	—
2nd Quarter	$20.57	$14.50	—	—
3rd Quarter(1)	$20.79	$17.26	$17.10	$13.60
4th Quarter	$18.82	$ 9.50	$18.14	$13.15

(1) For the third quarter of 2013, the data represents the period from July 24, 2013, the date on which our common stock began trading on the NYSE, through September 30, 2013.

On February 27, 2015, the last sale price of our common stock, as reported on the NYSE, was $8.54 per share. As of February 27, 2015, there were 25,208,402 shares of Class A common stock outstanding held by approximately five stockholders of record and 36,422,660 shares of Class B common stock outstanding held by approximately eleven stockholders of record.

Dividend Policy

We have not paid any dividends and do not anticipate declaring or paying any cash dividends to holders of our Class A common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, our senior secured revolving credit facility and the 2022 Notes prohibit us from paying dividends.

Issuer Purchases of Equity Securities

None.

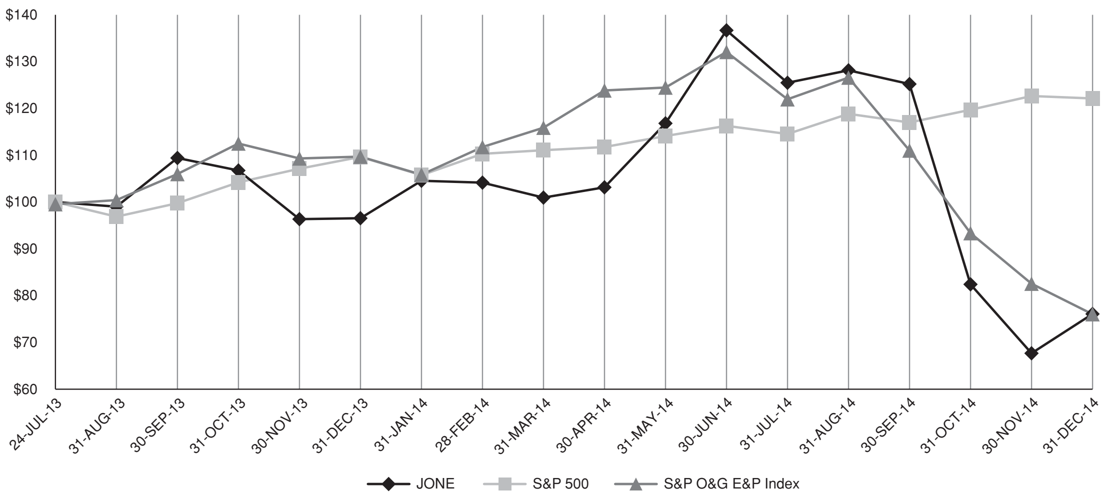
Sales of Unregistered Equity Securities

None.

Stock Performance Graph

The following stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the "Securities Act"), or the Securities Exchange Act of 1934, as amended (the "Exchange Act"), except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph compares the cumulative total shareholder return to Jones Energy, Inc.'s common stockholders as compared to the cumulative total returns on the Standard & Poor's 500 index ("the S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P 500 O&G E&P Index") since the time of our IPO. The graph was prepared assuming $100 was invested in our common stock at its initial public offering price of $15.00 per share and invested in the S&P 500 Index and the S&P 500 O&G E&P Index on July 24, 2013 at the closing price on such date and tracked through December 31, 2014.



Securities Authorized for issuance Under Equity Compensation Plans

The following table presents the securities authorized for issuance under the Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP") as of December 31, 2014.

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ($)	Number of Shares Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plan approved by security holders(1)	—	—	3,276,679(2)
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	3,276,679

(1) Our 2013 Omnibus Incentive Plan (the "LTIP") was approved by our board of directors in July 2013 and took effect on July 29, 2013. The LTIP was also approved by our shareholders at the Annual Meeting of Shareholders on July 10, 2013.

(2) The LTIP may consist of the following components: restricted stock, stock options, performance awards, restricted stock units, bonus stock awards, stock appreciation rights, cash awards, dividend equivalents, and other share-based awards. The LTIP limits the number of shares that may be delivered pursuant to awards to 3,850,000 shares of our Class A common stock. Our board of directors has approved total cumulative awards of 573,321 shares of restricted Class A common stock under the LTIP as of December 31, 2014.

Item 6. Selected Financial Data

The following table sets forth selected financial data of Jones Energy, Inc. and its predecessor for the years ended December 31, 2014, 2013, 2012, 2011 and 2010. This information should be read in connection with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" presented elsewhere in this report.

	Year Ended December 31,				
(in thousands except per share data)	**2014**	**2013**	**2012**	**2011**	**2010**
Operating revenues					
Oil and gas sales	$378,401	$258,063	$148,967	$167,261	$ 97,523
Other revenues	2,196	1,106	847	1,022	933
Total operating revenues	380,597	259,169	149,814	168,283	98,456
Operating costs and expenses					
Lease operating	43,843	27,781	23,097	21,548	16,296
Production taxes	18,094	12,865	5,583	5,333	2,206
Exploration	3,453	1,710	356	780	4,208
Depletion, depreciation and amortization	181,669	114,136	80,709	68,906	48,008
Impairment of oil and gas properties	—	14,415	18,821	31,970	10,727
Accretion of discount	770	608	533	413	490
General and administrative (including non-cash compensation expense)	25,763	31,902	15,875	16,679	11,423
Total operating expenses	273,592	203,417	144,974	145,629	93,358
Operating income	107,005	55,752	4,840	22,654	5,098
Other income (expense)					
Interest expense	(46,726)	(30,774)	(25,292)	(21,994)	(12,575)
Net gain (loss) on commodity derivatives	189,641	(2,566)	16,684	34,490	23,758
Gain on bargain purchase	—	—	—	26,208	—
Gain (loss) on sales of assets	297	(78)	1,162	(859)	8,644
Other income (expense), net	143,212	(33,418)	(7,446)	37,845	19,827
Income (loss) before income tax	250,217	22,334	(2,606)	60,499	24,925
Income tax provision					
Current	53	85	—	—	—
Deferred	26,021	(156)	473	173	145
Total income tax provision	26,074	(71)	473	173	145
Net income (loss)	224,143	22,405	(3,079)	60,326	24,780
Net income attributable to non-controlling interests	183,275	24,591	—	—	—
Net income (loss) attributable to controlling interests	$ 40,868	$ (2,186)	$ (3,079)	$ 60,326	$ 24,780
Earnings per share:					
Basic	$ 3.26	$ (0.17)			
Diluted	$ 3.26	$ (0.17)			
Weighted average shares outstanding:					
Basic	12,526	12,500			
Diluted	12,535	12,500			
Other Supplementary Data:					
EBITDAX(1)	$301,393	$204,997	$135,741	$127,960	$ 74,771
Adjusted net income(2)	64,205	54,792	29,411	34,894	17,599

(1) EBITDAX is a non-GAAP financial measure. For a definition of EBITDAX and a reconciliation of EBITDAX to our net income, see "—Non-GAAP Financial Measures" below.

(2) Adjusted net income is a non-GAAP financial measure. For a definition of adjusted net income and a reconciliation of adjusted net income to our net income, see "—Non-GAAP Financial Measures" below.

	Year Ended December 31,				
(in thousands of dollars)	2014	2013	2012	2011	2010
Statement of Cash Flow Data					
Net cash flow provided by operating activities	$ 265,423	$ 148,573	$ 84,550	$ 120,217	$ 44,624
Net cash used in investing activities	(463,903)	(368,277)	(337,636)	(318,963)	(90,785)
Net cash provided by financing activities	188,226	219,798	270,676	186,322	49,200
Net increase (decrease) in cash	$ (10,254)	$ 94	$ 17,590	$ (12,424)	$ 3,039

	As of December 31,				
(in thousands of dollars)	2014	2013	2012	2011	2010
Balance Sheet Data					
Cash and cash equivalents	$ 13,566	$ 23,820	$ 23,726	$ 6,136	$ 18,560
Other current assets	229,176	121,782	74,886	88,546	49,742
Total current assets	242,742	145,602	98,612	94,682	68,302
Property and equipment, net	1,642,908	1,300,672	1,010,742	743,575	495,613
Other long-term assets	107,578	41,705	41,332	42,878	21,379
Total assets	$1,993,228	$1,487,979	$1,150,686	$881,135	$585,294
Current liabilities	$ 229,999	$ 179,668	$ 93,421	$108,494	$ 60,938
Long-term debt	860,000	658,000	610,000	415,000	225,000
Other long-term liabilities	51,356	26,187	18,865	11,733	14,907
Total stockholders' / members' equity	851,873	624,124	428,400	345,908	284,449
Total liabilities and stockholders' / members' equity	$1,993,228	$1,487,979	$1,150,686	$881,135	$585,294

Non-GAAP financial measures

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, gains and losses from derivatives less the current period settlements of matured derivative contracts and the other items described below. EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP. 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. 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:

	Year Ended December 31,				
(in thousands of dollars)	2014	2013	2012	2011	2010
Reconciliation of EBITDAX to net income					
Net income (loss)	$ 224,143	$ 22,405	$ (3,079)	$ 60,326	$ 24,780
Interest expense (excluding amortization of deferred financing costs)	39,848	28,097	21,748	19,054	10,610
Exploration expense	3,453	1,710	356	780	4,208
Income taxes	26,074	(71)	473	173	145
Amortization of deferred financing costs	6,878	2,677	3,544	2,940	1,965
Depreciation and depletion	181,669	114,136	80,709	68,906	48,008
Impairment of oil and natural gas properties	—	14,415	18,821	31,970	10,727
Accretion expense	770	608	533	413	490
Other non-cash charges	376	79	129	(59)	390
Stock compensation expense	4,040	10,838	570	1,134	—
Other compensation expense	758	2,719	—	—	—
Net (gain) loss on derivative contracts	(189,641)	2,566	(16,684)	(34,490)	(23,758)
Current period settlements of matured derivative contracts	4,476	5,209	29,783	2,162	5,850
Amortization of deferred revenue	(1,154)	(469)	—	—	—
Gain on bargain purchase	—	—	—	(26,208)	—
Loss (gain) on sales of assets	(297)	78	(1,162)	859	(8,644)
EBITDAX	$ 301,393	$204,997	$135,741	$127,960	$ 74,771

Adjusted Net Income and Adjusted Earnings per Share are supplemental non-GAAP financial measures that are used by management and external users of the Company's consolidated financial statements. We define Adjusted Net Income as net income excluding the impact of certain non-cash items including gains or losses on commodity derivative instruments not yet settled, impairment of oil and gas properties, non-cash compensation expense, and the gain on bargain purchase associated with the Southridge acquisition in 2011. We define Adjusted Earnings per Share as earnings per share plus that portion of the components of adjusted net income allocated to the controlling interests divided by weighted average shares outstanding. We believe adjusted net income and adjusted earnings per share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items for which the timing or amount cannot be reasonably determined. However, these measures are provided in addition to, not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Our computations of adjusted net income and adjusted earnings per share may not be comparable to other similarly titled measures of other companies.

The following table provides a reconciliation of net income (loss) as determined in accordance with GAAP to adjusted net income for the periods indicated.

(in thousands except per share data)	Year Ended December 31, 2014	2013	2012	2011	2010
Net income (loss)	$ 224,143	$ 22,405	$ (3,079)	$ 60,326	$ 24,780
Net (gain) loss on derivative contracts	(189,641)	2,566	(16,684)	(34,490)	(23,758)
Current period settlements of matured derivative contracts	4,476	5,209	29,783	2,162	5,850
Impairment of oil and gas properties	—	14,415	18,821	31,970	10,727
Non-cash stock compensation expense	4,040	10,838	570	1,134	—
Other non-cash compensation expense	758	2,719	—	—	—
Gain on bargain purchase	—	—	—	(26,208)	—
Net unamortized capitalized loan costs	3,761	—	—	—	—
Tax impact(1)	16,668	(3,360)	—	—	—
Adjusted net income	$ 64,205	$ 54,792	$ 29,411	$ 34,894	$ 17,599
Adjusted net income attributable to non-controlling interests	52,423	51,182			
Adjusted net income attributable to controlling interests	$ 11,782	$ 3,610			
Earnings per share (basic)	$ 3.26	$ (0.17)			
Net (gain) loss on derivative contracts	(3.85)	0.43			
Current period settlements of matured derivative contracts	0.09	(0.01)			
Impairment of oil and gas properties	—	0.29			
Non-cash stock compensation expense	0.08	0.02			
Other non-cash compensation expense	0.02	—			
Net unamortized capitalized loan costs	0.08	—			
Tax impact	1.26	(0.27)			
Adjusted earnings per share (basic)	$ 0.94	$ 0.29			
Earnings per share (diluted)	$ 3.26	$ (0.17)			
Net (gain) loss on derivative contracts	(3.85)	0.43			
Current period settlements of matured derivative contracts	0.09	(0.01)			
Impairment of oil and gas properties	—	0.29			
Non-cash stock compensation expense	0.08	0.02			
Other non-cash compensation expense	0.02	—			
Net unamortized capitalized loan costs	0.08	—			
Tax impact	1.26	(0.27)			
Adjusted earnings per share (diluted)	$ 0.94	$ 0.29			
Effective tax rate on net income attributable to controlling interests	35.7%	36.9%			

(1) In arriving at adjusted net income, the tax impact of the adjustments to net income is determined by applying the appropriate tax rate to each adjustment and then allocating the tax impact between the controlling and non-controlling interests.

Item 7. 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 our Consolidated Financial Statements and the Notes to Consolidated Financial Statements appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that are based on management's current expectations, estimates and projections about our business and operations, and that involve risks and uncertainties. Our actual results may differ materially from those currently anticipated and expressed in such forward-looking statements as a result of a number of factors, including those we discuss under "Risk Factors," "Cautionary Statement Regarding Forward-Looking Statements" and elsewhere in this report.

Overview

Jones Energy, Inc. is an independent oil and gas company engaged in the exploration, development, production and acquisition of oil and natural gas properties focused in the Anadarko and Arkoma basins of Texas and Oklahoma. We have drilled over 775 total wells, including over 590 horizontal wells, since our 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.

As of December 31, 2014, our total estimated proved reserves were 115.3 MMBoe, of which 52% were classified as proved developed reserves. Approximately 24% of our total estimated proved reserves as of December 31, 2014 consisted of oil, 34% consisted of NGLs, and 42% consisted of natural gas.

Outlook

We have identified 2,765 gross drilling locations in our areas of operation, which gives us many years of development drilling. In the second half of 2014, prices for oil, NGLs and natural gas declined rapidly, with oil and NGL prices hitting a 6-year low and natural gas prices hitting a 3-year low. We believe that the commodity pricing environment will remain challenging for 2015. However, we believe that our ability to reduce drilling and completion costs, our existing drilling inventory, and our strong hedge position will enable us to generate attractive economic rates of return and to compete for strategic acquisitions and joint development opportunities.

Our 2014 capital expenditures totaled $524 million, of which $468 million was utilized to drill and complete wells. We currently plan to invest approximately $210 million in total capital expenditures in 2015, including approximately $190 million for drilling and completion, and $20 million for workovers and efficiency projects. Please see "Liquidity and Capital Resources." Assuming current market conditions and drilling success rates comparable to our historical performance, we believe we will be able to fund all of our 2015 budgeted capital expenditures with our cash flow from operations and projected availability under our senior secured revolving credit facility.

Our 2015 capital budget assumes a three rig program in the Cleveland during the first quarter, and, assuming additional drilling and completion cost reductions can be achieved, two additional rigs being added during the second quarter, resulting in a five rig program in the Cleveland in the second half of 2015. We have allocated our 2015 capital expenditure budget as follows:

	2015 Capital Expenditure Budget
	(in millions)
Drilling and completion:	
Cleveland	$190
Other activities	20
All properties and activities	$210

Although we reduced our year end 2014 rig count in early 2015, we believe a reasonable rig schedule will allow us to develop all drilling locations classified as proved undeveloped reserves in the year-end reserve report within five years.

NGLs are made up of ethane, propane, isobutane, butane and natural gasoline, all of which have different uses and different pricing characteristics. Realized monthly pricing for NGLs, which comprised 28% of our 2014 and 2013 production, has recently hit a six-year low, principally due to oversupply in the market. Under our sale contracts in the Anadarko basin, we are generally paid market rates for the NGLs we produce, so the lower pricing has resulted in lower NGL revenues. A further or extended decline in NGL prices, or in oil or natural gas prices, could materially and adversely affect our financial position, our results of operations, the quantities of hydrocarbon reserves that we can economically produce and our access to capital.

Basis of Presentation

We consider and report all of our operations as one segment.

Sources of our revenues

We derive our revenue from the production and sale of oil, natural gas and NGLs. Our revenues are a function of oil, natural gas, and NGL production volumes sold and average sales prices received for those volumes. We recognize revenues when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured and evidenced by a contract. Our revenues do not include the effects of our hedging activities and may vary substantially from period to period as a result of changes in production volumes or commodity prices.

Hedging

Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a significant portion of our anticipated oil, natural gas and NGL production. These instruments allow us to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The instruments provide only partial protection against declines in oil and gas prices, and may limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge physical production by individual hydrocarbon product in order to protect returns. The only counterparties to our derivatives are lenders under the Revolver, and our hedge positions are generally reviewed on a monthly basis. This eliminates potential margin calls in execution and limits our credit exposure to these particular lenders. We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in net income. We record such derivative instruments as assets or liabilities in the balance sheet. During the year ended December 31, 2014, 78% of our total production for oil, natural gas and NGLs was hedged. As of December 31, 2014, approximately 50% of our total forecasted production from proved reserves through 2016 was hedged, and the market value of our hedge position was $209 million. We do not anticipate any substantial changes in our hedging policy.

Our open positions as of December 31, 2014 were as follows:

	Year Ending December 31,				
	2015	2016	2017	2018	2019
Oil positions(1):					
Swaps:					
Hedged volume (MBbl)	2,322	1,809	769	581	—
Weighted average price ($/Bbl)	$ 84.71	$ 83.81	$ 84.56	$82.75	—
Natural gas positions(2):					
Swaps:					
Hedged volume (MMcf)	19,543	16,230	11,660	8,980	—
Weighted average price ($/Mcf)	$ 4.47	$ 4.49	$ 4.35	$ 4.29	—
NGL positions(3):					
Swaps:					
Hedged volume (MBbl)	1,536	238	42	—	—
Weighted average price ($/gal)	$ 0.97	$ 1.19	$ 1.53	—	—
Natural Gas Basis positions(4):					
Swaps:					
Hedged volume (MMcf)	9,750	1,000	—	—	—
Weighted average price ($/Mcf)	$ (0.22)	$ (0.28)	—	—	—

(1) The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

(2) The natural gas derivatives are settled based on the NYMEX natural gas futures price for the calculation period.

(3) The NGL derivatives are settled based on the month's average daily price of Mont Belvieu and Conway ethane, propane, isobutane, butane and natural gasoline.

(4) The basis swap derivatives are settled based on the differential between the NYMEX natural gas futures price and the ANR Pipeline Co. Oklahoma price, the CenterPoint Energy Gas Transmission Co. East price, the Natural Gas Pipeline Co. of America Texok zone price, the Northern Natural Gas Co. demarcation price or the Panhandle Eastern Pipe Line Co. Texas/Oklahoma price.

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and gas properties. Lease operating expenses include both a portion of costs that are fixed in nature, such as infrastructure costs, as well as variable costs resulting from additional well maintenance and production enhancements. As production increases, our average lease operating expense per barrel of oil equivalent is typically reduced because fixed costs do not increase proportionately with production.

Exploration. Exploration expense consists of geological and geophysical costs, seismic costs, amortization of unproved leasehold costs, and the costs to drill exploratory wells that do not find proved reserves.

