Jones Energy, Inc.
Form 8-K
February 05, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)

of the Securities Exchange Act of 1934

Date of Report (date of earliest event reported): **February 5, 2018**

Jones Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**001-36006**	**80-0907968**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

807 Las Cimas Parkway, Suite 350 **Austin, Texas**	**78746**
(Address of Principal Executive Offices)	(Zip Code)

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

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR 230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR 240.12b-2).

Emerging growth company x

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. x

Item 2.02 Results of Operations and Financial Condition

The matters set forth in Item 7.01, to the extent they relate to results of operations and financial condition, are incorporated by reference in this Item 2.02.

Item 7.01 Regulation FD Disclosure.

The information disclosed in this Item 7.01, including Exhibit 99.1, Exhibit 99.2 and Exhibit 99.3 hereto, is being furnished and shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), or otherwise subject to the liabilities under that section, nor shall they be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended (the Securities Act), or the Exchange Act except as expressly set forth by specific reference in such filing.

On February 5, 2018, Jones Energy, Inc., a Delaware corporation (the Company), issued a press release announcing an operations update, 2017 year-end reserves and 2018 guidance. A copy of the press release is attached hereto as Exhibit 99.1 and is incorporated by reference.

In addition, on February 5, 2018 the Company issued a press release announcing a private offering (the Offering) of $450 million of senior secured first lien notes due 2023 (the notes) issued by Jones Energy Holdings, LLC and Jones Energy Finance Corp., both subsidiaries of the Company. The offering is being made to persons reasonably believed to be qualified institutional buyers as defined in Rule 144A under the Securities Act and in offshore transactions pursuant to Regulation S under the Securities Act. A copy of the press release is attached hereto as Exhibit 99.2 and is incorporated by reference.

Certain information contained in the preliminary offering circular, dated February 5, 2018, relating to the Offering (the Offering Circular) is set forth in this report below.

Unless indicated otherwise in this Current Report on Form 8-K (this 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 LLC) and Jones Energy Finance Corp., and, when used in discussions of the notes, refer only to JEH LLC and Jones Energy Finance Corp. As the sole managing member of JEH LLC, Jones Energy, Inc. is responsible for all operational, management and administrative decisions relating to JEH LLC s business and consolidates the financial results of JEH LLC and its subsidiaries. As a result, all financial and operating data presented in this Report are those of Jones Energy, Inc. on a consolidated basis. References to the Issuers refer to JEH LLC and Jones Energy Finance Corp., and references to JONE refer solely to Jones Energy, Inc. and not any of its subsidiaries. References to the Guarantors refer collectively to Jones Energy, Inc., Nosley Assets, LLC, Jones Energy, LLC, Nosley SCOOP, LLC and Nosley Acquisition, LLC. Jones Energy, Inc. is a holding company whose sole material asset is an equity interest in Jones Energy Holdings, LLC. The estimates of our reserves included in this Report or incorporated by reference as of December 31, 2015, 2016 and 2017 are based on reserve reports prepared for Jones Energy by Cawley, Gillespie & Associates, Inc., independent petroleum engineers (Cawley Gillespie). For the definitions of certain terms and abbreviations used in the oil and natural gas industry, see Glossary of Oil and Natural Gas Terms.

On August 1, 2017, JEH LLC sold its Arkoma Basin properties (the Arkoma Assets). Operating data for the twelve months ended December 31, 2017 includes the Arkoma Assets,

however, reserve and operating data as of December 31, 2017 and for the three months ended December 31, 2017 presented in this Report do not include the Arkoma Assets.

Operations Update

As of December 31, 2017, our total estimated proved reserves were 104.8 MMBoe, of which 59% were classified as proved developed reserves. Approximately 28% of these total estimated proved reserves consisted of oil, 32% consisted of NGLs, and 41% consisted of natural gas. As of December 31, 2017, our total estimated probable reserves were 109.7 MMBoe and our total estimated possible reserves were 325.8 MMBoe.

During the year ended December 31, 2017, our properties included 1,044 gross producing wells. For the three years ended December 31, 2017, we drilled 142 wells in the Western Anadarko Basin and 26 wells in the Merge.

The following tables presents summary reserve and production data for each of our core operating areas. For additional information relating to our estimated oil and natural gas reserves, please see Summary Historical Reserve and Operating Data, Risk Factors and Cautionary Statement Regarding Forward Looking Statements. For more information regarding probable and possible reserves, see Summary Historical Reserve and Operating Data and Exhibit 99.3.

	As of December 31, 2017					
	Eastern Anadarko(1)		Western Anadarko(2)		Total(3)(4)	
	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)
PDP	8.6	88.5	45.5	334.9	54.1	423.4
PDNP	5.4	55	2.7	7.9	8.1	62.9
PUD	14.3	83.3	28.3	57.0	42.6	140.3
Total Reserves	28.3	226.8	76.5	399.8	104.8	626.6
Probable	90.4	460.9	19.3	10.8	109.7	471.7
Possible	240.6	788.2	85.2	130.2	325.8	918.4

	As of December 31, 2016					
	Eastern Anadarko(1)		Western Anadarko(2)		Total(3)(4)	
	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)	Net Reserves (MMBoe)	SEC PV-10(1) ($MM)
PDP	0.6	4.0	57.8	335.7	58.4	339.6
PDNP			4.1	20.5	4.1	20.6
PUD	1.8	4.3	41.0	36.9	42.7	41.2
Total Reserves	2.4	8.3	102.8	393.0	105.2	401.4

(1) Eastern Anadarko consists of the Merge.

(2) Western Anadarko includes the Cleveland, Granite Wash, Tonkawa and Marmaton formations.

(3) Total includes the Eastern Anadarko, Western Anadarko and our other reserves.

(4) GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for proved, probable or possible reserves calculated using prices other than SEC prices. SEC PV-10 does not take into account the effect of future taxes, and SEC PV-10 estimates for reserve categories other than proved or for pricing sensitivities uses the relevant reserve volumes and prices, as applicable, but SEC PV-10 is otherwise calculated using the same assumptions as those for, and in a manner consistent with, the calculation of standardized measure. Because SEC PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized measure of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Similarly, SEC PV-10 estimates for price sensitivities are not adjusted for the likelihood that the relevant pricing scenario will occur, and thus they may be subject to the same issues with comparability. Nonetheless, we believe that SEC PV-10 estimates for reserve categories other than proved or for pricing sensitivities present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, SEC PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Investors should be cautioned that neither SEC PV-10 nor standardized measure represents an estimate of the fair market value of our proved reserves. In addition, investors should be further cautioned that estimates of SEC PV-10 of probable reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Further, because estimates of probable and possible reserve volumes and SEC PV-10 have not been adjusted for risk due to this uncertainty of recovery, they should not be summed arithmetically with each other or with comparable estimates for proved reserves. GAAP does not prescribe any corresponding measure for SEC PV-10 of probable reserves and possible reserves or reserves based on other than SEC prices. As a result, it is not practicable for us to reconcile these additional SEC PV-10 measures to GAAP standardized measure. For a definition of the non-GAAP financial measure PV-10 and a reconciliation of our GAAP standardized measure of discounted future net cash flows to PV-10, please see Summary Historical Reserve and Operating Data Reconciliation of PV-10 to Standardized Measure.

	Quarter Ended December 31, 2017 Average Daily Net Production		Year Ended December 31, 2017(1) Average Daily Net Production	
	MBoe/d	% Oil and NGLs	MBoe/d	% Oil and NGLs
Eastern Anadarko	5.0	60%	2.8	61%
Western Anadarko	15.0	61%	15.2	60%
Other	1.2	36%	3.3	35%
All Properties	21.2	59%	21.3	56%

(1) Includes production relating to the Arkoma Assets, which were sold on August 1, 2017.

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

	As of December 31, 2017					
	Acreage		Producing Wells		Identified Drilling Locations(1)(2)	
	Gross	Net	Gross	Net	Gross	Net
Eastern Anadarko	126,838	22,484	69	14	5,443	927
Western Anadarko	214,763	152,191	944	571	1,737	893
Other	33,508	18,894	31	6		
All properties	375,109	193,569	1,044	591	7,180	1,820

(1) Our total identified drilling locations include 3,499 gross total proved undeveloped, probable and possible drilling locations, of which 348 gross locations are associated with proved undeveloped reserves as of December 31, 2017. 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 in our Annual Report on Form 10-K for the year ended December 31, 2016 for more information regarding the processes and criteria through which these drilling locations were identified.