Depreciation, depletion and amortization. Under the successful efforts accounting method that we employ, we capitalize all costs associated with our acquisition, successful exploration, and all development efforts within cost centers classified by producing field. We then systematically expense the costs in each field on a units-of-production basis based on proved oil and natural gas reserve quantities. We calculate depletion on (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; and (ii) the estimated plugging and abandonment costs, net of estimated salvage values. We calculate depreciation on the cost of fixed assets related to our pipelines and other fixed assets over the estimated useful lives.

Impairment of oil and gas properties. This is the cost to reduce the carrying value of each field of proved oil and gas properties to no more than the fair value of the particular field for which impairment recognition is required and the cost to expense the remaining amount of the carrying value of each field of unproved oil and gas properties based on a periodic impairment assessment requiring significant judgment. We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage.

Accretion of discount. Accretion of discounts are related to our obligation for retirement of oil and gas wells and facilities. We record these liabilities when we place the assets in service, using discounted present values of the estimated future obligation. We then record accretion of the liabilities as they approach maturity.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other fees for professional services and legal compliance.

Interest and other. The primary component of this line item is the interest paid to lenders. We finance a portion of our working capital requirements and capital expenditures with borrowings under our senior secured revolving credit facility and senior notes. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. This classification also includes the amortization of capitalized loan acquisition costs and bank fees associated with the debt and commitment fees on undrawn portions of our revolving credit facilities.

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)	Years Ended December 31, 2014	2013	Change	Years Ended December 31, 2013	2012	Change
Revenues:						
Oil	$220,090	$145,146	$ 74,944	$145,146	$ 66,921	$ 78,225
Natural gas	82,947	55,511	27,436	55,511	30,503	25,008
NGLs	75,364	57,406	17,958	57,406	51,543	5,863
Total oil and gas	378,401	258,063	120,338	258,063	148,967	109,096
Other	2,196	1,106	1,090	1,106	847	259
Total operating revenues	380,597	259,169	121,428	259,169	149,814	109,355
Costs and expenses:						
Lease operating	43,843	27,781	16,062	27,781	23,097	4,684
Production taxes	18,094	12,865	5,229	12,865	5,583	7,282
Exploration	3,453	1,710	1,743	1,710	356	1,354
Depletion, depreciation and amortization	181,669	114,136	67,533	114,136	80,709	33,427
Impairment of oil and gas properties	—	14,415	(14,415)	14,415	18,821	(4,406)
Accretion of discount	770	608	162	608	533	75
General and administrative	25,763	31,902	(6,139)	31,902	15,875	16,027
Total costs and expenses	273,592	203,417	70,175	203,417	144,974	58,443
Operating income	107,005	55,752	51,253	55,752	4,840	50,912
Other income (expenses):						
Interest expense	(46,726)	(30,774)	(15,952)	(30,774)	(25,292)	(5,482)
Net gain (loss) on commodity derivatives	189,641	(2,566)	192,207	(2,566)	16,684	(19,250)
Gain (loss) on sales of assets	297	(78)	375	(78)	1,162	(1,240)
Total other income (expense)	143,212	(33,418)	176,630	(33,418)	(7,446)	(25,972)
Income (loss) before income tax	250,217	22,334	227,883	22,334	(2,606)	24,940
Income tax provision (benefit)	26,074	(71)	26,145	(71)	473	(544)
Net income (loss)	224,143	22,405	201,738	22,405	(3,079)	25,484
Net income attributable to non-controlling interests	183,275	24,591	158,684	24,591	—	24,591
Net income (loss) attributable to controlling interests	$ 40,868	$ (2,186)	$ 43,054	$ (2,186)	$ (3,079)	$ 893
Net production volumes:						
Oil (MBbls)	2,475	1,557	918	1,557	746	811
Natural gas (MMcf)	21,922	17,575	4,347	17,575	14,066	3,509
NGLs (MBbls)	2,345	1,724	621	1,724	1,773	(49)
Total (MBoe)	8,474	6,210	2,264	6,210	4,863	1,347
Average net (Boe/d)	23,216	17,014	6,202	17,014	13,287	3,727
Average sales price, unhedged:						
Oil (per Bbl), unhedged	$ 88.93	$ 93.22	$ (4.29)	$ 93.22	$ 89.71	$ 3.51
Natural gas (per Mcf), unhedged	3.78	3.16	0.62	3.16	2.17	0.99
NGLs (per Bbl), unhedged	32.14	33.30	(1.16)	33.30	29.07	4.23
Combined (per Boe) realized, unhedged	44.65	41.56	3.09	41.56	30.63	10.93
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 88.16	$ 87.86	$ 0.30	$ 87.86	$ 87.30	$ 0.56
Natural gas (per Mcf), hedged	4.02	3.93	0.09	3.93	3.76	0.17
NGLs (per Bbl), hedged	32.60	33.26	(0.66)	33.26	34.22	(0.96)
Combined (per Boe) realized, hedged	45.18	42.40	2.78	42.40	36.76	5.64
Average costs (per BOE):						
Lease operating	$ 5.17	$ 4.47	$ 0.70	$ 4.47	$ 4.75	$ (0.28)
Production taxes	2.14	2.07	0.07	2.07	1.15	0.92
Depletion, depreciation and amortization	21.44	18.38	3.06	18.38	16.60	1.78
General and administrative	3.04	5.14	(2.10)	5.14	3.26	1.88

Results of Operations—Year ended December 31, 2014 as compared to year ended December 31, 2013

Operating revenues

Oil and gas sales. Oil and gas sales increased by $120.3 million (46.6%) to $378.4 million for the year ended December 31, 2014, as compared to $258.1 million for the year ended December 31, 2013. The majority of the increase (67.8%) was due to higher crude oil production volumes with the remainder of the increase being primarily attributable to higher natural gas and natural gas liquid production volumes. Average daily production increased 36.5% to 23,216 Boe per day for the year ended December 31, 2014 as compared to 17,014 Boe per day for the year ended December 31, 2013. Crude oil production increased 59.0% from 1,557 MBbls for the year ended December 31, 2013 to 2,475 MBbls for the year ended December 31, 2014, primarily resulting from the wells acquired from Sabine at the end of 2013, combined with an increase in the number of wells drilled in 2014. Natural gas production increased 24.7% from 17,575 MMcf for the year ended December 31, 2013 to 21,922 MMcf for the year ended December 31, 2014, due to new wells added through drilling and the acquisition of the Sabine wells. The average realized oil price, excluding the effects of commodity derivative instruments, decreased from $93.22 per Bbl to $88.93 per Bbl, or 4.6%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $3.16 per Mcf to $3.78 per Mcf, or 19.6%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, decreased from $33.30 per Bbl to $32.14 per Bbl, or 3.5%, year over year.

Costs and expenses

Lease operating. Lease operating expense increased by $16.0 million (57.6%) to $43.8 million for the year ended December 31, 2014, as compared to $27.8 million for the year ended December 31, 2013. The increase occurred primarily in correlation with the 36.5% increase in production volumes. On a per unit basis, lease operating expense increased by $0.70 per Boe or 15.7%, from $4.47 to $5.17 per Boe, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. On an overall basis, lease operating expense increased due to new wells coming on line and higher compressor and salt water disposal expenses associated with the new wells drilled and acquired from Sabine.

Production taxes. Production taxes increased by $5.2 million (40.3%) to $18.1 million for the year ended December 31, 2014, as compared to $12.9 million for the year ended December 31, 2013. Overall production taxes increased in conjunction with the 46.6% increase in revenue. The average effective rate decreased from 5.0% for the year ended December 31, 2013 to 4.8% for the year ended December 31, 2014, primarily due to refunds of tax rebates recorded in 2014.

Exploration. Exploration expense increased from $1.7 million for the year ended December 31, 2013 to $3.5 million for the year ended December 31, 2014. The increase was related to dry hole costs in 2014 as the Company drilled an unsuccessful exploratory well.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $67.6 million (59.2%) to $181.7 million for the year ended December 31, 2014, as compared to $114.1 million for the year ended December 31, 2013. The increase was primarily the result of continued drilling activity and the acquisition of the Sabine wells at the end of 2013. On a per unit basis, depletion expense increased $3.06 per Boe or 16.6% to $21.44 per Boe for the year ended December 31, 2014 as compared to $18.38 per Boe for the year ended December 31, 2013. The per unit increase resulted from the higher cost to drill wells in 2014 compared to historical wells.

Impairment of oil and gas properties. We had no impairment charges on oil and gas properties for the year ended December 31, 2014 as compared to impairment charges of $14.4 million for the year ended December 31, 2013. In the fourth quarter of 2013, the Company recorded an impairment charge of $14.4 million related to its unproved Southridge properties. As the Company did not drill the required number of wells by October 31, 2013 necessary to keep its joint development agreement with Southridge in effect, the Company lost its right to drill the undeveloped acreage and associated unproved reserves. None of the 2013 charges were in the Cleveland formation.

General and administrative. General and administrative expenses decreased by $6.1 million (19.1%) to $25.8 million for the year ended December 31, 2014, as compared to $31.9 million for the year ended December 31, 2013. A decrease of $6.8 million related to stock compensation expense (of which $9.6 million related to the immediate vesting of certain shares on the IPO date in 2013, offset by $2.0 million of expense related to new incentive awards in 2014) and $2.4 million related to a one-time non-cash distribution in 2013 to management related to the Monarch incentive plan. Excluding these non-cash items, general and administrative expenses increased $2.7 million (14.7%) to $21.0 million for the year ended December 31, 2014, as compared to $18.3 million for the year ended December 31, 2013. The increase in cash general and administrative expense is attributable to an increase in personnel costs and office expense due to an increase in headcount to support our increased drilling activity. On a per unit basis, cash general and administrative expenses decreased from $2.95 per Boe for the year ended December 31, 2013 to $2.47 per Boe for the year ended December 31, 2014. The increase in activity resulting from drilling and the acquisition of the Sabine properties significantly increased production (36.5% on a Boe basis) but did not result in a proportional increase in general and administrative expenses.

Interest and other. Interest and other financing expenses increased by $15.9 million (51.6%) to $46.7 million for the year ended December 31, 2014, as compared to $30.8 million for the year ended December 31, 2013. Of the total expense, interest paid under our bank debt totaled $12.0 million and $26.3 million for the years ended December 31, 2014 and 2013, respectively. In July 2013, a majority of bank borrowing was paid down with the proceeds from the initial public offering. At the end of 2013, we increased our debt to fund the Sabine acquisition. On April 1, 2014 we issued $500 million senior notes at an interest rate of 6.75%. Proceeds from the notes were used to pay down the bank borrowings. Interest incurred on the senior notes amounted to $25.3 million during 2014. Our average debt outstanding for the year ended December 31, 2014 was $748.6 million as compared to $544.9 million for the year ended December 31, 2013, and the weighted average interest rate incurred on the outstanding borrowings was 4.98% and 4.82%, respectively.

Gain (loss) on commodity derivatives. We had a net gain on commodity derivatives of $189.6 million for the year ended December 31, 2014 as compared to a net loss of $2.6 million for the year ended December 31, 2013. The increase is attributable to decreases in crude oil prices year over year (crude oil prices averaged $93.00 during 2014 as compared to $97.97 during 2013), combined with decreases in future crude oil prices from 2013 to 2014. The 12-month forward prices at December 31, 2014 for crude oil averaged $59.11 per Bbl as compared to $91.70 per Bbl at December 31, 2013. Natural gas prices, however, increased, averaging $4.42 in 2014 as compared to $3.65 in 2013, partially offsetting the contraction in oil prices.

Gain (loss) on sales of assets. The gain (loss) on sales of assets was a gain of $0.3 million for the year ended December 31, 2014, compared to a loss of $0.1 million for the year ended December 31, 2013.

Income taxes. The provision for income taxes reflects our reorganization and recapitalization which occurred in connection with the Company's initial public offering. Following the IPO in July 2013, the Company is subject to federal and state income and franchise taxes, while only the Texas franchise tax applied to JEH prior to the IPO. Income tax expense was an expense of $26.1 million for the year ended December 31, 2014 compared to a benefit of $0.1 million for the year ended December 31, 2013. The non-controlling interest was allocated its proportionate share of the Texas franchise tax expense incurred during 2014 and 2013.

Results of Operations—Year ended December 31, 2013 as compared to year ended December 31, 2012

Operating revenues

Oil and gas sales. Oil and gas sales increased by $109.1 million (73.2%) to $258.1 million for the year ended December 31, 2013, as compared to $149.0 million for the year ended December 31, 2012. The majority of the increase (69.3%) 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 28.0% to 17,014 Boe per day for the year ended December 31, 2013 as compared to 13,287 Boe per day for the year ended December 31, 2012. Crude oil production increased 108.7% from 746 MBbls for the year ended December 31, 2012 to 1,557 MBbls for the year ended December 31, 2013, primarily resulting from the wells acquired from Chalker, which generally have an oil production rate that is higher than our average historical Cleveland wells, combined with an increase in the number of wells drilled in 2013. Natural gas production increased 24.9% from 14,066 MMcf for the year ended December 31, 2012 to 17,575 MMcf for the year ended December 31, 2013, due to new wells added through drilling and the Chalker acquisition. The average realized oil price, excluding the effects of commodity derivative instruments, increased from $89.71 per Bbl to $93.22 per Bbl, or 3.9%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $2.17 per Mcf to $3.16 per Mcf, or 45.6%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, increased from $29.07 per Bbl to $33.30 per Bbl, or 14.6%.

Costs and expenses

Lease operating. Lease operating expense increased by $4.7 million (20.3%) to $27.8 million for the year ended December 31, 2013, as compared to $23.1 million for the year ended December 31, 2012. The increase occurred in correlation with the 28.0% increase in production volumes. On a per unit basis, lease operating expense decreased by $0.28 per Boe or 5.9%, from $4.75 to $4.47 per Boe, for the year ended December 31, 2013 as compared to the year ended December 31, 2012. On an overall basis, lease operating expense increased due to new wells coming on line and higher compressor and salt water disposal expenses associated with the Chalker wells (as compared to our historical set of wells); however, on a per unit basis, lease operating expense decreased as the Chalker properties have an initial production rate that is higher than our average historical Cleveland well.

Production taxes. Production taxes increased by $7.3 million (130.4%) to $12.9 million for the year ended December 31, 2013, as compared to $5.6 million for the year ended December 31, 2012. Overall production taxes increased in conjunction with the 73.2% increase in revenue; however, the average effective rate increased from 3.7% for the year ended December 31, 2012 to 5.0% for the year ended December 31, 2013. Production taxes were at a higher rate during 2013 due to the acquisition and drilling of the Chalker properties in Texas, which imposes a higher initial tax rate (7.5%) than Oklahoma (1%), where many of our other properties are located.

Exploration. Exploration expense increased from $0.4 million for the year ended December 31, 2012 to $1.7 million for the year ended December 31, 2013. The increase was related to seismic expenses incurred in the Arkoma.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $33.4 million (41.4%) to $114.1 million for the year ended December 31, 2013, as compared to $80.7 million for the year ended December 31, 2012. The increase was primarily the result of continued drilling activity and the acquisition of the Chalker properties at the end of 2012. On a per unit basis, depletion expense increased $1.78 per Boe or 10.7% from $16.60 per Boe for the year ended December 31, 2012 as compared to $18.38 per Boe for the year ended December 31, 2013. The per unit increase resulted from the acquisition of the Chalker and Sabine properties, the write off of proved undeveloped reserves attributable to the Southridge joint development agreement, and the higher cost to drill wells in 2013 compared to historical wells. The write-off of the Southridge reserves will increase depletion expense per Boe, provided all other inputs are constant.

Impairment of oil and gas properties. We had impairment charges on oil and gas properties of $14.4 million for the year ended December 31, 2013 as compared to impairment charges of $18.8 million for the year ended December 31, 2012. In the fourth quarter of 2013, the Company recorded an impairment charge of $14.4 million related to its unproved Southridge properties. As the Company did not drill the required number of wells by October 31, 2013 necessary to keep its joint development agreement with Southridge in effect, the Company lost its right to drill the undeveloped acreage and associated unproved reserves. In 2012, all of the impairment charges related to inactive fields and minor plays, where the Company did not have any development. None of the 2013 charges were in the Cleveland formation.

General and administrative. General and administrative expenses increased by $16.0 million (100.6%) to $31.9 million for the year ended December 31, 2013, as compared to $15.9 million for the year ended December 31, 2012. Of this increase, $10.8 million related to stock compensation expense (of which $9.6 million was related to the immediate vesting of certain shares on the IPO date) and $2.7 million related to a one-time non-cash distribution to management related to the Monarch incentive plan. 2012 includes $0.6 million of stock compensation expense. Excluding these non-cash items, general and administrative expenses increased $3.0 million (19.6%) to $18.3 million for the year ended December 31, 2013, as compared to $15.3 million for the year ended December 31, 2012. The increase in cash general and administrative expense is attributable to an increase in salaries and benefits due to an increase in headcount to support our increased drilling activity, which was partially offset by an increase in overhead reimbursements, and an increase in professional fees incurred as a result of being a public company for a portion of 2013. On a per unit basis, cash general and administrative expenses decreased from $3.15 per Boe for the year ended December 31, 2012 to $2.95 per Boe for the year ended December 31, 2013. The increase in activity resulting from drilling and the acquisition of the Chalker properties significantly increased production (28.0% on a Boe basis) but did not result in a proportional increase in general and administrative expenses.

Interest and other. Interest and other financing expenses increased by $5.5 million (21.7%) to $30.8 million for the year ended December 31, 2013, as compared to $25.3 million for the year ended December 31, 2012. Of the total expense, interest paid under our bank debt totaled $26.3 million and $20.6 million for the years ended December 31, 2013 and 2012, respectively. We increased our debt at the end of 2012 to fund the Chalker acquisition. In July 2013, a majority of this was paid down with the proceeds from the initial public offering. At the end of 2013, we increased our debt again to fund the Sabine acquisition. Our average debt outstanding for the year ended December 31, 2013 was $544.9 million as compared to $428.1 million for the year ended December 31, 2012 and the weighted average interest rate incurred on the outstanding borrowings was 4.82% and 4.96%, respectively.

Gain (loss) on commodity derivatives. We had a net loss on commodity derivatives of $2.6 million for the year ended December 31, 2013 as compared to a net gain of $16.7 million for the year ended December 31, 2012. The decrease is attributable to increases in crude oil and natural gas prices year over year (crude oil prices averaged $97.97 during 2013 as compared to $94.20 during 2012 and natural gas prices averaged $3.65 in 2013 as compared to $2.79 in 2012) combined with increases in future crude oil prices from 2012 to 2013 as compared to decreases in future crude oil prices from 2012 to 2012. The 12-month forward prices at December 31, 2013 for crude oil averaged $95.66 per Bbl as compared to $93.09 per Bbl at December 31, 2012, while the 12-month forward prices at December 31, 2012 averaged $93.09 per Bbl as compared to $98.77 per Bbl at December 31, 2012.

Gain (loss) on sales of assets. The gain on sales of assets decreased from $1.2 million for the year ended December 31, 2012 to a loss of $0.1 million for the year ended December 31, 2013, due to the sale of properties in the North Barnett Shale during the first quarter of 2012 compared with no significant sales of properties in 2013.