(2) Internal estimates based on horizontal development employing lateral drilling lengths of approximately 4,500 feet and well spacing of approximately 1,320-1,760 feet for Merge proved, probable and possible reserve locations, 660-880 feet for additional Merge resource locations (which are locations relating to reserves that are less likely to be recovered than possible reserves) and 1,056-1,760 feet for Western Anadarko locations.

Merge Entry and Development

In September 2016, we acquired approximately 18,000 net acres in the Merge, representing our first acquisition of properties in the STACK/SCOOP. Since then, we have acquired approximately 4,500 net acres, including approximately 3,000 net acres acquired in 2017, bringing our total Merge net acreage to approximately 22,500 (the Merge Assets). As of February 1, 2018, we have drilled 31 wells, with 10 completed in the Woodford, 15 completed in the Meramec and six drilled and awaiting completion.

As of January 31, 2018, our current production in the Merge was 2,075 Bbl/d of oil, 12,233 Mcf/d of natural gas and 1,778 Bbl/d of NGLs, for a total of 5,892 Boe/d. The following table sets forth certain information related to all of the wells we have drilled and completed in the Merge that have achived peak 30 day initial production rates (IP), except as noted below. In addition, as of February 1, 2018 we had completed 10 wells in the Merge that have not yet achieved peak 30 day IP.

	Date of First Production	Lateral Length (feet)	Peak 24 Hour IP (Boe/d)(2)	Peak 24 Hour IP % Oil	Peak 30 Day IP (Boe/d)(2)	Peak 30 Day IP % Oil
Meramec						
Bomhoff 2H	5/30/2017	4,428	2,050	32%	1,609	34%
Garrett 1H	6/24/2017	4,697	1,317	53%	1,202	51%
Nola 1H	8/1/2017	4,576	1,346	20%	1,202	20%
Hardesty 1H	10/17/2017	4,586	979	46%	796	39%
Rosewood 1H	10/19/2017	4,579	1,363	40%	1,234	38%
Rosewood 2H	10/20/2017	4,586	1,615	36%	1,483	35%
Hasten 1H	10/25/2017	4,476	1,249	41%	1,004	32%
Bone 2H (1)	12/14/2017	4,375	1,878	54%	1,665	50%
Average		4,538	1,475	40%	1,274	37%
Woodford						
Bennett 1H	3/18/2017	4,346	327	31%	285	25%
Hardy 1H	3/18/2017	4,370	619	55%	474	52%
Belyeu 1H	4/8/2017	4,895	375	83%	185	76%
Bomhoff 1H	5/28/2017	4,196	1,110	25%	941	25%
Hardesty 2H	10/22/2017	4,362	1,011	48%	549	50%
Rosewood 3H	10/22/2017	4,382	970	42%	878	40%
Bone 1H (1)	12/24/2017	4,322	755	63%	564	63%
Average		4,410	738	50%	554	47%

(1) These wells have achieved peak 30 day oil IP but have not yet achieved peak 30 day natural gas IP.

(2) Reported on a 3-stream basis, including oil, natural gas and NGLs.

We constantly seek to refine our geologic view of the Woodford and Meramec formations and drilling and completion techniques to improve well performance and repeatability. Having analyzed and mapped over 3,000 well logs and multiple cores in the Merge, our technical team has developed a deep geologic understanding of the Woodford and Meramec formations in the Merge. Further, our team has developed a proprietary petrophysical model to high-grade drilling locations and identify the most productive landing points within each formation, which we believe is paramount to maximizing development success. We believe that industry activity in the Merge, which increased from three rigs to 24 rigs over the last 24 months, will continue to increase in 2018. As we continue to collect and analyze more industry data, we believe our understanding of the reservoir and the optimal method to drill and complete wells in each respective formation will continue to grow.

In order to optimize the development of the Merge Assets and the financing thereof, under the indenture governing the notes offered hereby, we will have the flexibility to unrestrict our subsidiaries that hold the Merge Assets. Consequently, upon becoming unrestricted these subsidiaries will not be subject to many of the terms of the indenture governing the notes, and the Merge Assets will not constitute collateral under the indenture or the related security documents, although the equity of the subsidiaries that hold the Merge Assets will be pledged as collateral. In addition, the terms of the indenture will limit the ability of such subsidiaries to (a) incur certain types of indebtedness, (b) secure such indebtedness with the Merge Assets, (c) sell the Merge Assets without using the proceeds in certain ways and (d) sell equity of these subsidiaries to third parties.

Business Strategies

Our goal is to increase stakeholder value by managing our capital expenditures and level of activity to maximize returns through commodity price cycles while also evaluating and executing opportunities for growth of reserves, production, and cash flow through development and delineation of our assets, potential partnerships, acquisitions, leasing and pooling opportunities. We seek to achieve this goal by executing a combination of the following strategies:

Continue to Reduce Our Development and Operational Costs.

Decades of experience in the mid-continent United States 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, from 2005 to 2017, we reduced our spud to rig release time from 30 days to 16 days. This reduction translates into significant cost savings; reducing one day of drill time in the Cleveland currently saves an average of approximately $20,000. We are now successfully applying to the Merge the expertise in drilling efficiency gained through this experience in the Cleveland. During 2017, we reduced our drilling days in the Merge from 25 days to an average of approximately 12 days. The reduction in drill time translates into significant cost savings; reducing one day of drill time in the Merge currently saves an average of approximately $45,000. We will continue to apply this expertise while also leveraging our large-scale acreage position in the Merge 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 may give us an advantage over other operators as we compete for acquisitions, leases, and strategic partnerships.

Maintain Operational Control.

We operate substantially all of the wells that we drilled and completed during 2017, allowing us to effectively manage the timing and levels of our development spending, overall well costs and operating expenses. With over 81% of our total acreage held by existing production (85% if excluding the Merge), we will not be required to spend significant capital to hold acreage outside of the Merge. We believe that continuing to exercise a high degree of control over our acreage position will provide us with flexibility to manage the timing and level of our drilling program and optimize our returns and profitability.

Develop Our Multi-Year Inventory.

We aim to grow production and reserves through the development of our existing drilling inventory, which we believe to be relatively repeatable and low-risk. The Company has a long history in the mid-continent United States, having drilled over 930 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, 2017, we had identified 7,180 gross (1,820 net) drilling locations, which gives us many years of potential development drilling based on our current development plan.

Grow Production and Reserves Through Capital Efficient Development of our Assets and Strategic Partnerships.

We are focused on growing our reserves and production at a measured pace through a capital efficient development plan. We believe that our inventory of drilling locations in the Merge, coupled with our technical understanding of the geology of the play, will allow us to develop our acreage in a cost effective manner. As we continue to increase the levels of recovery and repeatability in our Merge acreage position we expect to increase production, reserves and cash flow.

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 2017, we leased and/or acquired a total of over 11,800 net acres.

Additionally, joint development opportunities complement our acquisition strategy by reducing both risk and our capital commitment associated with drilling on acquired acreage. As previously announced, we are working with Tudor, Pickering, Holt & Co. to evaluate potential drilling joint ventures, or DrillCo, alternatives, which, if consummated, would enable the continued development of our Western Anadarko properties and add new reserves in a capital efficient manner.

Expand Inventory and Resource Potential on Existing Asset Base.

The stacked reservoirs within our asset base provide exposure to additional upside potential. In our Merge acreage, we believe we have additional upside potential beyond the Woodford and Meramec formations, including the Hunton, Osage, Chester, Caney, and Springer formations, along with numerous prospective Pennsylvanian-age sandstone and carbonate reservoirs identified from logs and offset production data. Additionally, we and other operators in the Merge are experimenting with tighter downspacing; our current inventory of locations is based on 14 wells per section and we and other nearby operators are currently testing 31 wells per section. We believe that both the delineation of additional horizons and potentially tighter downspacing will be accretive to inventory and asset value.