Income taxes. The provision for income taxes calculated for 2013 reflects our reorganization and recapitalization which occurred in connection with the Company's initial public offering. Following the IPO, the Company is subject to federal and state income and franchise taxes, while only the Texas franchise tax applied to JEH prior to the IPO. The income tax expense decreased from $0.5 million for the year ended December 31, 2012 to a benefit of $0.1 million for the year ended December 31, 2013. The 2012 income tax expense solely reflected the Texas franchise tax liability for JEH. The 2013 income tax benefit included a benefit for federal income taxes reduced by the Texas franchise tax expense. The non-controlling interest was allocated its proportionate share of the Texas franchise tax expense incurred during 2013.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been private and public sales of our debt and equity, borrowings under bank credit facilities and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We strive to maintain financial flexibility in order to maintain substantial borrowing capacity under our Revolver (as defined below), facilitate drilling on our undeveloped acreage positions and permit us to selectively expand our acreage positions. Depending on the timing and concentration of the development of our non-proved locations, we may be required to generate or raise significant amounts of capital to develop all of our potential drilling locations should we endeavor to do so. 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. Our balance sheet at December 31, 2014 reflects a positive working capital balance largely due to the $112.7 million increase in current commodity derivative assets. We have historically and in the future expect to maintain a negative working capital balance, and we use our Revolver to help manage our working capital. Our borrowing base at December 31, 2014 was $625 million of which $360 million was utilized and $265 million was available.

Our 2015 capital budget will be primarily focused on the development of existing core areas in the Cleveland play through exploitation and development. The amount of capital we expend may fluctuate materially based on the market conditions for commodity prices and costs of drilling and completing wells, the economic returns being realized and the success of our drilling results as the year progresses. We expect to fund our entire 2015 capital budget with cash flows from operations and borrowings under our Revolver. If necessary, we may also access capital through proceeds from potential asset dispositions and the future issuance of debt and/or equity securities.

On February 17, 2015, we completed the issuance and sale of 7,500,000 shares of Class A common stock to the public at a price of $10.25 per share (the "Public Equity Offering"). On February 23, 2015, we completed the sale of an aggregate of $50 million of our Class A common stock and $250 million in aggregate principal amount of our 9.25% senior unsecured notes due 2023 to certain affiliates of GSO Capital Partners LP and Magnetar Capital LLC in a private placement (the "Private Placements"). The net proceeds of the Public Equity Offering and the Private Placements were primarily used to repay outstanding borrowings under our Revolver.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil and gas prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods in order to achieve the desired balance between sources and uses of liquidity and to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. For example, due to the steep reduction of commodity prices experienced in the fourth quarter of 2014, we reduced our capital budget for 2015 to $210 million. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

The following table summarizes our cash flows for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Net cash provided by operating activities	$ 265,423	$ 148,573	$ 84,550
Net cash used in investing activities	(463,903)	(368,277)	(337,636)
Net cash provided by financing activities	188,226	219,798	270,676
Net increase (decrease) in cash	$ (10,254)	$ 94	$ 17,590

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $265.4 million for the year ended December 31, 2014 as compared to cash provided by operating activities of $148.6 million for the year ended December 31, 2013. The increase in operating cash flows was primarily due to a $120.3 million increase in oil and gas revenues for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in revenue was primarily driven by a 59.0% increase in oil production volumes as a result of drilling and the acquisition of the Sabine wells in the fourth quarter of 2013, combined with increases in natural gas and NGL production volumes.

Net cash provided by operating activities was $148.6 million for the year ended December 31, 2013 as compared to cash provided by operating activities of $84.6 million for the year ended December 31, 2012. The increase in operating cash flows was primarily due to a $109.1 million increase in oil and gas revenues for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in revenue was primarily driven by a 108.7% increase in oil production volumes as a result of drilling and the acquisition of the Chalker wells in the fourth quarter of 2012, combined with increases in crude oil and natural gas volumes.

Our operating cash flows are sensitive to a number of variables, the most significant of which is oil, NGL, and natural gas prices. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Cash Flow Used in Investing Activities

Net cash used in investing activities was $463.9 million for the year ended December 31, 2014 as compared to cash used in investing activities of $368.3 million for the year ended December 31, 2013. The increase was primarily driven by higher capital expenditures which increased $277.0 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013 due to an increase in drilling activity. The increase in capital expenditures was partially offset by the absence of acquisitions of property during 2014 as compared to the $178.2 million acquisition of the Sabine properties at the end of 2013. $15.7 million was refunded in 2014 after determining the final purchase price of the Sabine properties that were acquired in 2013. Additionally, cash flows from current period settlements of our commodity derivative instruments were net payments of $3.7 million for the year ended December 31, 2014 as compared to net receipts of $7.6 million for the year ended December 31, 2013 as a result of higher commodity prices that occurred early in the year 2014.

Net cash used in investing activities was $368.3 million for the year ended December 31, 2013 as compared to cash used in investing activities of $337.6 million for the year ended December 31, 2012. The increase was primarily driven by higher capital expenditures which increased $117.5 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012 due to an increase in drilling activity. The increase in capital expenditures was partially offset by the decrease in acquisitions as the purchase price of the Sabine acquisition ($193.5 million) at the end of 2013 was less than that of the Chalker acquisition ($253.5 million) at the end of 2012. Additionally, cash flows from current period settlements of our commodity derivatives instruments decreased by $21.1 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012 as a result of an increase in crude oil and natural gas prices. Finally, we received cash proceeds of $9.2 million from the sale of North Barnett properties in the first quarter of 2012, and experienced no meaningful sales of properties during the year ended December 31, 2013.

We expect our 2015 capital expenditures to be approximately $210.0 million, which is a 59.9% decrease from the $523.6 million incurred for 2014. Expenditures for development and exploration of oil and gas properties are the primary use of our capital resources. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, the degree of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities was $188.2 million for the year ended December 31, 2014 as compared to net cash provided by financing activities of $219.8 million for the year ended December 31, 2013. The decrease in cash flows provided by financing activities was primarily due to net payment on our credit facility of $311.4 million during 2014 as compared to net borrowing of $47.3 million during 2013. The net proceeds from the issuance of our senior notes of $490.0 million (net of expenses) in the second quarter of 2014 were used to repay borrowings under the credit facilities of $468 million during the year ended December 31, 2014.

Net cash provided by financing activities was $219.8 million for the year ended December 31, 2013 as compared to net cash provided by financing activities of $270.7 million for the year ended December 31, 2012. The decrease in cash flows provided by financing activities was primarily due to net borrowings of $47.3 million during 2013 as compared to $185.7 million during 2012. The net proceeds from the initial public offering of our Class A common stock of $172.5 million (net of expenses) in the third quarter of 2013 were used to repay debt of $167.0 million during the year ended December 31, 2013.

Senior Notes due 2022

On April 1, 2014, JEH and its wholly-owned subsidiary, Jones Energy Finance Corp. (together the "Issuers"), sold $500.0 million in aggregate principal amount of the Issuers' 6.75% Senior Notes due 2022 (the "2022 Notes"). We used the net proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan (as defined below) ($160.0 million) and a portion of the borrowings under the Revolver ($308.0 million). We subsequently terminated the Term Loan in accordance with its terms. The 2022 Notes bear interest at a rate of 6.75% per year, payable semi-annually on April 1 and October 1 of each year beginning October 1, 2014. As of December 31, 2014, we had $8.4 million in interest accrued related to the 2022 Notes.

The 2022 Notes are guaranteed on a senior unsecured basis by us and by all of our existing significant subsidiaries. The 2022 Notes will be senior in right of payment to any future subordinated indebtedness of the Issuers.

We may redeem the 2022 Notes at any time on or after April 1, 2017 at a declining redemption price set forth in the indenture, plus accrued and unpaid interest.

The indenture governing the 2022 Notes contains covenants that, among other things, limit our ability to incur additional indebtedness or issue certain preferred stock, pay dividends on capital stock, transfer or sell assets, make investments, create certain liens, enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us, consolidate, merge or transfer all of our assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the 2022 Notes are rated investment grade by Standard & Poor's or Moody's.

Senior Notes due 2023

On February 23, 2015, the Issuers sold $250.0 million in aggregate principal amount of the Issuers' 9.25% Senior Notes due 2023 (the "2023 Notes"). We used the net proceeds from the issuance of the 2023 Notes to repay outstanding borrowings under the Revolver. The 2023 Notes bear interest at a rate of 9.25% per year, payable semi-annually on March 15 and September 15 of each year beginning September 15, 2015.

The 2023 Notes are guaranteed on a senior unsecured basis by us and by all of our existing significant subsidiaries. The 2023 Notes will be senior in right of payment to any future subordinated indebtedness of the Issuers.

We may redeem the 2023 Notes at any time on or after March 15, 2018 at a declining redemption price set forth in the indenture, plus accrued and unpaid interest.

The indenture governing the 2023 Notes contains covenants that, among other things, limit our ability to incur additional indebtedness or issue certain preferred stock, pay dividends on capital stock, transfer or sell assets, make investments, create certain liens, enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us, consolidate, merge or transfer all of our assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the 2023 Notes are rated as investment grade by Standard & Poor's or Moody's.

Credit Facilities

Senior Secured Revolving Credit Facility. JEH has a $1 billion senior secured revolving credit facility (the "Revolver") with Wells Fargo Bank, N.A. as the administrative agent, and a syndicate of lenders. Availability under the Revolver is subject to a borrowing base, which is currently $562.5 million following the issuance of the 2023 Notes. The Revolver matures in November 2019. As of December 31, 2014, JEH had borrowings of $360 million outstanding under the Revolver. The net proceeds from the February 2015 Public Equity Offering and Private Placements were used to repay outstanding borrowings under the Revolver. JEH's obligations under the Revolver are guaranteed by us and JEH's subsidiaries and are secured by substantially all of their assets (other than equity interests of JEH held by us).

On November 6, 2014, JEH entered into a ninth amendment (the "Ninth Amendment") to the Revolver. The Ninth Amendment amended the Revolver to, among other things, (1) increase the borrowing base under the Revolver from $550 million to $625 million, and (2) extend the maturity date of the Revolver to November 6, 2019. The foregoing description of the Ninth Amendment is not complete and is qualified by reference to the complete document, which was filed as Exhibit 10.1 to our third quarter 2014 Form 10-Q and is incorporated herein by reference.

The borrowing base under our Revolver will be redetermined at least semi-annually on or about April 1 and October 1 of each year. JEH and the administrative agent (acting at the direction of lenders holding at least 66⅔% of the outstanding loans) may each request one unscheduled borrowing base redetermination between each scheduled redetermination. In addition, the lenders may elect to redetermine the borrowing base upon the occurrence of certain defaults under our material operating agreements or upon the cancellation or termination of certain of our joint development agreements. The borrowing base may also be reduced as a result of our issuance of unsecured notes, our termination of material hedging positions or our consummation of significant asset sales.

If the aggregate outstanding principal amount of the revolving loans under the Revolver exceeds the borrowing base as a result of a scheduled or interim adjustment of the borrowing base, we must prepay revolving loans in an amount equal to such excess within 90 days following the date the adjustment occurs or the date we receive notice thereof (with at least one-half of the prepayment to be paid or deposited within 45 days following such date). However, if such a borrowing base deficiency results from a permitted disposition of oil and gas properties or from terminations or modifications of hedge positions, we must immediately make such prepayment and/or deposit of cash collateral. Otherwise, all unpaid principal and interest is due at maturity.

Interest on loans under our Revolver is calculated, at JEH's option, at either (i) the LIBO Rate for the applicable interest period plus a margin ranging from 1.50% to 2.50% based on the level of borrowing base utilization at such time or (ii) the greatest of (x) the prime rate announced by Wells Fargo Bank, N.A. in effect on such day, (y) the federal funds rate plus 0.50% and (z) the one-month adjusted LIBO Rate plus 1.00%, plus a margin ranging from 0.50% to 1.50% based on the level of borrowing base utilization at such time. JEH is also required to pay a quarterly commitment fee on the unused portion of the aggregate commitments of the lenders, at a rate per annum of either 0.375% or 0.50%, depending on our utilization of the borrowing base.

The Revolver contains various covenants that, among other things, limit our ability to:

- incur indebtedness;
- grant liens on our assets;
- pay dividends or distributions or redeem any of our equity interests;
- make certain investments, loans and advances;
- merge into or with or consolidate with any other person, or dispose of all or substantially all of our property to any other person;
- engage in certain asset dispositions;
- enter into transactions with affiliates;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- allow gas imbalances, take-or-pay or certain other prepayments with respect to oil and gas properties; and
- enter into certain derivative arrangements.

The Revolver also contains a covenant which restricts the ability of Jones Energy, Inc. to (i) hold any assets, (ii) incur, create, assume, or suffer to exist any debt or any other liability or obligation, (iii) create, make or enter into any investment or (iv) engage in any other activity or operation other than, among other exceptions described therein, its ownership of equity interests in JEH and the activities of a passive holding company and assets and operations incidental thereto (including the maintenance of cash and reserves for the payment of operational costs and expenses).

Jones Energy, Inc. and its consolidated subsidiaries are also required under the Revolver to maintain the following financial ratios:

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and
- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

We believe that we are in compliance with the terms of our Revolver. If an event of default exists under the Revolver, the lenders will be able to accelerate the obligations outstanding under the Revolver and exercise other rights and remedies. Our Revolver contains customary events of default, including the occurrence of a change of control, as defined in the Revolver.

Second Lien Term Loan Facility. In addition, prior to the issuance of the 2022 Notes JEH had a $160 million second lien term loan facility (the "Term Loan") with Wells Fargo Energy Capital, Inc., as the administrative agent, and a syndicate of lenders. All outstanding borrowings on the Term Loan were repaid using a portion of the proceeds obtained from issuing the 2022 Notes in the second quarter 2014. The Company subsequently terminated the Term Loan in accordance with its terms.

Off-Balance Sheet Arrangements

At December 31, 2014, we did not have any off-balance sheet arrangements.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2014:

	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter
	(dollars in thousands)				
Long-term debt obligations	$ 860,000	$ —	$ —	$360,000	$500,000
Interest expense	285,172	42,327	126,982	74,253	41,610
Drilling rig commitments	16,761	16,761	—	—	—
Well services commitments	4,900	4,900	—	—	—
Commodity derivative obligations	28	—	28		—
Operating lease obligations	5,536	944	3,093	1,499	—
Asset retirement obligations, discounted	13,610	3,074	572	524	9,440
Total	$1,186,007	$68,006	$130,675	$436,276	$551,050

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP. As used herein, the following acronyms have the following meanings: "FASB" means the Financial Accounting Standards Board; the "Codification" refers to the Accounting Standards Codification, the collected accounting and reporting guidance maintained by the FASB; "ASC" means Accounting Standards Codification and is generally followed by a number indicating a particular section of the Codification; and "ASU" means Accounting Standards

Update, followed by an identification number, which are the periodic updates made to the Codification by the FASB.

The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies.

Use of Estimates. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the amounts of revenues and expenses reported for the period then ended.

Reserves. Reserve estimates significantly impact depreciation and depletion expense and the calculation of potential impairments of oil and gas properties. Under the SEC rules, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

Reserves were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month within the twelve-month period ending on the date as of which the applicable estimate is presented. These prices were adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Periodic revisions to the estimated reserves and related future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, changes in oil and natural gas prices, cost changes, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Property and Equipment. Oil and gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, lease acquisition costs and all development costs, including unsuccessful development wells, are capitalized.

Unproved Properties—Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees and other similar costs related to activities in acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered or determined through analysis, at which time related costs are transferred to proved oil and gas properties.

Exploration Costs—Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, amortization of unproved leasehold costs, and lease rentals. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending determination of whether the well has discovered proved commercial reserves. If the exploratory well is determined to be unsuccessful, the cost of the well is transferred to expense.

Proved Oil and Gas Properties—Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil, gas and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, and service wells, including unsuccessful development wells, are capitalized.

Impairment—The capitalized costs of proved oil and gas properties are reviewed at least annually for impairment, whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset or asset group exceeds its fair market value and is not recoverable. The determination of recoverability is based on comparing the estimated undiscounted future net cash flows from a producing field to the carrying value of the assets. If the future undiscounted cash flows, based on estimates of anticipated production and future oil and natural gas prices and operating costs, are lower than the carrying cost, the carrying cost of the field assets is reduced to fair value. For our proved oil and gas properties, we estimate fair value by discounting the projected future cash flows at an appropriate risk-adjusted discount rate.

Unproved leasehold costs are assessed at least annually to determine whether they have been impaired. Individually significant properties are assessed for impairment on a property-by-property basis, while individually insignificant unproved leasehold costs may be assessed in the aggregate. If unproved leasehold costs are found to be impaired, an impairment allowance is provided and a loss is recognized in the statement of operations.

Depreciation, Depletion and Amortization—Depreciation, depletion and amortization, or DD&A, of capitalized costs of proved oil and gas properties is computed using the unit-of-production method based upon estimated proved reserves. Assets are grouped for DD&A purposes on the basis of a reasonable aggregation of properties producing from or expected to be developed in a basin or formation. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves.

Sales—Sales of significant portions of a proved field are charged to income as incurred. Gain or loss on the sale is recognized to the extent of the difference between the net proceeds received and the remaining carrying value of the properties sold. Proceeds from the sale of insignificant portions of a larger proved field are accounted for as a recovery of costs, thereby reducing the carrying value of the field until such value reaches zero. For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Revenue Recognition. We recognize oil, natural gas and NGL revenues when products are delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured (sales method). Oil and natural gas sold is not significantly different from our share of production.

Derivative Financial Instruments. We use derivative contracts to hedge the effects of fluctuations in the prices of oil, natural gas and NGLs. We record such derivative instruments as assets or liabilities in the balance sheet (see Note 4, "Fair Value Measurement," in the Notes to Consolidated Financial Statements for further information on fair value). Estimating the fair value of derivative financial instruments requires management to make estimates and judgments regarding volatility and counterparty credit risk. We use net presentation of derivative assets and liabilities when such assets and liabilities are with the same counterparty and allowed under the ISDA trading agreement with such counterparty.

We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in net income in the period of the change as "Net gain (loss) on commodity derivatives."

Share-Based Compensation. We measure and record compensation expense for all share-based payment awards to employees and directors based on estimated grant-date fair values. Compensation costs for share-based awards are recognized over the requisite service period based on the grant-date fair value. Prior to our IPO, we were not publicly traded, and did not have a listed price with which to calculate fair value. We have historically and consistently calculated fair value using combined valuation models including an enterprise valuation approach; an income approach, utilizing future discounted and undiscounted cash flows; and a market approach, taking into consideration peer group analysis of publicly traded companies, and when available, actual cash transactions in our common stock.

Acquisitions. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in our statement of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities, if any, based on their estimated fair value at the time of the acquisition. We have historically and consistently calculated fair value using combined valuation models including an enterprise valuation approach; an income approach, utilizing future discounted and undiscounted cash flows; and a market approach, taking into consideration peer group analysis of publicly traded companies.

Asset Retirement Obligations. We recognize as a liability an asset retirement obligation, or ARO, associated with the retirement of a tangible long-lived asset in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. We measure the fair value of the ARO using expected future cash outflows for abandonment discounted generally at our cost of capital at the time of recognition.

Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued *Accounting Standards Update* ("ASU") No. 2014-09, "*Revenue from Contracts with Customers*," which creates a new topic in the Accounting Standards Codification ("ASC"), topic 606, "*Revenue from Contracts with Customers*." This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2016 and may be applied on either a full or modified retrospective basis. Early adoption is not permitted. We do not expect the adoption of these provisions to have a significant impact on the Company's consolidated financial statements. However, we will continue to assess the anticipated impact as further implementation guidance is released from the FASB.

In August 2014, the FASB issued ASU No. 2014-15, "*Presentation of Financial Statements—Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*." This ASU requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a "going concern" and to provide disclosures when certain criteria are met. Substantial doubt exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued (or available to be issued). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early adoption is permitted. We do not expect the adoption of these disclosures to have a significant impact on the Company's consolidated financial statements.