While our current focus is on the efficient development of our Merge Assets, we may from time to time engage in additional development activity throughout the Anadarko Basin. In the Western Anadarko Basin, we believe that we have over 740 gross potential drilling locations in the Tonkawa and Marmaton formations that provide us with development resource potential. Further, our current leasehold position provides longer term potential exposure to other prospective formations found in the Western Anadarko Basin, including the Douglas, Cottage Grove, Cherokee Shale, Atoka Shale, and the Upper, Middle and Lower Morrow formations.

Increase the Liquids Content of our Production Mix.

As we continue to focus on development in the Merge, we have increased the liquids content of our overall production mix. We have further increased the percentage of oil we produce by selling the Arkoma Assets in 2017. The overall increase in liquids rich production has increased well economics due to the relatively higher margin on liquids production versus natural gas. In 2017, approximately 56% of our production was attributable to oil and NGLs, compared to 55% in 2016.

Enhance Liquidity and Financial Flexibility.

We intend to use cash on hand, combined with cash flow from operations and the net proceeds remaining after the retirement of certain existing indebtedness, to continue executing a development plan that we believe will achieve steady growth for production, cash flow and proved reserves. We believe that this growth will enable the Company to reduce the amount of its indebtedness over time. We expect to continue to utilize a hedging strategy that will provide stability of near term cash flows and a predictable margin on our production. In 2017 we sold our Arkoma Assets for approximately $65 million which further enhanced our liquidity in line with our objective of delevering over time. We will continue to seek opportunities to reduce leverage through non-core asset sales, liability management and capital market activities. This offering will provide additional liquidity and enhance our flexibility to pursue our development plan in the Merge and to pursue opportunities to reduce our leverage.

Competitive Strengths

Geographic Focus in the Prolific Mid-Continent United States.

Our operations are focused in the mid-continent United States region, targeting liquids-rich opportunities in the Anadarko Basin of Oklahoma and Texas. 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 overlayed with well-developed natural gas and liquids midstream infrastructure and served by numerous oilfield services providers, which we believe reduces the risk of production delays and facilitates adequate takeaway capacity.

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

Our drilling inventory consists of approximately 7,180 gross identified drilling locations in the Anadarko Basin, and our development plans target locations that we believe provide attractive economics, present low risk, and support a relatively predictable production profile. As of December 31, 2017, we had identified 5,443 gross drilling locations in the Eastern Anadarko Basin and 1,737 gross drilling locations in the Western Anadarko Basin. In the Eastern Anadarko Basin, we have built a large-scale acreage position through the acquisition of approximately 18,000 net acres in September 2016, representing our first acquisition of properties in the STACK/SCOOP, and through the subsequent acquisition of approximately 4,500 net acres, bringing our total Merge net acreage to approximately 22,500. We have also expanded our drilling inventory in the Western Anadarko Basin, in prior years, through joint development agreements with large independent producers and major oil and gas companies.

Extensive Operational Expertise and Low-Cost Operating Structure.

Drilling horizontal wells has been our primary approach to field development since 1998. Having drilled more than 750 horizontal wells in eleven 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. Each day of drill time saved in the Merge currently saves us an average of approximately $45,000, and during 2017 we have reduced our drilling days in the region by 13 days. We drilled the fastest well in our history during the fourth quarter of 2017. Through our focus on drilling, completion and operational efficiencies, we are able to effectively control costs and deliver attractive rates of return and profitability.

High Caliber Management Team.

Our executive management team has over 100 years of combined industry experience across multiple disciplines including geoscience, land, and finance. We have assembled a staff of geoscientists, field operations managers and engineers with significant experience drilling horizontal wells and with fracture stimulation of unconventional formations. 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 executive management team have previously held positions with both major and large independent oil and natural gas companies, including ExxonMobil, BP, Shell, Southwestern Energy, Noble Energy, and Cabot Oil & Gas.

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 1920s. Jones family members and our management team controlled approximately 13.1% of our combined voting power and economic interest as of December 31, 2017. 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

Preliminary Estimates of Selected Fourth Quarter 2017 Financial and Operating Results

Fourth Quarter 2017 Financial Update.

Total operating revenues for the three months ended December 31, 2017 are expected to be between $52 million and $57 million, compared to $39.5 million for the three months ended December 31, 2016.

Operations Update.

Average daily net production for the three months ended December 31, 2017 was 21.2 Mboe/d. During the fourth quarter of 2017, we spud nine wells and completed 10 wells in the Merge. As of February 1, 2018, we had spud a total of 31 wells, drilled 29 wells to total depth, and placed 23 wells on production in the Merge. Fourth quarter Merge production averaged 5.0 Mboe/d, of which 60% was liquids. As of January 31, 2018, we were running two rigs in the Merge and producing 5.9 Mboe/d, of which 65% was liquids.

During the fourth quarter of 2017, we spud one well and completed a total of 15 wells in the Western Anadarko Basin. Average daily net production in the Western Anadarko Basin was 15.0 MBoe/d in the fourth quarter of 2017. In October 2017, we released our last remaining rig in the Western Anadarko Basin.

Preliminary Estimates.

The preliminary estimated financial information included in this Report has been prepared by, and is the responsibility of, our management. Our management believes that the certain key financial results for the three months ended December 31, 2017 have been prepared on a reasonable basis, reflecting the best estimates and judgments, and represent, to the best of management s knowledge and opinion, its expected financial performance for the three months ended December 31, 2017. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results.

PricewaterhouseCoopers LLP has not examined, compiled, performed, audited or reviewed any procedures with respect to the preliminary estimated financial information contained herein and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance on such information or its achievevability. PricewaterhouseCoopers LLP assumes no responsibility for and denies any association with the estimated financial information. The PricewaterhouseCoopers LLP reports incorporated by reference in this Report refer exclusively to our historical financial information. PricewaterhouseCoopers LLP reports do not cover any other information in this offering and should not be read to do so.

We do not undertake any obligation to publicly release the results of any future revisions we may make to our financial estimate or to update this financial estimate or the assumptions used to prepare the preliminary estimates to reflect events or circumstances after the completion of this offering. Our estimated results for this period are not necessarily indicative of the results that should be expected for a full fiscal year. Accordingly, you should not place undue reliance on these preliminary estimated fourth quarter results. The above are our preliminary estimates for certain key financial and operating results for the three months ended December 31, 2017.

We have prepared these estimates on a basis materially consistent with our historical financial and operating results. These estimated ranges are preliminary and unaudited and are thus inherently uncertain and subject to change. During the course of the preparation of our consolidated financial statements and related notes for inclusion in our Annual Report on Form 10-K for the year ended December 31, 2017, we may identify items that could cause our final reported results to be different from the preliminary financial estimates presented herein. Important factors that could cause actual results to differ from our preliminary estimates are set forth under the headings Risk Factors and Cautionary Statement Regarding Forward-Looking Statements.

Liquidity and Capital Resources

As of December 31, 2017, we had a cash balance of $19.5 million and $139.0 million in available borrowings under our Revolving Credit Facility. As discussed below, we intend to use a portion of the net proceeds from this offering to partially repay borrowings under our Revolving Credit Facility and reduce our borrowing base to $50.0 million. Our Revolving Credit Facility matures in November 2019.

Our 2017 capital expenditures totaled $248.0 million (excluding the impact of asset retirement costs), of which $205.7 million was utilized to drill and complete operated wells. The Company has established an initial capital budget of $150 million for 2018, including $134 million for drilling and completing wells and $16 million for leasing, workovers and other capital projects. The initial budget for 2018 in the Merge is based on estimated ranges of well costs between $5.4 million and $6.1 million per well in the Meramac and estimated well costs between $5.5 million and $6.0 million in the Woodford. We expect to fund our 2018 budgeted capital expenditures with cash flow from operations and a portion of the net proceeds from the sale of notes offered hereby, as well as potential non-strategic asset sales or potentially accessing the debt and/or equity capital markets. In addition, we may, from time to time and subject to our assessment of market conditions, engage in liability management transactions in an effort to reduce indebtedness.

We have allocated our 2018 capital expenditure budget as follows:

(in millions of dollars)		
Drilling and completion		
Eastern Anadarko, operated	$	108
Eastern Anadarko, non-operated		15
Western Anadarko		11
Total drilling and completion	$	134
Other		16
All properties and activities	$	150

We consider projections of future commodity prices when determining our development plan, but many other factors are also considered. Should the commodity price environment or other of these factors vary from current levels, we will re-evaluate our development plan at that time. If the evaluation results in a shifting of capital expenditures into future periods beyond five years from the initial proved reserve booking, it could potentially lead to a reduction in proved undeveloped reserves.