In January 2015, the FASB issued Accounting Standards Update No. 2015-01, *Income Statement—Extraordinary and Unusual Items* ("ASU 2015-01"). ASU 2015-01 removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed. ASU 2015-01 is effective for interim and annual reporting periods beginning after December 15, 2015. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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 December 31, 2014 was a net asset of $208.5 million.

As of December 31, 2014, we have hedged approximately 50% of our total forecasted production from proved reserves through December 31, 2016. For information regarding the terms of these hedges, please see "—Basis of presentation—Hedging" above. The production hedged thereby is consistent with the anticipated monthly production levels in the December 31, 2014 reserve report prepared by Cawley Gillespie, which is based on prices, costs and other assumptions required by SEC rules. Our actual production will vary from the amounts estimated in this reserve report, perhaps materially. Please read "Risk factors—Our estimated oil and natural gas reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves."

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 variable rate indebtedness. The terms of the senior secured revolving credit facility provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 0.50% to 2.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. The base rate margins under the terminated term loan were 6.0-7.0% depending on the base rate used and the amount of the loan outstanding. The terms of our senior notes provide for a fixed interest rate through their respective maturity dates. During the year ended December 31, 2014, borrowings under the Revolver, the second lien term loan and the 2022 Notes bore interest at a weighted average rate of 2.51%, 9.13% and 6.75%, respectively.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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.

Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were not effective as of December 31, 2014 because of the material weakness in internal control over financial reporting described below.

Management's Assessment of Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed under the supervision of our principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2014, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework (2013)*. Based on this assessment, management determined that, as of December 31, 2014, a material weakness related to design and execution of our controls continued to exist. Additionally, this material weakness could result in a misstatement of account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Because of this material weakness, management concluded that we did not maintain effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

The material weakness resulted in an adjustment identified by the Company in the fourth quarter with respect to the consolidated financial statements for the interim periods ended March 31, 2014, June 30, 2014 and September 30, 2014 related to an error in the calculation of depletion, depreciation and amortization included in the Company's consolidated financial statements as reported in the Company's Quarterly Reports on Forms 10-Q. This material weakness resulted in a misstatement of account balances that resulted in a material misstatement to the interim consolidated financial statements.

Attestation Report of the Registered Public Accounting Firm

Pursuant to 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.

Remediation steps to address the material weakness

The material weakness in our internal control over financial reporting described above was previously disclosed in Item 9A, *Controls and Procedures* of our Annual Report on Form 10-K for the year ended December 31, 2013.

Management took steps during the year ended December 31, 2014 to address the previously identified material weakness, 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. We have strengthened our internal control environment through the addition of skilled accounting personnel. This team has enabled us to expedite our month-end close process, thereby facilitating the timely preparation of financial reports. 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.

In addition to the improvements in staffing discussed above, we have designed and implemented new accounting processes and control procedures specifically related to those areas with adjustments identified in prior and current years. These procedures and controls, in conjunction with the staffing improvements, made progress toward remediation of the previously noted material weakness. Specifically, during the year-end review process, one of our annual controls over depletion, depreciation, and amortization identified the adjustment discussed above. Going forward, the Company intends to implement a quarterly control to address the risk that resulted in the misstatement. Management will continue to evaluate the accounting process and related controls in order to address the risk of future misstatements.

Shortly after the initial public offering, the Company engaged an independent accounting and consulting firm to fulfill its internal audit needs. The principal focus of the internal audit function has been to test the design and operating effectiveness of our controls. Based upon our testing and evaluation of the effectiveness of our internal controls, we have concluded we have designed but not fully implemented new processes and controls to remediate the material weakness identified as of December 31, 2014.

Changes in Internal Control over Financial Reporting

As described above under Remediation Steps to address the material weakness, there were changes in our internal control over financial reporting, relating to the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11. Executive Compensation

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report or incorporated by reference:

(1) ***Financial Statements.*** Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(2) ***Financial Statement Schedules***. All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) ***Exhibits***. The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K.

EXHIBIT INDEX

Exhibit No.	Description
2.1	Purchase and Sale Agreement by and between Chalker Energy Partners II, LLC, the listed participating owners and Jones Energy Holdings, LLC, dated November 28, 2012 (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 7, 2013).
2.2	Purchase and Sale Agreement by and between Sabine Mid- Continent LLC, as seller, and Jones Energy Holdings, LLC, as purchaser, dated as of November 22, 2013 (incorporated by reference to Exhibit 2.2 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
3.1	Amended and Restated Certificate of Incorporation of Jones Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on July 30, 2013).
3.2	Amended and Restated Bylaws of Jones Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on July 30, 2013).
4.1	Form of Class A common stock Certificate (incorporated by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 7, 2013).
4.2	Registration Rights and Stockholders Agreement, dated as of July 29, 2013 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on July 30, 2013).
4.3	Indenture, dated April 1, 2014, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on April 1, 2014).
4.4	Registration Rights Agreement, dated April 1, 2014, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Citigroup Global Markets Inc., as the sole representative of the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on April 1, 2014).
10.1	Third Amended and Restated Limited Liability Company Agreement of Jones Energy Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.2	Exchange Agreement, dated as of July 29, 2013, by and among Jones Energy, Inc., Jones Energy Holdings, LLC and the members of Jones Energy Holdings, LLC party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.3	Tax Receivable Agreement, dated as of July 29, 2013, by and among Jones Energy, Inc., Jones Energy Holdings, LLC and the members of Jones Energy Holdings, LLC party thereto (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.4†	Jones Energy, Inc. 2014 Omnibus Incentive Plan, effective as of July 29, 2013 (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on July 30, 2013).

Exhibit No.	Description
10.5†	Jones Energy, Inc. Short Term Incentive Plan, effective as of July 29, 2013 (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.6†	Form of Director Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 4, 2013).
10.7†	Form of Employee Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 27, 2014).
10.8†	Form of Performance Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 27, 2014).
10.9†	Jones Energy, LLC Executive Deferral Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 23, 2013).
10.10†	Jones Energy Holdings, LLC Monarch Equity Plan (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.11	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 7, 2013).
10.12	Credit Agreement, dated as of December 31, 2009, among Jones Energy Holdings, LLC, as borrower, Wells Fargo Bank N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.13	Agreement and Amendment No. 1 to Credit Agreement (First Lien) (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.14	Master Assignment, Agreement and Amendment No. 2 to Credit Agreement (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.15	Master Assignment, Agreement and Amendment No. 3 to Credit Agreement (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.16	Agreement and Amendment No. 4 to Credit Agreement (First Lien) (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.17	Master Assignment, Agreement and Amendment No. 5 to Credit Agreement (incorporated by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.18	Waiver and Amendment No. 6 to Credit Agreement (incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).

Exhibit No.	Description
10.19	Waiver, Agreement and Amendment No. 7 to Credit Agreement and Amendment to Guarantee and Collateral Agreement (incorporated by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 17, 2013).
10.20	Borrowing Base Increase Agreement, dated as of December 18, 2013, among Jones Energy Holdings, LLC, as borrower, certain subsidiaries of Jones Energy Holdings, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
10.21	Agreement and Amendment No. 8 to Credit Agreement dated as of January 29, 2014, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
10.22	Master Assignment, Agreement and Amendment No. 9 to Credit Agreement dated as of November 6, 2014, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014).
10.23	Guarantee and Collateral Agreement, dated as of January 29, 2014, between Jones Energy, Inc., as guarantor, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
10.24	Second Lien Credit Agreement, dated as of December 31, 2009, among Jones Energy Holdings, LLC, as borrower, Wells Fargo Energy Capital, Inc., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.25	Agreement and Amendment No. 1 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.26	Agreement and Amendment No. 2 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.27	Agreement and Amendment No. 3 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.28	Agreement and Amendment No. 4 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.29	Agreement and Amendment No. 5 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).

Exhibit No.	Description
10.30	Waiver and Amendment No. 6 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.22 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.31	Waiver, Agreement and Amendment No. 7 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 17, 2013).
10.32	Firm Crude Oil Gathering and Transportation Agreement, dated September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014).
10.33	Gathering and Transportation Services Agreement, dated as of September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014).
21.1*	List of Subsidiaries of Jones Energy, Inc.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Cawley Gillespie & Associates, Inc.
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).
99.1*	Summary Report of Cawley, Gillespie & Associates, Inc. for reserves as of December 31, 2014
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

†—Management contract or compensatory plan or arrangement required to be filed as an exhibit to this 10-K pursuant to Item 15(b).

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: March 6, 2015

By: /s/ JONNY JONES

Name: Jonny Jones
Title: *Chief Executive Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated.

Name	Title	Date
/s/ JONNY JONES Jonny Jones	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	March 6, 2015
/s/ MIKE S. MCCONNELL Mike S. McConnell	Director and President	March 6, 2015
/s/ ROBERT J. BROOKS Robert J. Brooks	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	March 6, 2015
/s/ HOWARD I. HOFFEN Howard I. Hoffen	Director	March 6, 2015
/s/ GREGORY D. MYERS Gregory D. Myers	Director	March 6, 2015
/s/ HALBERT S. WASHBURN Halbert S. Washburn	Director	March 6, 2015
/s/ ALAN D. BELL Alan D. Bell	Director	March 6, 2015
/s/ ROBB L. VOYLES Robb L. Voyles	Director	March 6, 2015

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms and abbreviations defined in this section are used throughout this Annual Report on Form 10K:

"***AMI***"—Area of mutual interest, typically referring to a contractually defined area under a joint development agreement whereby parties are subject to mutual participatory rights and restrictions.

"***Basin***"—A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"***Bbl***"—One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"***Boe***"—Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"***Boe/d***"—Barrels of oil equivalent per day.

"***British thermal unit (BTU)***"—The heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"***Completion***"—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"***Condensate***"—Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

"***Developed acreage***"—The number of acres that are allocated or assignable to productive wells or wells capable of production.

"***Developed reserves***"—Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor when compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"***Development well***"—A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

"***Dry hole***"—A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

"***Economically producible***"—A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"***Exploratory well***"—A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"***Farm-in or farm-out***"—An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interests received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

“***Field***”—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition.

“***Formation***”—A layer of rock which has distinct characteristics that differ from nearby rock.

“***Fracture stimulation***”—A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

“***Gross acres or gross wells***”—The total acres or well, as the case may be, in which a working interest is owned.

“***Horizontal drilling***”—A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“***Joint development agreement***”—Includes joint venture agreements, farm-in and farm-out agreements, joint operating agreements and similar partnering arrangements.

“***MBbl***”—One thousand barrels of oil, condensate or NGLs.

“***MBoe***”—One thousand barrels of oil equivalent, determined using the equivalent of six Mcf of natural gas to one Bbl of crude oil.

“***Mcf***”—One thousand cubic feet of natural gas.

“***MMBoe***”—One million barrels of oil equivalent.

“***MMBtu***”—One million British thermal units.

“***MMcf***”—One million cubic feet of natural gas.

“***Net acres or net wells***”—The sum of the fractional working interest owned in gross acres or gross wells. An owner who has 50% interest in 100 acres owns 50 net acres.

“***Net revenue interest***”—An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

“***Possible reserves***”—Additional reserves that are less certain to be recognized than probable reserves.

“***Probable reserves***”—Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

“***Productive well***”—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“***Prospect***”—A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

“***Proved developed non-producing***”—Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved but non-producing reserves.

“***Proved developed reserves***”—Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

“***Proved reserves***”—Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

"***Proved undeveloped reserves (PUD)***"—Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"***Recompletion***"—The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"***Reserves***"—Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

"***Reservoir***"—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"***Royalty interest***"—An interest in an oil and natural gas property entitling the owner to a share of oil or gas production free of production costs.

"***Spacing***"—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"***Spud***"—The commencement of drilling operations of a new well.

"***Standardized measure of discounted future net cash flows***"—The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

"***Trend***"—A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

"***Unconventional formation***"—A term used in the oil and natural gas industry to refer to a formation in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) oil and gas shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates

"***Undeveloped acreage***"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

"***Wellbore***"—The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

"***Working interest***"—The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals and receive a share of the production. The working interest owners bear the exploration, development, and operating costs of the property.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Jones Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders' / members' equity, and cash flows present fairly, in all material respects, the financial position of Jones Energy, Inc. and its subsidiaries at December 31, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2015

Jones Energy, Inc.
Consolidated Balance Sheets
December 31, 2014 and 2013

(in thousands of dollars)	December 31, 2014	December 31, 2013
Assets		
Current assets		
Cash	$ 13,566	$ 23,820
Restricted cash	149	45
Accounts receivable, net		
Oil and gas sales	49,861	51,233
Joint interest owners	41,761	42,481
Other	12,512	16,782
Commodity derivative assets	121,519	8,837
Other current assets	3,374	2,392
Deferred tax assets	—	12
Total current assets	242,742	145,602
Oil and gas properties, net, at cost under the successful efforts method	1,638,860	1,297,228
Other property, plant and equipment, net	4,048	3,444
Commodity derivative assets	87,055	25,398
Other assets	20,352	15,006
Deferred tax assets	171	1,301
Total assets	$1,993,228	$1,487,979
Liabilities and Stockholders' Equity		
Current liabilities		
Trade accounts payable	$ 136,337	$ 89,430
Oil and gas sales payable	70,469	66,179
Accrued liabilities	19,401	10,805
Commodity derivative liabilities	—	10,664
Deferred tax liabilities	718	—
Asset retirement obligations	3,074	2,590
Total current liabilities	229,999	179,668
Long-term debt	360,000	658,000
Senior notes	500,000	—
Deferred revenue	13,377	14,531
Commodity derivative liabilities	28	190
Asset retirement obligations	10,536	8,373
Liability under tax receivable agreement	803	—
Deferred tax liabilities	26,612	3,093
Total liabilities	1,141,355	863,855
Commitments and contingencies (Note 10)		
Stockholders' equity		
Class A common stock, $0.001 par value; 12,672,260 shares issued and 12,649,658 shares outstanding at December 31, 2014 and 12,526,580 shares issued and outstanding at December 31, 2013	13	13
Class B common stock, $0.001 par value; 36,719,499 shares issued and outstanding at December 31, 2014 and 36,836,333 shares issued and outstanding at December 31, 2013	37	37
Treasury stock, at cost; 22,602 shares at December 31, 2014 and 0 shares at December 31, 2013	(358)	—
Additional paid-in-capital	177,133	173,169
Retained earnings (deficit)	38,682	(2,186)
Stockholders' equity	215,507	171,033
Non-controlling interest	636,366	453,091
Total stockholders' equity	851,873	624,124
Total liabilities and stockholders' equity	$1,993,228	$1,487,979

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

Jones Energy, Inc.

Consolidated Statements of Operations

Years Ended December 31, 2014, 2013 and 2012

(in thousands except per share data)	Year Ended December 31, 2014	2013	2012
Operating revenues			
Oil and gas sales	$378,401	$258,063	$148,967
Other revenues	2,196	1,106	847
Total operating revenues	380,597	259,169	149,814
Operating costs and expenses			
Lease operating	43,843	27,781	23,097
Production taxes	18,094	12,865	5,583
Exploration	3,453	1,710	356
Depletion, depreciation and amortization	181,669	114,136	80,709
Impairment of oil and gas properties	—	14,415	18,821
Accretion of discount	770	608	533
General and administrative (including non-cash compensation expense)	25,763	31,902	15,875
Total operating expenses	273,592	203,417	144,974
Operating income	107,005	55,752	4,840
Other income (expense)			
Interest expense	(46,726)	(30,774)	(25,292)
Net gain (loss) on commodity derivatives	189,641	(2,566)	16,684
Gain (loss) on sales of assets	297	(78)	1,162
Other income (expense), net	143,212	(33,418)	(7,446)
Income (loss) before income tax	250,217	22,334	(2,606)
Income tax provision (benefit)			
Current	53	85	—
Deferred	26,021	(156)	473
Total income tax provision (benefit)	26,074	(71)	473
Net income (loss)	224,143	22,405	(3,079)
Net income attributable to non-controlling interests	183,275	24,591	—
Net income (loss) attributable to controlling interests	$ 40,868	$ (2,186)	$ (3,079)
Earnings (Loss) per share:			
Basic	$ 3.26	$ (0.17)	—
Diluted	$ 3.26	$ (0.17)	—
Weighted average shares outstanding:			
Basic	12,526	12,500	—
Diluted	12,535	12,500	—

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

Jones Energy, Inc.

Statement of Changes in Stockholders' / Members' Equity

Years Ended December 31, 2014, 2013 and 2012

	Common Stock				Treasury Stock						
	Class A		Class B		Class A						
(amounts in thousands)	Shares	Value	Shares	Value	Shares	Value	Members' Equity	Additional Paid-in Capital	Retained (Deficit)/ Earnings	Non-controlling Interest	Total Stockholders' / Members' Equity
Balance at December 31, 2011	—	$—	—	$—	—	$ —	$ 345,909	$ —	$ —	$ —	$345,909
Issuance of Class C preferred units	—	—	—	—	—	—	85,000	—	—	—	85,000
Stock-compensation expense	—	—	—	—	—	—	570	—	—	—	570
Net income (loss)	—	—	—	—	—	—	(3,079)				(3,079)
Balance at December 31, 2012	—	—	—	—	—	—	428,400	—	—	—	428,400
Issuance of common stock	12,500	13	36,836	37	—	—	—	—	—	—	50
Proceeds from the sale of common stock	—	—	—	—	—	—	—	172,431	—	—	172,431
Reclassification of members' contributions	—	—	—	—	—	—	(464,037)	—	—	464,037	—
Stock-compensation expense	—	—	—	—	—	—	10,100	738	—	—	10,838
Distribution to members	—	—	—	—	—	—	(10,000)	—	—	—	(10,000)
Net income (loss)	—	—	—	—	—	—	35,537	—	(2,186)	(10,946)	22,405
Balance at December 31, 2013	12,500	13	36,836	37	—	—	—	173,169	(2,186)	453,091	624,124
Vested restricted shares	28	—	—	—	—	—	—	—	—	—	—
Stock-compensation expense	—	—	—	—	—	—	—	4,040	—	—	4,040
Exchange of Class B shares for Class A shares	117	—	(117)	—	—	—	—	(76)	—	—	(76)
Treasury stock	(23)	—	—	—	23	(358)	—	—	—	—	(358)
Net income	—	—	—	—	—	—	—	—	40,868	183,275	224,143
Balance at December 31, 2014	12,622	$13	36,719	$37	23	$(358)	$ —	$177,133	$38,682	$636,366	$851,873

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

Jones Energy, Inc.