2018 Outlook

In 2018, we are focusing the majority of our capital budget and resources on the development of our high-return Merge asset, where we have an inventory of over 5,443 gross (927 net) operated drilling locations, or over 25 years of drilling inventory at our current two-rig pace. We believe the recognized value of the Merge will continue to improve as we and other operators in the area increase activity and release more production and completions data.

Based upon our initial 2018 capital expenditure budget, we estimate that our 2018 average daily production will be between 19.8 Mboe/d and 22.0 Mboe/d, with average daily production in the first quarter of 2018 between 19.2 Mboe/d and 21.4 Mboe/d. Because we are drilling both long laterals and utilizing pad drilling (as discussed below in Impact of Pad Drilling), which will result in longer lead-times and require offset shut-ins, production is expected to be less evenly distributed than previous years. The table below sets forth our full year and first quarter 2018 guidance in more detail:

	2018E	**1Q18E**
Total Production (MMBoe)	7.0 - 7.8	1.7 - 1.9
Average Daily Production (MBoe/d)	19.3 - 21.5	19.2 - 21.4
Crude Oil (MBbl/d)	5.6 - 6.2	
Natural Gas (MMcf/d)	46.4 - 51.5	
NGLs (MBbl/d)	6.0 - 6.7	
Lease Operating Expense ($mm)	$43.0 - $46.0	
Production Taxes (% of Unhedged Revenue)(1)	4.0% - 4.5%	
Ad Valorem Taxes ($mm)(1)	$1.0 - $2.0	
Cash G&A Expense ($mm)	$22.0 - $24.0	

(1) Production and ad valorem taxes are included as a single-line item on our Statements of Operations.

These estimates are based on our current planned capital expenditures, drilling activity and expected well results. However, achieving this production estimate and maintaining the required drilling activity to achieve this estimate will depend on the availability of capital, regulatory approvals, commodity prices, drilling and completion costs, actual drilling results and other factors. To the extent any of these factors change adversely, we may not be able to achieve these production results. See Cautionary Statement Regarding Forward-Looking Statements and Risk Factors.

Impact of Pad Drilling.

We intend to drill and complete the majority of the wells in our 2018 development program using pad drilling, which is the practice of drilling wells in batches of two or more from the same drilling pad. While pad drilling generally does produce time and cost efficiencies, such as rig mobility time and costs and the sharing of production facilities, it also increases spud-to-production times which results in production delays. For example, on a four-well pad, all four wells on the pad are drilled before completion operations can begin, at which point all four wells must be completed before any of the wells can be turned to production. This process can result in large amounts of production coming online at one time, and will likely cause our development production profile to be less evenly distributed than previous years. While the potential unevenness of our 2018 development production may make near-term forecasting more difficult, we believe the potential capital savings and operational efficiencies of pad drilling are significant.

Commodity Price Hedging.

The price we receive for our oil, natural gas and NGLs significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Oil and natural gas are commodities and, therefore, their prices can be subject to wide fluctuations in response to relatively minor changes in supply and demand. We believe these prices will likely continue to be volatile in the future. Historically, to mitigate the risk associated with commodity price fluctuations, we have maintained a high level of hedges relative to our projected production. In 2018, our ability to maintain our existing hedges and execute new hedges may be impacted by the reduction and potential amendments to our Revolving Credit Facility. The estimated current mark-to-market value of our commodity price hedges in 2018 and beyond represents a loss of $56.7 million, incorporating strip pricing as of February 1, 2018 but excluding adjustments for credit risk. As of December 31, 2017, 25%, 74% and 78% of our oil, natural gas and NGL production was hedged, respectively.

Western Anadarko Basin Development Plan.

We expect to maintain our leadership and best-in-class operations in the Western Anadarko Basin. In addition to pursuing potential sources of outside development capital to drill in this basin, as discussed below, we are focused on optimizing our existing production from a large and diversified base of 944 gross (571 net) producing wells across approximately 152,000 net acres in the Western Anadarko Basin. Based on our initial capital expenditures budget described above, we expect to drill at least five wells in the Cleveland in 2018.