Consolidated Statements of Cash Flows

Years Ended December 31, 2014, 2013 and 2012

(in thousands of dollars)	Year Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income (loss)	$ 224,143	$ 22,405	$ (3,079)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	181,669	114,136	80,709
Exploration expense	2,952	—	—
Impairment of oil and gas properties	—	14,415	18,821
Accretion of discount	770	608	533
Amortization of debt issuance costs	6,878	2,677	3,544
Accrued interest expense	7,823	1,891	456
Stock compensation expense	4,040	10,838	570
Other non-cash compensation expense (Note 9)	758	2,719	—
Amortization of deferred revenue	(1,154)	(469)	—
(Gain) loss on commodity derivatives	(189,641)	2,566	(16,684)
(Gain) loss on sales of assets	(297)	78	(1,162)
Deferred income tax provision	26,021	(156)	473
Other—net	376	79	129
Changes in assets and liabilities			
Accounts receivable	(832)	(56,804)	11,568
Other assets	(565)	163	1,873
Accounts payable and accrued liabilities	2,482	33,427	(13,201)
Net cash provided by operations	265,423	148,573	84,550
Cash flows from investing activities			
Additions to oil and gas properties	(474,619)	(197,618)	(125,493)
Acquisition of properties	—	(178,173)	(249,007)
Net adjustments to purchase price of properties acquired	15,709	—	—
Proceeds from sales of assets	448	1,607	9,158
Acquisition of other property, plant and equipment	(1,683)	(1,634)	(969)
Current period settlements of matured derivative contracts	(3,654)	7,586	28,675
Change in restricted cash	(104)	(45)	—
Net cash used in investing	(463,903)	(368,277)	(337,636)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	170,000	220,000	233,243
Repayment under long-term debt	(468,000)	(172,000)	(38,243)
Proceeds from senior notes	500,000	—	—
Payment of debt issuance costs	(13,416)	(683)	(9,324)
Issuance of preferred units	—	—	85,000
Proceeds from sale of common stock, net of expenses of $15.1 million	—	172,481	—
Purchase of treasury stock	(358)	—	—
Net cash provided by financing	188,226	219,798	270,676
Net increase (decrease) in cash	(10,254)	94	17,590
Cash			
Beginning of period	23,820	23,726	6,136
End of period	$ 13,566	$ 23,820	$ 23,726
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 29,560	$ 25,414	$ 20,759
Cash paid for income taxes	155	—	—
Change in accrued additions to oil and gas properties	49,025	41,945	3,355
Noncash acquisition of oil and gas properties	—	—	2,918
Current additions to ARO	1,995	1,516	662
Noncash distributions to members (Note 9)	—	10,000	—

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

Jones Energy, Inc.
Notes to the Consolidated Financial Statements

1. Organization and Description of Business

Organization

Jones Energy, Inc. (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"). As the sole managing member of JEH, the Company is responsible for all operational, management and administrative decisions relating to JEH's business and consolidates the financial results of JEH and its subsidiaries.

JEH 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 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.

The Company's certificate of incorporation authorizes two classes of common stock, Class A common stock and Class B common stock. The Class B common stock is held by the owners of JEH prior to the Company's initial public offering ("IPO") and can be exchanged (together with a corresponding number of units representing membership interests in JEH ("JEH 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. The Class B common stock has no economic rights but entitles its holder to one vote on all matters to be voted on by the Company's stockholders generally. As a result of the IPO, the pre-IPO owners retained 74.7% of the total economic interest in JEH, but with no voting rights or management power over JEH, resulting in the Company reporting this ownership interest as a non-controlling interest. Prior to the IPO, JEH owned the controlling interest in the Company; hence all of the net income earned prior to the IPO date is reflected in the net income attributable to non-controlling interests on the Consolidated Statement of Operations for the year ended December 31, 2013.

Description of Business

The Company is engaged in the acquisition, exploration, and production of oil and natural gas properties in the mid-continent United States. The Company's assets are located within two distinct basins in the Texas Panhandle and Oklahoma, the Anadarko Basin and the Arkoma Basin, and are owned by JEH and its operating subsidiaries. The Company is headquartered in Austin, Texas.

2. Significant Accounting Policies

Basis of Presentation

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All significant intercompany transactions and balances have been eliminated in consolidation. The financial statements reported for December 31, 2014 and 2013 and the results of the operations and the cash flows for each of the three years in the period ended December 31, 2014 include the Company and all of its subsidiaries.

2. Significant Accounting Policies (Continued)

Segment Information

The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas, and all of its operations are conducted in one geographic area of the United States.

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, fair value associated with business combinations, and asset retirement obligations ("ARO").

Financial Instruments

Cash, accounts receivable and accounts payable are recorded at cost. The fair value of accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments. The carrying value of the outstanding balance under the Company's Revolver (as defined in Note 6) represents fair value because the Revolver has variable interest rates, which are reflective of the Company's credit risk. The Company's senior notes have a fixed interest rate and are reported at historical value as of the initial measurement date when issued and their fair value is discussed in Note 4. Derivative instruments are recorded at fair value, as discussed below.

Cash

Cash and cash equivalents include highly liquid investments with a maturity of three months or less. At times, the amount of cash on deposit in financial institutions exceeds federally insured limits. Management monitors the soundness of the financial institutions and believes the Company's risk is not significant.

Accounts Receivable

Accounts receivable—Oil and gas sales consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. Accounts receivable—Joint interest owners consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable—Other consists at December 31, 2014 of derivative positions not settled as of the balance sheet date and severance tax refunds due from state agencies and at December 31, 2013 of the adjustments to the purchase price of the Sabine properties purchased in December 2013 and severance tax refunds due from state agencies. No interest is charged on past-due balances. The Company routinely assesses the recoverability of all material trade, joint interest and other receivables to determine their collectability, and reduces the carrying amounts by a valuation

2. Significant Accounting Policies (Continued)

allowance that reflects management's best estimate of the amounts that may not be collected. As of December 31, 2014 and 2013, the Company did not have significant allowances for doubtful accounts.

Concentration of Risk

Substantially all of the Company's accounts receivable are related to the oil and gas industry. This concentration of entities may affect the Company's overall credit risk in that these entities may be affected similarly by changes in economic and other conditions, including declines in commodity prices. As of December 31, 2014, 70% of Accounts receivable—Oil and gas sales are due from 5 purchasers and 67% of Accounts receivable—Joint interest owners are due from 5 working interest owners. As of December 31, 2013, 79% of Accounts receivable—Oil and gas sales were due from 8 purchasers, and 77% of 2013 Accounts receivable—Joint interest owners were due from 5 working interest owners. If any or all of these significant counterparties were to fail to pay amounts due to the Company, the Company's financial position and results of operations could be materially and adversely affected.

Dependence on Major Customers

The Company maintains a portfolio of crude oil and natural gas marketing contracts with large, established refiners and oil and gas purchasers. During the year ended December 31, 2014, the largest purchasers were Valero Energy Corp. ("Valero"), NGL Energy Partners LP, PVR Midstream LLC ("PVR Midstream"), Plains Marketing LP ("Plains Marketing"), and Monarch Natural Gas LLC which accounted for approximately 22%, 12%, 12%, 10% and 10% of consolidated oil and gas sales, respectively. During the year ended December 31, 2013, the largest purchasers were PVR Midstream, Unimark LLC, Mercuria Energy Group Ltd. ("Mercuria"), Valero, and Plains Marketing, which accounted for approximately 15%, 13%, 13%, 13% and 6% of consolidated oil and gas sales, respectively. During the year ended December 31, 2012, the largest purchasers were Unimark LLC, Mercuria, PVR Midstream, and Plains Marketing, which accounted for approximately 24%, 18%, 18% and 15% of consolidated oil and gas sales, respectively.

Management believes that there are alternative purchasers and that it may be necessary to establish relationships with such new purchasers. However, there can be no assurance that the Company can establish such relationships and that those relationships will result in an increased number of purchasers. Although the Company is exposed to a concentration of credit risk, management believes that all of the Company's purchasers are credit worthy.

Dependence on Suppliers

The Company's industry is cyclical, and from time to time, there can be an imbalance between the supply of and demand for drilling rigs, equipment, services, supplies and qualified personnel. During periods of oversupply, there can be financial pressure on suppliers. If the financial pressure leads to work interruptions or stoppages, the Company could be materially and adversely affected. Management believes that there are adequate alternative providers of drilling and completion services although it may become necessary to establish relationships with new contractors. However, there can be no assurance that the Company can establish such relationships and that those relationships will result in increased availability of drilling rigs or other services, or that they could be obtained on the same terms.

2. Significant Accounting Policies (Continued)

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 December 31, 2014 and 2013:

(in thousands of dollars)	2014	2013
Mineral interests in properties		
Unproved	$ 94,526	$ 99,134
Proved	1,001,194	958,816
Wells and equipment and related facilities	1,094,202	609,748
	2,189,922	1,667,698
Less: Accumulated depletion and impairment	(551,062)	(370,470)
Net oil and gas properties	$1,638,860	$1,297,228

Costs to acquire mineral interests in oil and natural gas properties are capitalized. Costs to drill and equip development wells and the related asset retirement costs are capitalized. The costs to drill and equip exploratory wells are capitalized pending determination of whether the Company has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are charged to expense. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the anticipated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of December 31, 2014 and 2013, we had no material capitalized costs associated with exploratory wells.

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 capitalized less than $0.1 million in interest costs during 2014 for one project. No interest costs were capitalized in 2013. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a proved field, the cost and related accumulated depletion, depreciation and amortization are eliminated from the field accounts, and the resultant gain or loss is recognized.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves, using the unit conversion ratio of six thousand cubic feet of gas to one barrel of oil equivalent. Depletion of the costs of wells and related equipment and facilities, including capitalized asset retirement costs, net of salvage values, is computed using proved developed reserves. The reserve base used to calculate depreciation, depletion, and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. Depletion of oil and gas properties amounted to $180.6 million, $113.3 million and $79.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

2. Significant Accounting Policies (Continued)

The Company reviews its proved oil and natural gas properties, including related wells and equipment, for impairment by comparing expected undiscounted future cash flows at a producing field level to the net capitalized cost of the asset. If the future undiscounted cash flows, based on the Company's estimate of future commodity prices, operating costs, and production, are lower than the net capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. Due to the significant assumptions associated with the inputs and calculations described, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. No impairments of proved properties were recorded in 2014 or 2013. The Company incurred impairment charges of $18.8 million related to its proved oil and natural gas properties and equipment in 2012.

The Company evaluates its unproved properties for impairment on a property-by-property basis. The Company's unproved property consists of acquisition costs related to its undeveloped acreage. The Company reviews the unproved property for indicators of impairment based on the Company's current exploration plans with consideration given to results of any drilling and seismic activity during the period and known information regarding exploration and development activity by other companies on adjacent blocks. The Company incurred no impairment charges related to its unproved properties in 2014 or 2012. In the fourth quarter of 2013, the Company recorded an impairment charge of $14.4 million related to its unproved Southridge properties in the Arkoma basin. As the Company did not drill the required number of wells by October 31, 2013 necessary to keep its joint development agreement with Southridge in effect, the Company lost its right to the undeveloped acreage. Impairment of oil and gas properties charges are recorded on the Consolidated Statement of Operations.

On the sale of an entire interest in an unproved property, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at December 31, 2014 and 2013:

(in thousands of dollars)	2014	2013
Leasehold improvements	$ 1,218	$ 1,060
Furniture, fixtures, computers and software	3,727	2,491
Vehicles	988	835
Aircraft	910	910
Other	219	134
	7,062	5,430
Less: Accumulated depreciation and amortization	(3,014)	(1,986)
Net other property, plant and equipment	$ 4,048	$ 3,444

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.

2. Significant Accounting Policies (Continued)

Depreciation and amortization of other property, plant and equipment amounted to $1.1 million, $0.8 million and $0.8 million during the years ended December 31, 2014, 2013 and 2012, respectively.

Oil and Gas Sales Payable

Oil and gas sales payable represents amounts collected from purchasers for oil and gas sales, which are due to other revenue interest owners. Generally, the Company is required to remit amounts due under these liabilities within 60 days of receipt.

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 years ended December 31, 2014, 2013 and 2012, 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 the Company 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

The Company's asset retirement obligations ("ARO") consist of future plugging and abandonment expenses on oil and natural gas properties. The Company estimates an ARO for each well in the period in which it is incurred based on estimated present value of plugging and abandonment costs, increased by an inflation factor to the estimated date that the well would be plugged. The resulting liability is recorded by increasing the carrying amount of the related long- lived asset. The liability is then accreted to its then-present value each period and the capitalized cost is depleted over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The ARO is classified as current or noncurrent based on the expect timing of

2. Significant Accounting Policies (Continued)

payments. A summary of the Company's ARO for the years ended December 31, 2014 and 2013 is as follows:

(in thousands of dollars)	2014	2013
ARO liability at beginning of year	$10,963	$ 9,506
Liabilities incurred(1)	1,995	1,515
Accretion of discount	770	608
Liabilities settled due to sale of related properties	(109)	(271)
Liabilities settled due to plugging and abandonment	(55)	(702)
Change in estimate	46	307
ARO liability at end of year	13,610	10,963
Less: Current portion of ARO at end of year	(3,074)	(2,590)
Total long-term ARO at end of year	$10,536	$ 8,373

(1) Includes $824 related to wells acquired in 2013 (see Note 3, "Acquisition of Properties").

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. The Company follows the "sales method" of accounting for its oil and natural gas revenue, so it recognizes revenue on all crude oil, natural gas, and natural gas liquids sold to purchasers. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves.

Production Costs

Production costs, including compressor rental, pumpers' salaries, saltwater disposal, ad valorem taxes, insurance, repairs and maintenance, expensed workovers and other operating expenses are expensed as incurred and included in lease operating expense on the Consolidated Statement of Operations.

Exploration Expenses

Exploration expenses include dry hole costs, lease extensions, delay rentals and geological and geophysical costs.

Income Taxes

Following its IPO on July 29, 2013, the Company began recording a federal and state income tax liability associated with its status as a corporation. No provision for federal income taxes was recorded prior to the IPO because the taxable income or loss was includable in the income tax returns of the individual partners and members. The Company is also subject to state income taxes. The State of Texas includes in its tax system a franchise tax applicable to the Company and an accrual for franchise taxes is included in the financial statements when appropriate.

2. Significant Accounting Policies (Continued)

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740—Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company records a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations require judgment by the Company and may be challenged by the taxation authorities. The Company follows ASC 740-10-25, which requires the use of a two-step approach for recognizing and measuring tax benefits taken or expected to be taken in a tax return and disclosures regarding uncertainties in income tax positions. Only tax positions that meet the more likely than not recognition threshold are recognized. The Company's policy is to include any interest and penalties recorded on uncertain tax positions as a component of income tax expense. The Company's unrecognized tax benefits or related interest and penalties are immaterial.

Liability under Tax Receivable Agreement

In connection with the IPO, the Company entered into a Tax Receivable Agreement (the "TRA") which obligated the Company to make payments to certain current and former owners equal to 85% of the applicable cash savings that the Company realizes as a result of tax attributes arising from exchanges of JEH Units and JEI Class B shares held by those owners for Class A shares of JEI common stock. The Company will retain the benefit of the remaining 15% of these tax savings.

As a result of exchanges made through December 31, 2014, the Company has accrued future tax benefits of $0.9 million and has recorded this amount as a deferred tax asset on its consolidated balance sheet. As of December 31, 2014, the Company has recorded a liability of $0.8 million associated with its future TRA obligation. The actual amount and timing of payments made under the TRA will depend upon a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers, and the portion of the Company's payments under the TRA constituting imputed interest. To the extent the Company does not realize all of the tax benefits in future years or in the event of a change in future tax rates, this liability may change.

As of December 31, 2014, the Company has made no payments under the TRA and does not anticipate making a material payment under the TRA in 2015.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Statement of Cash Flows

The Company presents its cash flows using the indirect method.

2. Significant Accounting Policies (Continued)

Related Party Transactions

In the years ended December 31, 2013 and 2012, the Company paid an annual administration fee to Metalmark of $0.7 million. This amount was charged to expense. As a result of the IPO, this fee is no longer payable to Metalmark.

On May 7, 2013, the Company entered into a natural gas sale and purchase agreement with Monarch Natural Gas, LLC, ("Monarch"), under which Monarch has the first right to gather the natural gas the Company produces from dedicated properties, process the NGLs from this natural gas production and market the processed natural gas and extracted NGLs. Under the Monarch agreement, the Company is paid a specified percentage of the value of the NGLs extracted and sold by Monarch, based on a set liquids recovery percentage, and the amount received from the sale of the residue gas, after deducting a fixed volume for fuel, lost and unaccounted for gas. The Company produced approximately 1.4 MMBoe of natural gas and NGLs for the year ended December 31, 2014 and 0.8 MMBoe of natural gas and NGLs for the year ended December 31, 2013, from the properties that became subject to the Monarch agreement. The initial term of the agreement runs for 10 years from the effective date of September 1, 2013.

At the time the Company entered into the agreement, Metalmark Capital owned approximately 81% of the outstanding equity interests of Monarch. In addition, Metalmark Capital beneficially owns in excess of five percent of the Company's outstanding equity interests and two of our directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital. In connection with the Company's entering into the Monarch agreement, Monarch issued to JEH equity interests in Monarch having a deemed value of $15 million. JEH assigned $2.4 million of the Monarch equity interests to Jonny Jones, the Company's chief executive officer and chairman of the board, and reserved $2.6 million of the Monarch equity interests to a benefit plan established for certain of the Company's officers, including Mike McConnell, Robert Brooks and Eric Niccum. The remaining $10 million of Monarch equity was distributed to certain of the pre-IPO owners, which include Metalmark Capital, Wells Fargo, the Jones family entities, and certain of the Company's officers and directors, including Jonny Jones, Mike McConnell and Eric Niccum.

In September 2014, the Company signed a 10-year oil gathering and transportation agreement with Monarch Oil Pipeline LLC, pursuant to which Monarch Oil Pipeline, LLC will build, at its expense, a new oil gathering system and connect to dedicated Company leases in Texas. At the time the Company entered into the agreement, Metalmark Capital owned the majority of the outstanding equity interests of Monarch Oil Pipeline, LLC and/or its parent. The system is expected to begin service during the second quarter of 2015 and provide connectivity to both a regional refinery market as well as the Cushing market hub. The Company has reserved capacity of up to 12,000 barrels per day on the system with the potential to increase throughput at a future date.

Stock Compensation

JEH implemented a management incentive plan effective January 1, 2010, that provided awards of membership interests in JEH to members of senior management ("management units"). The management unit grants awarded prior to the initial filing of the IPO registration statement in March 2013 had a dual vesting schedule and were fully vested as of December 31, 2014. Grants awarded after the initial IPO registration statement generally have a single vesting structure of five equal annual installments and were valued at the IPO price, adjusted for equivalent shares. Both the vested and

2. Significant Accounting Policies (Continued)

unvested management units were converted into JEH Units and shares of Class B common stock at the IPO date. At December 31, 2014, there were 274,385 unvested JEH Units and shares of Class B common stock that will become convertible into a like number of shares of Class A common stock upon vesting.

Under the Jones Energy, Inc. 2013 Omnibus Incentive Plan, established in conjunction with the Company's IPO, the Company reserved 3,850,000 shares of Class A common stock for director and employee stock-based compensation awards.

During 2014, the Company granted performance unit and restricted stock unit awards to certain officers and employees under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The fair value of the performance units was based on the grant date fair value (using a Monte Carlo simulation model) and is expensed on a straight-line basis over the applicable three-year performance period. The number of shares of Class A common stock issuable upon vesting of the performance unit awards ranges from zero to 200% based on the Company's total shareholder return relative to an industry peer group over the applicable three-year performance period. The fair value of the restricted stock unit awards was based on the value of the Company's Class A common stock on the date of grant and is expensed on a straight-line basis over the applicable three-year vesting period.

In September 2014 and 2013, the Company granted each of the outside members of the Board of Directors 5,486 and 6,645 shares, respectively, of restricted Class A common stock under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The fair value of the restricted stock grants was based on the value of the Company's Class A common stock on the date of grant and is expensed on a straight-line basis over the one-year vesting period.

Refer to Note 7, "Stock-based Compensation," for additional information regarding director and employee stock-based compensation awards

Business Combinations

For acquisitions of working interests that are accounted for as business combinations, the results of operations are included in the Consolidated Statement of Operations from the date of acquisition. Purchase prices are allocated to assets acquired based on their estimated fair values at the time of acquisition. 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. The fair value measurement is based on the assumptions of market participants and not those of the reporting entity. Therefore, entity-specific intentions do not impact the measurement of fair value. The fair value of oil and natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant inputs including: 1) oil and gas prices, 2) projections of estimated quantities of oil and natural gas reserves, including those classified as proved, probable and possible, 3) projections of future rates of production, 4) timing and amount of future development and operating costs, 5) projected reserve recovery factors, and 6) weighted average cost of capital.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued *Accounting Standards Update* ("ASU") No. 2014-09, "*Revenue from Contracts with Customers*," which creates a new topic in the Accounting Standards Codification ("ASC"), topic 606, "*Revenue from Contracts with Customers*."

2. Significant Accounting Policies (Continued)

This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2016 and may be applied on either a full or modified retrospective basis. Early adoption is not permitted. We do not expect the adoption of these provisions to have a significant impact on the Company's consolidated financial statements. However, we will continue to assess the anticipated impact as further implementation guidance is released from the FASB.

In August 2014, the FASB issued ASU No. 2014-15, "*Presentation of Financial Statements—Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*." This ASU requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a "going concern" and to provide disclosures when certain criteria are met. Substantial doubt exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued (or available to be issued). The amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early adoption is permitted. We do not expect the adoption of these disclosures to have a significant impact on the Company's consolidated financial statements.

In January 2015, the FASB issued Accounting Standards Update No. 2015-01, *Income Statement—Extraordinary and Unusual Items* ("ASU 2015-01"). ASU 2015-01 removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed. ASU 2015-01 is effective for interim and annual reporting periods beginning after December 15, 2015. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

3. Acquisition of Properties

No property acquisitions that would qualify as a business combination occurred during the twelve months ended December 31, 2014.

On December 18, 2013, JEH closed on the purchase of certain oil and natural gas properties located in Texas and western Oklahoma from Sabine Mid-Continent, LLC, for a purchase price of $193.5 million (referred to herein as the "Sabine acquisition" or "Sabine"), subject to customary closing adjustments. The acquired assets included both producing properties and undeveloped acreage. The purchase was financed with borrowings under the Revolver. In the second quarter of 2014, the Company made a final determination with the sellers as to the purchase price resulting in a final purchase price of $179.2 million. The amount of the total purchase price allocated to undeveloped oil and gas properties was reduced by these adjustments. The adjustments were retroactively applied to our

3. Acquisition of Properties (Continued)

December 31, 2013 Consolidated Balance Sheet as a reduction to oil and gas properties and an increase in receivables. The adjusted purchase price was allocated as follows:

(in thousands of dollars)	
Oil and gas properties	
Unproved	$ 32,964
Proved	147,024
Asset retirement obligations	(824)
Total purchase price	$179,164

The unaudited pro forma results presented below have been prepared to include the effect of the Sabine acquisition on our results of operations for the year ended December 31, 2013. 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, 2013 or to project our results of operations for any future date or period.

(in thousands of dollars)	Post Acquisition(1)	Year Ended December 31, 2013 Pro Forma
	(unaudited)	(unaudited)
Total operating revenue	$1,365	$308,773
Total operating expenses	291	229,648
Operating income	1,074	79,125
Net income	1,074	45,778

(1) Represents revenues and expenses for the post acquisition period of December 18, 2013 to December 31, 2013 included in the Consolidated Statement of Operations.

On December 20, 2012, JEH 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 included both producing properties and undeveloped acreage. The purchase was financed with additional equity capital and borrowings under the Revolver. In the second quarter of 2013, the Company 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:

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

The unaudited pro forma results presented below have been prepared to include the effect of the Chalker acquisition on our results of operations for the year ended December 31, 2012. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if

3. Acquisition of Properties (Continued)

the acquisition had been completed on January 1, 2012 or to project our results of operations for any future date or period.

(in thousands of dollars)	Year Ended December 31, 2012 Pro Forma (unaudited)
Total operating revenue	$194,685
Total operating expenses	161,053
Operating income	33,632
Net income	25,713

Both acquisitions qualified as a business combination under ASC 805. The valuation to determine the fair values were principally based on the discounted cash flows of 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 market at the time of acquisition.

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 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.

4. Fair Value Measurement (Continued)

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 in 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 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 December 31, 2014 and 2013, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

	December 31, 2014			
	Fair Value Measurements Using			
(in thousands of dollars)	(Level 1)	(Level 2)	(Level 3)	Total
Commodity Price Hedges				
Current assets	$—	$120,604	$ 915	$121,519
Long-term assets	—	85,162	1,893	87,055
Current liabilities	—	—	—	—
Long-term liabilities	—	—	28	28

	December 31, 2013			
	Fair Value Measurements Using			
(in thousands of dollars)	(Level 1)	(Level 2)	(Level 3)	Total
Commodity Price Hedges				
Current assets	$—	$ 8,837	$ —	$ 8,837
Long-term assets	—	25,967	(569)	25,398
Current liabilities	—	10,188	476	10,664
Long-term liabilities	—	—	190	190

4. Fair Value Measurement (Continued)

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 December 31, 2014.

	Quantitative Information About Level 3 Fair Value Measurements			
Commodity Price Hedges	**Fair Value (000's)**	**Valuation Technique**	**Unobservable Input**	**Range**
Natural gas liquid swaps	$3,045	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures	$8.09 - $75.52 per barrel
Natural gas basis swaps	$ (265)	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas basis swaps	$(0.11) - $(0.17) per barrel

Significant increases/decreases in natural gas liquid 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 years ended December 31, 2014 and 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.

(in thousands of dollars)	
Balance at December 31, 2012, net	$(1,519)
Purchases	(1,095)
Settlements	(210)
Transfers to Level 2	(753)
Changes in fair value	2,342
Balance at December 31, 2013, net	(1,235)
Purchases	668
Settlements	476
Transfers into Level 3	(265)
Transfers to Level 2	332
Changes in fair value	2,804
Balance at December 31, 2014, net	$ 2,780

Transfers from Level 3 to Level 2 represent the Company's natural gas basis swaps for which observable forward curve pricing information has become readily available. Purchases represent natural gas liquid swaps that the Company entered into that do not have observable forward curve pricing information. There were no transfers into Level 3 for the years ended December 31, 2014 and 2013.

4. Fair Value Measurement (Continued)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements:

	December 31, 2014		December 31, 2013	
(in thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Revolver	$360,000	$360,000	$498,000	$498,000
Term loan	—	—	160,000	160,000
2022 Notes	500,000	384,375	—	—

The Revolver is 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 approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

The fair value of the 2022 Notes (as defined in Note 6) is based on pricing that is readily available in the public market. Accordingly, the 2022 Notes are classified as Level 2 in the valuation hierarchy as the pricing is based on quoted market prices for the debt securities.

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 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. No impairment charges on the Company's proved properties were recorded during the years ended December 31, 2014 and 2013. During 2012, unamortized capitalized costs of certain properties were higher than their expected undiscounted future cash flows due primarily to downward reserve revisions, drilling of marginal or uneconomic wells, or development dry holes in certain producing fields. As a result, the Company recorded charges of $18.8 million during the year ended December 31, 2012.

Additionally, the Company reviews its unproved properties for indicators of impairment based on the Company's current exploration plans. In the fourth quarter of 2013, the Company recorded an impairment charge of $14.4 million related to the Southridge properties. As the Company did not drill the required number of wells by October 31, 2013 necessary to keep its joint development agreement with Southridge in effect, the Company lost its right to the undeveloped acreage and associated reserves. The Company incurred no impairment charges related to its unproved properties in 2014 or 2012.

4. Fair Value Measurement (Continued)

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.

5. Derivative Instruments and Hedging Activities

The Company had various commodity derivatives in place that could affect its future operations as of December 31, 2014 and 2013, as follows:

Hedging Positions

		December 31, 2014			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 75.05	$ 100.95	$ 84.20	
	Barrels per month	45,000	184,054	113,852	December 2018
Natural gas swaps	Exercise price	$ 3.37	$ 6.45	$ 4.40	
	mmbtu per month	710,000	1,772,584	1,175,275	December 2018
Basis swaps	Contract differential	$ (0.39)	$ (0.11)	$ (0.21)	
	mmbtu per month	320,000	980,000	716,667	March 2016
Natural gas liquids swaps	Exercise price	$ 8.09	$ 95.24	$ 42.46	
	Barrels per month	2,000	143,000	50,444	December 2017

		December 31, 2013			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 81.70	$ 102.84	$ 89.03	
	Barrels per month	29,000	161,613	96,149	December 2017
Natural gas swaps	Exercise price	$ 3.88	$ 6.90	$ 4.26	
	mmbtu per month	510,000	1,290,000	830,275	December 2017
Basis swaps	Contract differential	$ (0.43)	$ (0.11)	$ (0.34)	
	mmbtu per month	320,000	690,000	467,037	March 2016
Natural gas liquids swaps	Exercise price	$ 6.72	$ 95.24	$ 32.98	
	Barrels per month	2,000	118,000	46,646	December 2017

The Company recognized a net gain on derivative instruments of $189.6 million for the year ended December 31, 2014, a net loss of $2.6 million for the year ended December 31, 2013, and a net gain of $16.7 million for the year ended December 31, 2012.

Offsetting Assets and Liabilities

As of December 31, 2014, the counterparties to our commodity derivative contracts consisted of seven financial institutions. Substantially, all of our counterparties or their affiliates are also lenders under the Revolver. We are not generally required to post additional collateral under our derivative agreements.

5. Derivative Instruments and Hedging Activities (Continued)

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 that are netted on our Consolidated Balance Sheet as of December 31, 2014 and December 31, 2013:

(in thousands of dollars)	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
December 31, 2014					
Commodity derivative contracts					
Assets	$208,646	$ (72)	$208,574	$ —	$208,574
Liabilities	(100)	72	(28)	—	(28)
December 31, 2013					
Commodity derivative contracts					
Assets	$ 38,071	$(6,035)	$ 32,036	$ 2,199	$ 34,235
Liabilities	(14,347)	6,035	(8,312)	(2,542)	(10,854)

6. Long-Term Debt

Senior Notes

On April 1, 2014, JEH and its wholly-owned subsidiary, Jones Energy Finance Corp. (together the "Issuers"), sold $500.0 million in aggregate principal amount of the Issuers' 6.75% Senior Notes due 2022 (the "2022 Notes"). The Company used the net proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan ($160.0 million), a portion of the outstanding borrowings under the Revolver ($308.0 million) and for working capital and general corporate purposes. The Company subsequently terminated the Term Loan in accordance with its terms. The 2022 Notes bear interest at a rate of 6.75% per year, payable semi-annually on April 1 and October 1 of each year beginning October 1, 2014. As of December 31, 2014, the Company had $8.4 million in interest accrued related to the 2022 Notes. Total interest expense related to the 2022 Notes amounted to $25.3 million for the year ended December 31, 2014.

The 2022 Notes are guaranteed on a senior unsecured basis by the Company and by all of its significant subsidiaries. The 2022 Notes will be senior in right of payment to any future subordinated indebtedness of the Issuers.

The Company may redeem the 2022 Notes at any time on or after April 1, 2017 at a declining redemption price set forth in the indenture, plus accrued and unpaid interest.

The indenture governing the 2022 Notes contains covenants that, among other things, limit the ability of the Company to incur additional indebtedness or issue certain preferred stock, pay dividends on capital stock, transfer or sell assets, make investments, create certain liens, enter into agreements that restrict dividends or other payments from the Company's restricted subsidiaries to the Company,

6. Long-Term Debt (Continued)

consolidate, merge or transfer all of the Company's assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the Notes are rated investment grade by Standard & Poor's or Moody's.

Other 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"), each of which have been amended periodically. On April 1, 2014, the Term Loan was repaid in full and terminated in connection with the issuance of the 2022 Notes. On November 6, 2014, the Company amended the Revolver to, among other things, increase the borrowing base under the Revolver from $550.0 million to $625.0 million until the next redetermination thereof, and extend the maturity date of the Revolver to November 6, 2019. The Company's oil and gas properties are pledged as collateral to secure its obligations under the Revolver. The borrowing base on the Revolver was subsequently adjusted to $562.5 million in accordance with its terms as a result of the issuance of the 2023 Notes in February 2015.

The terms of the Revolver require the Company to make periodic payments of interest on the loans outstanding thereunder, with all outstanding principal and interest under the Revolver due on the maturity date thereof. The Revolver is subject to a borrowing base which limits the amount of borrowings which may be drawn thereunder. The borrowing base will be redetermined by the lenders at least semi-annually on or about April 1 and October 1 of each year. Interest on the Revolver is calculated, at the Company's option, at either (a) the LIBO rate for the applicable interest period plus a margin of 1.50% to 2.50% based on the level of borrowing base utilization at such time or (b) the greatest of the federal funds rate plus 0.50%, the one-month adjusted LIBO rate plus 1.00%, or the prime rate announced by Wells Fargo Bank, N.A. in effect on such day, in each case plus a margin of 0.50% to 1.50% based on the level of borrowing base utilization at such time. For the year ended December 31, 2014, the average interest rate under the Revolver was 2.51% on an average outstanding balance of $333.8 million. For the year ended December 31, 2013, the average interest rate under the Revolver was 3.01% on an average outstanding balance of $384.9 million.

Total interest and commitment fees under the Revolver and Term Loan were $13.0 million, $27.0 million, and $21.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. $3.8 million in unamortized deferred financing costs were charged to interest expense during 2014 in connection with repayment of the Term Loan.

The Revolver is 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 approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

We are subject to certain covenants under the Revolver which include, but are not limited to, restrictions on asset sales, distributions to members, and incurrence of additional indebtedness, and financial covenants which require the maintenance of certain financial ratios, including a maximum leverage ratio, and a minimum current ratio. The Company was in compliance with these covenants at December 31, 2014.

7. Stock-based Compensation

Management Units

Prior to the IPO, JEH granted management units under a previously existing management incentive plan. These awards had various vesting schedules, and a portion of the management units vested in a lump sum at the IPO date. Both the vested and unvested management units were converted into JEH Units and shares of Class B common stock at the IPO date. As of December 31, 2014, there were 274,385 unvested JEH Units and shares of Class B common stock under this plan. No new JEH Units and Class B shares are created upon a vesting event. The JEH Units (together with a corresponding number of shares of Class B common stock) will become exchangeable into a like number of shares of Class A common stock upon vesting or forfeiture. The following table summarizes information related to the vesting of JEH Units:

	JEH 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	(998,032)	$ 9.96
Unvested at December 31, 2013	457,150	$12.46
Granted	21,405	$ 6.66
Forfeited	(21,405)	$ 6.66
Vested	(182,765)	$ 8.65
Unvested at December 31, 2014	274,385	$15.00

Stock compensation expense associated with the management units and JEH Units for the years ended December 31, 2014, 2013 and 2012 was $1.6 million, $10.7 million, and $0.6 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations.

Restricted Stock Awards

On September 23, 2014, the Company granted restricted stock awards to non-employee members of the Board of Directors. Each of the five directors was awarded 5,486 restricted shares of Class A common stock, contingent on the director serving as a director of the Company for a one-year service period in accordance with the terms of the award. The fair value of the awards was based on the value of the Company's Class A common stock on the date of grant.

On September 4, 2013, the Company granted restricted stock awards to non-employee members of the Board of Directors. Each of the four directors was awarded 6,645 restricted shares of Class A common stock, contingent on the director serving as a director of the Company for a one-year service period from the date of grant. The fair value of the awards was based on the value of the Company's

7. Stock-based Compensation (Continued)

Class A common stock on the date of grant. These awards are fully vested as of December 31, 2014. The total number of shares awarded to the directors is as follows:

Director Restricted Stock Awards

	Restricted Stock Awards	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2013	—	—
Granted	26,580	$15.05
Forfeited	—	—
Vested	—	—
Unvested at December 31, 2013	26,580	$15.05
Granted	27,430	$18.77
Forfeited	—	—
Vested	(26,580)	$15.05
Unvested at December 31, 2014	27,430	$18.77

Stock compensation expense associated with the Board of Directors awards for the year ended December 31, 2014 was $0.4 million and for the year ended December 31, 2013 was $0.1 million and is included in general and administrative expenses on the Company's Consolidated Statement of Operations.

Restricted Stock Unit Awards

During the year ended December 31, 2014, the Company granted 340,001 restricted stock unit awards to certain officers and employees of the Company. The fair value of the restricted stock unit awards was based on the value of the Company's Class A common stock on the date of grant and is expensed on a straight-line basis over the applicable three-year vesting period. The total number of units awarded to the officers and employees is as follows:

Employee Restricted Stock Unit Awards

	Restricted Stock Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014	—	—
Granted	340,001	$17.31
Forfeited	(13,688)	$17.07
Vested	(1,416)	$17.07
Unvested at December 31, 2014	324,897	$17.33

Stock compensation expense associated with the employee restricted stock unit awards for the twelve months ended December 31, 2014 was $1.1 million, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations.

7. Stock-based Compensation (Continued)

Performance Unit Awards

During the twelve months ended December 31, 2014, the Company granted 201,318 performance unit awards to certain officers of the Company. Upon the completion of the applicable three-year performance period, each officer will vest in a number of performance units. The number of performance units in which each officer vests at such time will range from 0% to 200% based on the Company's total shareholder return relative to an industry peer group over the applicable three-year performance period. Each vested performance unit is exchangeable for one share of the Company's Class A common stock. The grant date fair value of the performance units was determined using a Monte Carlo simulation model, which results in an expected percentage of performance units earned. The fair value of the performance units is expensed on a straight-line basis over the applicable three-year performance period.

The total number of units awarded to the officers is as follows:

Employee Performance Unit Awards

	Performance Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014	—	—
Granted	201,318	$21.65
Forfeited	(8,320)	$21.65
Vested	—	—
Unvested at December 31, 2014	192,998	$21.65

Stock compensation expense associated with the performance unit awards for the twelve months ended December 31, 2014 was $0.9 million, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations.

The Monte Carlo simulation process is a generally accepted statistical technique used, in this instance, to simulate future stock prices for the Company and the components of the peer group. The simulation uses a risk-neutral framework along with the risk-free rate of return, the volatility of each entity, and the correlations of each entity with the other entities in the peer group. A stock price path has been simulated for the Company and each peer company and is used to determine the payout percentages and the stock price of the Company's common stock as of the vesting date. The ending stock price is multiplied by the payout percentage to determine the projected payout, which is then discounted with the risk-free rate of return to the grant date to determine the grant date fair value for that simulation. When enough simulations are generated, the resulting distribution gives a reasonable estimate of the range of future expected stock prices.

7. Stock-based Compensation (Continued)

The following assumptions were used for the Monte Carlo simulation model to determine the grant date fair value and associated compensation expense during the twelve months ended December 31, 2014:

Stock Price(1)	$17.07
Beginning Average Stock Price(2)	$14.78
Expected Volatility(3)	46.95%
Risk-Free Rate of Return(4)	0.61%

(1) Based on the closing price of Jones Energy, Inc. Class A common stock on May 20, 2014.

(2) Based on the 10 trading days immediately prior to the beginning of the performance period.

(3) Based on the average historical volatilities over the most recent 2.62-year period for the Company and each peer company using daily stock prices through May 20, 2014. The measurement period reflects the 2.62 years remaining in the performance period as of the grant date.

(4) Based on the yield curve of U.S. Treasury rates as of May 20, 2014.

Based on these assumptions, the Monte Carlo simulation model resulted in a simulated fair value of $21.65 based on an expected percentage of performance units earned of 126.80%.

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. Shares of Class B common stock are not included in the calculation of earnings per share because they are not participating securities and have no economic interest in the Company. Diluted earnings per share takes into account the potential dilutive effect of shares that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees. In accordance with ASC 260, Earnings Per Share, awards of nonvested shares shall be considered outstanding as of the respective grant dates for purposes of computing diluted EPS even though the award is contingent upon vesting. For the twelve months ended December 31, 2014, 27,430 restricted stock shares, 54,656 restricted stock units and 192,998 performance units were excluded from the calculation as they would have had an anti-dilutive effect. The following is a calculation of the basic and diluted weighted-average number of shares of Class A common stock outstanding and EPS. 2014 is calculated using the twelve months ended December 31, 2014. 2013 is calculated for the period from July 29, 2013, the closing date of the IPO, to December 31, 2013.

8. Earnings per Share (Continued)

Basic Earnings per Share

(in thousands, except per share data)	2014	2013
Income (numerator):		
Net income (loss) attributable to controlling interests	$40,868	$(2,186)
Weighted-average shares (denominator):		
Weighted-average number of shares of Class A common stock	12,526	12,500
Earnings (loss) per share:		
Basic earnings per share	$ 3.26	$ (0.17)

Diluted Earnings per Share

(in thousands, except per share data)	2014	2013
Income (numerator):		
Net income (loss) attributable to controlling interests	$40,868	$(2,186)
Weighted-average shares (denominator):		
Weighted-average number of shares of Class A common stock	12,535	12,500
Earnings (loss) per share:		
Diluted earnings per share	$ 3.26	$ (0.17)
Anti-dilutive shares of Class A common stock	275	27

9. Monarch Investment

On May 7, 2013, the Company entered into a marketing agreement with 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%, or $10 million, of the Monarch equity interests to the Company's owners pro rata based on equity contributions and approximately 16% of the interests to a member of management. The remaining approximately 17% of the equity interests were reserved for distribution to management through an incentive plan. During the year ended December 31, 2014, $0.5 million of the equity interests were distributed to management under the incentive plan. The Company recognized expense of $0.8 million during the year ended December 31, 2014 and $0.3 million during the year ended December 31, 2013 in connection with the incentive plan. In addition, the Company recorded deferred revenue of $15.0 million related to the marketing agreement 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 $1.2 million of the deferred revenue balance during the year ended December 31, 2014, and $0.5 million of deferred revenue during the year ended December 31, 2013. This revenue is recorded in other revenues on the Company's Consolidated Statement of Operations.

10. Commitments and Contingencies

Lease obligations

The Company leases approximately 43,000 square feet of office space in Austin, TX under an operating lease arrangement. Future minimum payments for all noncancellable operating leases extending beyond one year at December 31, 2014 are as follows:

(in thousands of dollars)	
Years Ending December 31,	
2015	$ 944
2016	954
2017	1,038
2018	1,101
2019	1,122
Thereafter	377
	$5,536

Rent expense under operating leases was $0.9 million, $0.8 million and $0.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Litigation

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 current matters will not have a material adverse effect on its financial position, results of operations, or liquidity.

11. Benefit Plans

The Company established a 401(k) tax-deferred savings plan (the "Plan") for the benefit of employees. The Plan is a defined contribution plan and the Company may match a portion of employee contributions. For each of the years ended December 31, 2014 and 2013, $0.3 million was contributed to the Plan.

In 2013, the Company established a 409A tax-deferred savings plan for the benefit of key employees. This plan is a defined contribution plan, and the Company may match a portion of employee contributions. For each of the years ended December 31, 2014 and 2013, the Company made no contributions to this plan.

12. Income Taxes

Following its IPO, the Company began recording a federal and state income tax liability associated with its status as a corporation. Prior to the IPO, the Company only recorded a provision for Texas franchise tax as the Company's taxable income or loss was includable in the income tax returns of the individual partners and members.

The Company will recognize a tax liability on its share of pre-tax book income, exclusive of the non-controlling interest. JEH is not subject to income tax at the federal level and only recognizes Texas

12. Income Taxes (Continued)

franchise tax expense. The following table summarizes the tax provision for the years ended December 31, 2014, 2013 and 2012:

(in thousands of dollars)	Year Ended December 31, 2014	2013	2012
Current tax expense:			
Federal	$ 53	$ 85	$ —
State	—	—	—
Total current expense	53	85	—
Deferred tax expense (benefit):			
Federal	21,996	(1,260)	—
State	4,025	1,104	473
Total deferred expense (benefit)	26,021	(156)	473
Total tax expense (benefit)	$26,074	$ (71)	$473
Tax expense (benefit) attributable to controlling interests	$22,675	$(1,223)	$473
Tax expense attributable to non-controlling interests	3,399	1,152	—
Total income tax expense (benefit)	$26,074	$ (71)	$473

For the pre-IPO period of the year ended December 31, 2013 and for the entire year ended December 31, 2012, the reported taxes in the table above relate solely to the Texas franchise tax liability of JEH.

A reconciliation of the Company's provision for income taxes as reported and the amount computed by multiplying income before taxes, less non-controlling interest, by the U.S. federal statutory rate of 35%:

(in thousands of dollars)	2014	2013
Provision calculated at federal statutory income tax rate:		
Net income before taxes	$250,217	$22,334
Statutory rate	35%	35%
Income tax expense computed at statutory rate	$ 87,577	$ 7,817
Less: Non-controlling interests	(65,336)	(9,009)
Income tax expense (benefit) attributable to controlling interests	22,241	(1,192)
State and local income taxes, net of federal benefit	626	(49)
Other	(192)	18
Tax expense (benefit) attributable to controlling interests	22,675	(1,223)
Tax expense attributable to non-controlling interests	3,399	1,152
Total income tax expense (benefit)	$ 26,074	$ (71)

For the year ended December 31, 2012, the calculation is not applicable as the Company was not subject to federal income taxes prior to the IPO.

12. Income Taxes (Continued)

The Company is subject to federal, state, and local income and franchise taxes. As such, deferred income taxes result from temporary differences between the carrying amounts of assets and liabilities of the Company for financial reporting purposes and the amounts used for income tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates in effect in the years in which those temporary differences are expected to reverse.

Significant components of the Company's deferred tax assets and deferred tax liabilities consisted of the following:

(in thousands of dollars)	As of December 31, 2014	2013
Deferred tax assets		
Investment in consolidated subsidiary JEH	$ —	$ 526
Net operating loss	8,223	649
Section 754 election tax basis adjustment	945	—
Alternative minimum tax credits	53	86
Other deferred tax asset	232	52
Total deferred tax assets	9,453	1,313
Deferred tax liabilities		
Current state deferred tax liability	718	—
Investment in consolidated subsidiary JEH	29,163	—
Noncurrent state deferred tax liability	6,731	3,093
Total deferred tax liabilities	36,612	3,093
Net deferred tax assets (liabilities)	(27,159)	(1,780)
Valuation allowance	—	—
Net deferred tax assets (liabilities)	$(27,159)	$(1,780)

The Company has a federal net operating loss carry-forward totaling $22.4 million and state net operating loss carry-forward of $9.6 million, both of which expire between 2033 and 2034. No valuation allowance has been recorded as management believes that there is sufficient future taxable income to fully utilize its deferred tax assets. This future taxable income will arise from reversing temporary differences due to the excess of the book carrying value of oil and gas properties over their corresponding tax basis. In addition, the Company may elect to capitalize intangible drilling costs, rather than expensing these costs, in order to prevent an operating loss carryforward from expiring unused.

Separate federal and state income tax returns are filed for Jones Energy, Inc. and Jones Energy Holdings, LLC. JEH's Texas franchise tax returns are subject to audit for 2010 through 2014. The tax years 2011 through 2014 remain open to examination by the major taxing jurisdictions to which the Company is subject. The Company is not currently under audit by the IRS or any state jurisdiction.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2014 and December 31, 2013 there was no material liability or expense for the periods then ended recorded for payments of interest and penalties

12. Income Taxes (Continued)

associated with uncertain tax positions or material unrecognized tax positions and the Company's unrecognized tax benefits were not material.

Tax Receivable Agreement

JEH intends to make an election under Section 754 of the Internal Revenue Code (the "Code") effective for 2014 and future tax years. As a result, JEH will be required to adjust the tax basis of the assets of JEH at the time of an exchange of JEH units and Class B common stock held by the non-controlling interest members of the Company for Class A common stock. The tax basis adjustments are expected to result in increases in the tax basis of the assets of JEH that would otherwise have not been available. This increase in tax basis allows the Company to reduce the amount of future tax payments to the extent that the Company has future taxable income.

As a result of the increase in tax basis generated in exchanges made as of December 31, 2014, the Company is entitled to future tax benefits of $0.9 million and has recorded this amount as a deferred tax asset on its consolidated balance sheet. Under the terms of the TRA entered into prior to the IPO, JEI will pay 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax that the Company actually realizes as a result of these increases in tax basis to the exchanging member who generated the increased tax basis. For purposes of making payments under the TRA, actual cash savings in income tax in a given year will be computed by comparing the Company's actual income tax liability to the amount of such taxes the Company would have been required to pay had there been no increase to the tax basis of the assets of JEH as a result of the exchanges.

While the actual amount and timing of payments under the TRA will depend upon a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the value of individual assets, and the portion of the Company's payments under the TRA constituting imputed interest, the Company has estimated that the payments that will be made to the pre-IPO members who have exchanged shares as of December 31, 2014 will be $0.8 million and has recorded this obligation as a liability on the consolidated balance sheet. To the extent the Company does not realize all of the tax benefits in future years or in the event of a change in future tax rates, this liability may change.

As of December 31, 2014, the Company has not made any payments under the TRA to pre-IPO members who have exchanged JEH units and Class B common stock for Class A common stock. The Company does not anticipate making a material payment under the TRA in 2015.

13. Subsequent Events

Public Offering of Class A Common Stock

On February 17, 2015, the Company completed the issuance and sale of 7,500,000 shares of Class A common stock to the public at a price of $10.25 per share under the Company's registration statement on Form S-3 (the "Public Equity Offering"). The shares of Class A common stock were issued pursuant to an underwriting agreement, dated February 11, 2015, in which the Company granted the underwriters a 30-day option to purchase up to an additional 1,125,000 shares of Class A common stock.

13. Subsequent Events (Continued)

Private Placement of Class A Common Stock

On February 23, 2015, the Company completed the sale of an aggregate of $50.0 million of its Class A common stock to certain affiliates of GSO Capital Partners LP and Magnetar Capital LLC in a direct placement of registered shares under the Company's registration statement on Form S-3 (the "Private Equity Offering"). Under the terms of the Private Equity Offering, the Company sold 4,761,905 shares of Class A common stock at a purchase price of $10.50 per share.

Private Placement of Senior Unsecured Notes

On February 23, 2015, JEH and Jones Energy Finance Corp., a wholly-owned subsidiary of JEH formed for the sole purpose of co-issuing certain of JEH's debt, completed the sale of $250.0 million in aggregate principal amount of 9.25% senior unsecured notes due 2023 (the "2023 Notes") to certain affiliates of GSO Capital Partners LP and Magnetar Capital LLC in a private placement (the "Notes Offering"). The 2023 Notes rank equally with all of the Company's other senior unsecured indebtedness and are effectively subordinated in right of payment to all of the Company's secured indebtedness (to the extent of the collateral securing such indebtedness). The 2023 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Company and by all of JEH's existing subsidiaries (other than the co-issuer and two immaterial subsidiaries) and any future subsidiaries that guarantee indebtedness under the Revolver or other debt securities.

The Company used the net proceeds from the Public Equity Offering, the Private Equity Offering and the Notes Offering for working capital and to repay outstanding borrowings under the Revolver.

14. Subsidiary Guarantors

On April 1, 2014, JEH and its wholly-owned subsidiary, Jones Energy Finance Corp. (the "Issuers"), sold $500.0 million in aggregate principal amount of the Issuers' 6.75% Senior Notes due 2022 (the "2022 Notes").

The 2022 Notes are guaranteed on a senior unsecured basis by the Company and by all of JEH's current subsidiaries (except Jones Energy Finance Corp. and two immaterial subsidiaries) and certain future subsidiaries, including any future subsidiaries that guarantee any indebtedness under the Company's Revolver. Each subsidiary guarantor is 100% owned by JEH, and all guarantees are full, unconditional, and joint and several with all other subsidiary guarantees and the parent guarantee. Any subsidiaries of JEH other than the subsidiary guarantors and Jones Energy Finance Corp. are minor.

The Company is a holding company and has no independent assets or operations of its own. The Company is the sole managing member of JEH and is responsible for all operational, management and administrative decisions related to JEH's business. In accordance with JEH's limited liability company agreement, the Company may not be removed as the sole managing member of JEH.

As of December 31, 2014, the Company held approximately 25.6% of the economic interest in JEH, with the remaining 74.4% economic interest held by a group of investors that owned interests in JEH prior to the Company's IPO (the "Existing Owners"). The Existing Owners have no voting rights with respect to their economic interest in JEH.

The Company has two classes of common stock, Class A common stock, which was sold to investors in the IPO, and Class B common stock. Pursuant to the Company's certificate of

14. Subsidiary Guarantors (Continued)

incorporation, each share of Class A common stock is entitled to one vote per share, and the shares of Class A common stock are entitled to 100% of the economic interests in the Company. Each share of Class B common stock has no economic rights in the Company, but entitles its holder to one vote on all matters to be voted on by the Company's stockholders generally.

In connection with a reorganization that occurred immediately prior to the IPO, each Existing Owner was issued a number of shares of Class B common stock that is equal to the number of JEH Units that such Existing Owner holds. Holders of the Company's Class A common stock and Class B common stock generally vote together as a single class on all matters presented to the Company's stockholders for their vote or approval. Accordingly, the Existing Owners collectively have a number of votes in the Company equal to the aggregate number of JEH Units that they hold.

The Existing Owners have the right, pursuant to the terms of an Exchange Agreement by and among the Company, JEH and each of the Existing Owners, to exchange their JEH Units (together with a corresponding number of shares of Class B common stock) 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, the Company expects that over time the Company will have an increasing economic interest in JEH as Class B common stock and JEH Units are exchanged for Class A common stock. Moreover, any transfers of JEH Units outside of the Exchange Agreement (other than permitted transfers to affiliates) must be approved by the Company. The Company intends to retain full voting and management control over JEH.

Jones Energy, Inc.

Condensed Consolidating Balance Sheet

December 31, 2014

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 100	$ 1,000	$ 12,436	$ 30	$ —	$ 13,566
Restricted cash	—	—	149	—	—	149
Accounts receivable, net						
Oil and gas sales	—	—	49,861	—	—	49,861
Joint interest owners	—	—	41,761	—	—	41,761
Other	102	8,788	3,622	—	—	12,512
Commodity derivative assets	—	121,519	—	—	—	121,519
Other current assets	—	451	2,923	—	—	3,374
Intercompany receivable	4,164	1,205,608	—	(2,328)	(1,207,444)	—
Total current assets	4,366	1,337,366	110,752	(2,298)	(1,207,444)	242,742
Oil and gas properties, net, at cost under the successful efforts method	—	—	1,638,860	—	—	1,638,860
Other property, plant and equipment, net	—	—	3,252	796	—	4,048
Commodity derivative assets	—	87,055	—	—	—	87,055
Other assets	—	20,098	254	—	—	20,352
Deferred tax assets	171	—	—	—	—	171
Investment in subsidiaries	231,866	—	—	—	(231,866)	—
Total assets	$236,403	$1,444,519	$1,753,118	$(1,502)	$(1,439,310)	$1,993,228
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ —	$ 288	$ 136,049	$ —	$ —	$ 136,337
Oil and gas sales payable	—	—	70,469	—	—	70,469
Accrued liabilities	—	8,914	10,487	—	—	19,401
Deferred tax liabilities	—	718	—	—	—	718
Asset retirement obligations	—	—	3,074	—	—	3,074
Intercompany payable	—	—	1,209,630	—	(1,209,630)	—
Total current liabilities	—	9,920	1,429,709	—	(1,290,630)	229,999
Long-term debt	—	360,000	—	—	—	360,000
Senior notes	—	500,000	—	—	—	500,000
Deferred revenue	—	13,377	—	—	—	13,377
Commodity derivative liabilities	—	28	—	—	—	28
Asset retirement obligations	—	—	10,536	—	—	10,536
Liability under tax receivable agreement	803	—	—	—	—	803
Deferred tax liabilities	20,093	6,519	—	—	—	26,612
Total liabilities	20,896	889,844	1,440,245	—	(1,209,630)	1,141,355
Stockholders' / members' equity						
Members' equity	—	554,675	312,873	(1,502)	(866,046)	—
Class A common stock, $0.001 par value; 12,672,260 shares issued and 12,649,658 shares outstanding	13	—	—	—	—	13
Class B common stock, $0.001 par value; 36,719,499 shares issued and outstanding	37	—	—	—	—	37
Treasury stock, at cost; 22,602 shares	(358)	—	—	—	—	(358)
Additional paid-in-capital	177,133	—	—	—	—	177,133
Retained earnings	38,682	—	—	—	—	38,682
Stockholders' equity	215,507	554,675	312,873	(1,502)	(866,046)	215,507
Non-controlling interest	—	—	—	—	636,366	636,366
Total stockholders' equity	215,507	554,675	312,873	(1,502)	(229,680)	851,873
Total liabilities and stockholders' equity	$236,403	$1,444,519	$1,753,118	$(1,502)	$(1,439,310)	$1,993,228

Jones Energy, Inc.
Condensed Consolidating Balance Sheet
December 31, 2013

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 100	$ 6,000	$ 17,650	$ 70	$ —	$ 23,820
Restricted cash	—	—	45	—	—	45
Accounts receivable, net						
Oil and gas sales	—	—	51,233	—	—	51,233
Joint interest owners	—	—	42,481	—	—	42,481
Other	—	—	16,782	—	—	16,782
Commodity derivative assets	—	8,837	—	—	—	8,837
Other current assets	—	387	2,005	—	—	2,392
Deferred tax assets	—	12	—	—	—	12
Intercompany receivable	638	1,051,389	—		(1,052,027)	—
Total current assets	738	1,066,625	130,196	70	(1,052,027)	145,602
Oil and gas properties, net, at cost under the successful efforts method	—	—	1,297,228	—	—	1,297,228
Other property, plant and equipment, net	—	—	2,557	887	—	3,444
Commodity derivative assets	—	25,398	—	—	—	25,398
Other assets	—	14,072	934	—	—	15,006
Investment in subsidiaries	169,081	—	—	—	(169,081)	—
Deferred tax assets	1,301	—	—	—	—	1,301
Total assets	$171,120	$1,106,095	$1,430,915	$ 957	$(1,221,108)	$1,487,979
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ —	$ 230	$ 89,200	$ —	$ —	$ 89,430
Oil and gas sales payable	—	—	66,179	—	—	66,179
Accrued liabilities	87	1,642	9,076	—	—	10,805
Commodity derivative liabilities	—	10,664	—	—	—	10,664
Asset retirement obligations	—	—	2,590	—	—	2,590
Intercompany payable	—	—	1,051,935	2,279	(1,054,214)	—
Total current liabilities	87	12,536	1,218,980	2,279	(1,054,214)	179,668
Long-term debt	—	658,000	—	—	—	658,000
Deferred revenue	—	14,531	—	—	—	14,531
Commodity derivative liabilities	—	190	—	—	—	190
Asset retirement obligations	—	—	8,373	—	—	8,373
Deferred tax liabilities	—	3,093	—	—	—	3,093
Total liabilities	87	688,350	1,227,353	2,279	(1,054,214)	863,855
Stockholders' / members' equity						
Members' equity	—	417,745	203,562	(1,322)	(619,985)	—
Class A common stock, $0.001 par value; 12,526,580 shares issued and outstanding	13	—	—	—	—	13
Class B common stock, $0.001 par value; 36,836,333 shares issued and outstanding	37	—	—	—	—	37
Additional paid-in-capital	173,169	—	—	—	—	173,169
Retained earnings (deficit)	(2,186)	—	—	—	—	(2,186)
Stockholders' equity	171,033	417,745	203,562	(1,322)	(619,985)	171,033
Non-controlling interest	—	—	—	—	453,091	453,091
Total stockholders' equity	171,033	417,745	203,562	(1,322)	(166,894)	624,124
Total liabilities and stockholders' equity	$171,120	$1,106,095	$1,430,915	$ 957	$(1,221,108)	$1,487,979

Jones Energy, Inc.

Condensed Consolidating Statement of Operations and Comprehensive Income

Year Ended December 31, 2014

(in thousands)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$378,401	$ —	$ —	$378,401
Other revenues	—	1,154	1,042	—	—	2,196
Total operating revenues	—	1,154	379,443	—	—	380,597
Operating costs and expenses						
Lease operating	—	—	43,843	—	—	43,843
Production taxes	—	—	18,094	—	—	18,094
Exploration	—	—	3,453	—	—	3,453
Depletion, depreciation and amortization	—	—	181,578	91	—	181,669
Accretion of discount	—	—	770	—	—	770
General and administrative (including non-cash compensation expense)	—	4,494	21,180	89	—	25,763
Total operating expenses	—	4,494	268,918	180	—	273,592
Operating income	—	(3,340)	110,525	(180)	—	107,005
Other income (expense)						
Interest expense	—	(45,215)	(1,511)	—	—	(46,726)
Net gain on commodity derivatives	—	189,641	—	—	—	189,641
Gain on sales of assets	—	—	297	—	—	297
Other income (expense), net	—	144,426	(1,214)	—	—	143,212
Income (loss) before income tax	—	141,086	109,311	(180)	—	250,217
Equity interest in income	62,785	—	—	—	(62,785)	—
Income tax provision						
Current	53					53
Deferred	21,864	4,157				26,021
Total income tax provision	21,917	4,157	—	—	—	26,074
Net income (loss)	40,868	136,929	109,311	(180)	(62,785)	224,143
Net income attributable to non-controlling interests	—	—	—	—	183,275	183,275
Net income attributable to controlling interests	$40,868	—	—	—	—	$ 40,868

Jones Energy, Inc.

Condensed Consolidating Statement of Operations and Comprehensive Income

Year Ended December 31, 2013

(in thousands)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$258,063	$ —	$ —	$258,063
Other revenues	—	469	637	—	—	1,106
Total operating revenues	—	469	258,700	—	—	259,169
Operating costs and expenses						
Lease operating	—	—	27,781	—	—	27,781
Production taxes	—	—	12,865	—	—	12,865
Exploration	—	—	1,710	—	—	1,710
Depletion, depreciation and amortization	—	—	114,046	90	—	114,136
Impairment of oil and gas properties	—	—	14,415	—	—	14,415
Accretion of discount	—	—	608	—	—	608
General and administrative (including non-cash compensation expense)	—	4,154	27,490	258	—	31,902
Total operating expenses	—	4,154	198,915	348	—	203,417
Operating income	—	(3,685)	59,785	(348)	—	55,752
Other income (expense)						
Interest expense	—	(29,653)	(1,121)	—	—	(30,774)
Net gain (loss) on commodity derivatives	—	(2,566)	—	—	—	(2,566)
Gain (loss) on sales of assets	—	—	41	(119)	—	(78)
Other income (expense), net	—	(32,219)	(1,080)	(119)	—	(33,418)
Income (loss) before income tax	—	(35,904)	58,705	(467)	—	22,334
Equity interest in income	(3,400)	—	—	—	3,400	—
Income tax provision (benefit)						
Current	85		—	—	—	85
Deferred	(1,299)	1,143	—	—	—	(156)
Total income tax provision (benefit)	(1,214)	1,143	—	—	—	(71)
Net income (loss)	(2,186)	(37,047)	58,705	(467)	3,400	22,405
Net income attributable to non-controlling interests	—	—	—	—	24,591	24,591
Net income (loss) attributable to controlling interests	$(2,186)	—	—	—	—	$ (2,186)

Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2014

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ 40,868	$ 136,929	$ 109,311	$(180)	$(62,785)	$ 224,143
Adjustments to reconcile net income (loss) to net cash provided by operating activities	(40,510)	(326,859)	345,724	140	62,785	41,280
Net cash (used in) / provided by operations	358	(189,930)	455,035	(40)	—	265,423
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(474,619)	—	—	(474,619)
Net adjustments to purchase price of properties acquired	—	—	15,709	—	—	15,709
Proceeds from sales of assets	—	—	448	—	—	448
Acquisition of other property, plant and equipment	—	—	(1,683)	—	—	(1,683)
Current period settlements of matured derivative contracts	—	(3,654)	—	—	—	(3,654)
Change in restricted cash	—	—	(104)	—	—	(104)
Net cash (used in) / provided by investing	—	(3,654)	(460,249)	—	—	(463,903)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	170,000	—	—	—	170,000
Repayment under long-term debt	—	(468,000)	—	—	—	(468,000)
Proceeds from senior notes	—	500,000	—	—	—	500,000
Payment of debt issuance costs	—	(13,416)	—	—	—	(13,416)
Purchase of treasury stock	(358)	—	—	—	—	(358)
Net cash (used in) / provided by financing	(358)	188,584	—	—	—	188,226
Net increase (decrease) in cash	—	(5,000)	(5,214)	(40)	—	(10,254)
Cash						
Beginning of period	100	6,000	17,650	70	—	23,820
End of period	$ 100	$ 1,000	$ 12,436	$ 30	$ —	$ 13,566

Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2013

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (2,186)	$ (37,047)	$ 58,705	$(467)	$ 3,400	$ 22,405
Adjustments to reconcile net income (loss) to net cash provided by operating activities	2,286	(189,393)	315,942	733	(3,400)	126,168
Net cash (used in) / provided by operations	100	(226,440)	374,647	266	—	148,573
Cash flows from investing activities						
Investment in subsidiary	(172,481)	—	—	—	172,481	—
Additions to oil and gas properties	—	—	(197,618)	—	—	(197,618)
Acquisition of properties	—	—	(178,173)	—	—	(178,173)
Proceeds from sales of assets	—	—	963	644	—	1,607
Acquisition of other property, plant and equipment	—	—	(724)	(910)	—	(1,634)
Current period settlements of matured derivative contracts	—	7,586	—	—	—	7,586
Change in restricted cash	—	—	(45)	—	—	(45)
Net cash (used in) / provided by investing	(172,481)	7,586	(375,597)	(266)	172,481	(368,277)
Cash flows from financing activities						
Proceeds from investment in JEI	—	172,481	—	—	(172,481)	—
Proceeds from issuance of long-term debt	—	220,000	—	—		220,000
Repayment under long-term debt	—	(172,000)	—	—		(172,000)
Payment of debt issuance costs	—	(683)	—	—		(683)
Proceeds from sale of common stock, net of expenses of $15.1 million	172,481	—	—	—		172,481
Net cash (used in) / provided by financing	172,481	219,798	—	—	(172,481)	219,798
Net increase (decrease) in cash	100	944	(950)	—	—	94
Cash						
Beginning of period	—	5,056	18,600	70	—	23,726
End of period	$ 100	$ 6,000	$ 17,650	$ 70	$ —	$ 23,820

Jones Energy, Inc.
Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Costs Incurred

Costs incurred for oil and gas property acquisitions, exploration and development for the last three years are as follows:

(in thousands)	2014	2013	2012
Property acquisitions:			
Unproved	$ 20,030	$ 35,943	$ 69,725
Proved	10,101	142,230	182,200
Exploration	3,453	1,710	356
Development	488,076	240,412	125,493
Asset retirement costs	1,908	1,822	662
Total costs incurred	$523,568	$422,117	$378,436

Capitalized Costs

Capitalized costs for our oil and gas properties consisted of the following at the end of each of the following years:

(in thousands)	2014	2013
Unproved properties	$ 94,526	$ 99,134
Proved properties	2,095,396	1,568,564
	2,189,922	1,667,698
Accumulated depletion and impairment	(551,062)	(370,470)
Net capitalized costs	$1,638,860	$1,297,228

Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and gas reserves (including natural gas liquids) is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur from time to time.

The following tables set forth the Company's total proved reserves and the changes in the Company's total proved reserves. These reserve estimates are based in part on reports prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), independent petroleum engineers, utilizing data compiled by us. In preparing its reports, Cawley Gillespie evaluated properties representing all of the Company's proved reserves at December 31, 2014, 2013 and 2012. The Company's proved reserves are located onshore in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of natural gas, natural gas liquids and oil that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in future years from known oil and natural gas reservoirs under existing economic conditions, operating methods and government regulations at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2011	7,440	34,606	244,579	82,810
Extensions and discoveries	286	1,766	11,727	4,007
Production	(742)	(1,770)	(13,980)	(4,842)
Purchases of minerals in place	6,056	5,799	36,842	17,995
Sales of minerals in place	(8)	(53)	(309)	(113)
Revisions of previous estimates	(492)	(5,602)	(50,779)	(14,557)
December 31, 2012	12,540	34,746	228,080	85,300
Extensions and discoveries	3,786	5,710	39,799	16,129
Production	(1,557)	(1,724)	(17,575)	(6,210)
Purchases of minerals in place	3,275	4,418	35,023	13,530
Sales of minerals in place	—	—	583	97
Revisions of previous estimates	(1,356)	(10,235)	(49,262)	(19,801)
December 31, 2013	16,688	32,915	236,648	89,045
Extensions and discoveries	9,295	8,675	59,248	27,844
Production	(2,475)	(2,345)	(21,922)	(8,474)
Purchases of minerals in place	3,180	3,073	22,943	10,077
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	995	(3,448)	(4,640)	(3,226)
December 31, 2014	27,683	38,870	292,277	115,266

Revision of previous estimates

For the year ended December 31, 2014, the Company had net negative revisions of 3,226 MBoe, of which 3,534 MBoe was related to production performance in the Woodford basin. The remaining net positive revisions of 308 MBoe were primarily related to production performance in the Cleveland basin and other changes.

For the year ended December 31, 2013, the Company had net negative revisions of 19,801 MBoe, of which 15,518 MBoe was related to the expiration of the Company's JDA with Southridge. The remaining net negative revisions of 4,283 MBoe were due to a combination of production performance in the Cleveland and Woodford, prices and other changes.

For the year ended December 31, 2012, the Company had net negative revisions of 14,557 MBoe primarily due to the removal of certain proved undeveloped reserves in the Atoka formation, production performance in the Woodford formation and decreased gas prices in the Cleveland.

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2012				
Proved developed	4,262	16,320	110,956	39,075
Proved undeveloped	8,278	18,426	117,124	46,225
Total proved reserves	12,540	34,746	228,080	85,300
December 31, 2013				
Proved developed	7,129	19,101	139,623	49,501
Proved undeveloped	9,559	13,814	97,025	39,544
Total proved reserves	16,688	32,915	236,648	89,045
December 31, 2014				
Proved developed	10,773	22,555	160,877	60,141
Proved undeveloped	16,910	16,315	131,400	55,125
Total proved reserves	27,683	38,870	292,277	115,266

(1) Barrels of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or natural gas liquids.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by FASB Accounting Standards Codification Topic 932, *Extractive Industries—Oil and Gas* (Topic 932). The "standardized measure of discounted future net cash flows" should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance.

In reviewing the information that follows, the following factors should be taken into account:

- future costs and sales prices will probably differ from those required to be used in these calculations;
- actual production rates for future periods may vary significantly from the rates assumed in the calculations;
- future tax rates, deductions and credits are calculated under current laws, which may change in future years;
- a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and natural gas revenues.

Under the standardized measure, future cash inflows were estimated by using the average of the historical unweighted first-day-of-the-month prices of oil and natural gas for the prior twelve month periods ended December 31, 2014, 2013 and 2012. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by estimated future development and production costs based on year-end costs in order to arrive at net cash flows. Use of a 10% discount rate, first-day-of-the-month prices and year-end costs are required by ASC 932.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

The standardized measure of discounted future net cash flows from the Company's estimated proved oil and natural gas reserves follows:

(in thousands)	2014	2013	2012
Future cash inflows	$ 5,038,212	$3,213,718	$2,746,767
Less related future:			
Production costs	(1,216,184)	(734,974)	(612,054)
Development costs	(939,652)	(549,343)	(529,692)
Income tax expense	(199,727)	(129,497)	—
Future net cash flows	2,682,649	1,799,904	1,605,021
10% annual discount for estimated timing of cash flows	(1,294,553)	(859,395)	(823,001)
Standardized measure of discounted future net cash flows	$ 1,388,096	$ 940,509	$ 782,020

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved natural gas and crude oil reserves follows:

(in thousands)	2014	2013	2012
Balance, beginning of period	$ 940,509	$ 782,020	$ 915,807
Net change in sales and transfer prices, net of production expenses	98,647	77,280	(336,855)
Changes in estimated future development costs	(96,245)	(9,706)	67,495
Sales and transfers of oil and gas produced during the period	(382,202)	(224,739)	(119,931)
Net change due to extensions and discoveries	442,340	239,844	37,723
Net change due to purchases of minerals in place	118,562	149,619	197,740
Net change due to sales of minerals in place	—	(337)	(1,578)
Net change due to revisions in quantity estimates	43,032	(168,438)	(144,901)
Previously estimated development costs incurred during the period	163,739	110,783	99,513
Net change in income taxes	(36,514)	(76,965)	—
Accretion of discount	94,051	59,621	91,581
Other	2,177	1,527	(24,574)
Balance, end of period	$1,388,096	$ 940,509	$ 782,020

Supplemental Quarterly Financial Information (Unaudited)

Restatement of Previously Issued Unaudited Quarterly Financial Statements

As part of our fourth quarter closing procedures, we identified an error in our previously issued 2014 quarterly financial statements which would have been material to such statements if not restated. Therefore we have restated our Supplemental Quarterly Financial Information for the quarters ended March 31, 2014, June 30, 2014 and September 30, 2014 as a result of an error in the calculation of depletion, depreciation and amortization included in Jones' consolidated financial statements. The Company inadvertently classified capital expenditures related to nine new wells as Arkoma assets rather than Anadarko assets leading to a miscalculation of depletion rates. This incorrect classification resulted in the understatement of depletion, depreciation and amortization expense and the overstatement of oil and gas properties in the amount of $1.9 million, $2.5 million and $2.6 million for the quarters ended March 31, 2014, June 30, 2014 and September 30, 2014, respectively. As a result, net income (loss) decreased for the quarters ended March 31, 2014, June 30, 2014 and September 30, 2014 by $1.7 million, $2.3 million, and $2.2 million, respectively. The balance sheet restatement resulted in increases in accumulated depletion in the same amounts for each of the same periods. These restatements had no impact on our net cash provided by operations in our Consolidated Statement of Cash Flows. Restatements to the three month period ended March 31, 2014, the three and six month periods ended June 30, 2014 and the three and nine month periods ended September 30, 2014 will be made when they are next filed in the Company's quarterly financial statements on Form 10-Q for the quarters ending March 31, 2015, June 30, 2015 and September 30, 2015, respectively.

The impact of the restatement will be noted in Form 10-Q filings for 2015 and is summarized in the table below:

	2014 Three Months Ended					
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
(in thousands)	First Quarter	First Quarter	Second Quarter	Second Quarter	Third Quarter	Third Quarter
Oil and gas properties	$1,363,393	$1,361,538	$1,449,765	$1,445,322	$1,533,704	$1,526,735
Depletion, depreciation and amortization	$ 39,345	$ 41,200	$ 43,211	$ 45,799	$ 47,965	$ 50,491
Operating income	$ 35,872	$ 34,017	$ 38,702	$ 36,114	$ 28,757	$ 26,231
Net income (loss)	$ 9,388	$ 7,708	$ (9,184)	$ (11,455)	$ 52,230	$ 50,024
Net income (loss) attributable to non-controlling interests	$ 7,715	$ 6,339	$ (7,537)	$ (9,398)	$ 42,701	$ 40,893
Net income (loss) attributable to controlling interests	$ 1,673	$ 1,369	$ (1,647)	$ (2,057)	$ 9,529	$ 9,131
Basic earnings per share	$ 0.13	$ 0.11	$ (0.13)	$ (0.16)	$ 0.76	$ 0.73
Diluted earnings per share	$ 0.13	$ 0.11	$ (0.13)	$ (0.16)	$ 0.76	$ 0.73

The calculations of EBITDAX included in the Company's previously filed consolidated financial statements for the first three quarters of 2014 remain unchanged as a result of the restatements set forth herein.

Following is a summary of the Company's results of operations by quarter for the years ended December 31, 2014 and 2013.

(in thousands except per share data)	2014 (Restated) First Quarter	(Restated) Second Quarter	(Restated) Third Quarter	Fourth Quarter	Full Year
Revenues	$98,244	$106,390	$100,346	$ 75,617	$380,597
Operating income	34,017	36,114	26,231	10,643	107,005
Net income (loss)	7,708	(11,455)	50,024	177,866	224,143
Net income (loss) attributable to non-controlling interests	6,339	(9,398)	40,893	145,441	183,275
Net income (loss) attributable to controlling interests	1,369	(2,057)	9,131	32,425	40,868
Basic earnings per share	$ 0.11	$ (0.16)	$ 0.73	$ 2.58	$ 3.26
Diluted earnings per share	$ 0.11	$ (0.16)	$ 0.73	$ 2.58	$ 3.26

(in thousands except per share data)	2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$55,480	$64,526	$ 68,851	$70,312	$259,169
Operating income	18,047	20,251	12,095	5,359	55,752
Net income (loss)	(1,452)	48,417	(15,483)	(9,077)	22,405
Net income (loss) attributable to non-controlling interests			(14,623)	(7,751)	24,591
Net loss attributable to controlling interests			(860)	(1,326)	(2,186)
Basic earnings (loss) per share			$ (0.07)	$ (0.10)	$ (0.17)
Diluted earnings (loss) per share			$ (0.07)	$ (0.10)	$ (0.17)

FORWARD-LOOKING STATEMENT

This annual report contains 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. All statements, other than statements of historical fact, included in this annual report that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this annual report specifically include the expectations of plans, strategies, objectives and anticipated operating results of the Company, including guidance regarding the Company's drilling program and ability to achieve favorable pricing for future acquisitions. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements and are described in further detail in the Company's Annual Report on Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

MANAGEMENT

JONNY JONES
Founder, Chairman
& Chief Executive Officer

MIKE S. MCCONNELL
President

ROBERT J. BROOKS
Executive Vice President
& Chief Financial Officer

ERIC NICCUM
Executive Vice President
& Chief Operating Officer

KRISTEL FRANKLIN
Sr. Vice President – Resources

HAL HAWTHORNE
Sr. Vice President – New Ventures

STEPHEN ROBERTS
Sr. Vice President – Drilling
& Completions

JEFF TANNER
Sr. Vice President – Geosciences

TODD WEHNER
Sr. Vice President
& Chief Accounting Officer

DAVID CAPE
VP – Land and Business Development

DENNIS CORKRAN
VP – Production, Operations, and HSE

THOMAS HESTER
VP – Finance

BOARD OF DIRECTORS

JONNY JONES
Chairman

ALAN D. BELL
Director

HOWARD I. HOFFEN
Director

MIKE S. MCCONNELL
Director

GREGORY D. MYERS
Director

ROBB L. VOYLES
Director

HAL WASHBURN
Director

CORPORATE HEADQUARTERS

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TRANSFER AGENT

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Brooklyn, NY 11219
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STOCK EXCHANGE

Common stock traded on the New York Stock Exchange under the symbol: JONE

FORM 10-K

For an additional copy of the Annual Report on Form 10-K, please contact:

JONES ENERGY, INC.
Investor Relations Department
Phone: 512.328.2953
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WEBSITE ADDRESS

www.jonesenergy.com

ANNUAL MEETING

The Annual Meeting for Jones Energy, Inc. shareholders will be held at our corporate headquarters in Austin, Texas on May 28, 2015.

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