As previously announced, we are working with Tudor, Pickering, Holt & Co. to evaluate potential drilling joint ventures, or DrillCo, alternatives, which will enable the continued development of our Western Anadarko properties. If we are able to implement a DrillCo to fund a portion of the continued development of our Western Anadarko properties, we anticipate that we will convey a significant majority of the working interests in certain of our undeveloped properties in the Western Anadarko Basin that are subject to the DrillCo to a third party investor in exchange for the third party investor funding capital expenditures to develop such properties. Upon achieving a specified internal rate of return, the third party investor will re-convey those working interests to us, but retain a small portion for themselves. No definitive agreements to implement a DrillCo have been reached as of the date of this Report.

Liability Management

In addition to this offering, we intend to continue to pursue additional liability management opportunities with the goal of decreasing our leverage and increasing our financial flexibility. For example, we may pursue strategies such as repurchases of our Existing Senior Notes, including with a portion of the net proceeds of this offering, or exchanges of our Existing Senior Notes at a price significantly below par for newly-issued second lien secured notes. The indenture governing the notes will permit us to incur an unlimited amount of additional junior lien debt, subject to compliance with a fixed charge coverage ratio. Any repurchases or exchanges of Existing Senior Notes at a discount generally will cause us to recognize result in cancellation of debt income for tax purposes.

Amendment of Revolving Credit Facility

In connection with this offering we intend to amend our Revolving Credit Facility to, among other things, (i) permit the issuance of the notes pursuant to this offering and additional senior secured notes in an aggregate principal amount, together with the notes issued pursuant to this offering, not to exceed $700.0 million, (ii) permit the incurrence of liens securing the notes pursuant to the terms of a collateral trust agreement, (iii) permit the Company s subsidiaries that hold the Merge Assets to be designated as unrestricted subsidiaries, subject to the termination of the commitments under the Revolving Credit Facility (the Merge Designation), (iv) reduce the borrowing base under the Revolving Credit Facility to $50.0 million, effective as of the closing date of this offering, (v) permit additional investments in the Company s subsidiaries that hold the Merge Assets in an aggregate amount not to exceed $75.0 million, (vi) suspend testing of our senior secured leverage ratio until March 31, 2019 and (vii) suspend certain covenants indefinitely, including the financial maintenance covenants under the Revolving Credit Facility, upon consummation of the Merge Designation. We have received commitments from our lenders to amend the Revolving Credit Facility as described above upon consummation of this offering, subject to final documentation.

Preferred Stock Dividend Declared

On January 11, 2018, the Company s Board of Directors declared a quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the 8.0% Series A Perpetual Convertible Preferred Stock (the Series A Preferred Stock), to be paid entirely in shares of Class A common stock (the February Preferred Dividend). The price per share of the Class A common stock used to determine the number of shares issued will equal to 95% of the average volume-weighted average price per share for each day during the five-consecutive day trading period ending immediately prior to the payment date. The February Preferred Dividend will be paid on February 15, 2018 for the period beginning on the last payment date of November 15, 2017 through February 14, 2018 to shareholders of record as of February 1, 2018.

SUMMARY HISTORICAL RESERVE AND OPERATING DATA

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, 2017, 2016 and 2015, which are based upon reserve reports of Cawley, Gillespie & Associates, Inc., our independent reserve engineers. Cawley Gillespie s reports were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserve reporting in effect during such periods. The reserve data set forth below includes the Arkoma Assets, where applicable. Historical reserve volumes and values are not necessarily indicative of results that may be expected for any future period. For additional information relating to our estimated oil and natural gas reserves, please read Business and Risk Factors 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.

	As of December 31,		
	2017	**2016**	**2015**
Reserve Data:			
Estimated proved reserves:			
Oil (MBbls)	29,014	23,594	25,408
Natural gas (MMcf)	255,148	283,140	261,596
NGLs (MBbls)	33,273	34,425	32,649
Total estimated proved reserves (MBoe)(1)	104,812	105,209	101,657
Estimated proved developed reserves:			
Oil (MBbls)	15,416	11,471	11,032
Natural gas (MMcf)	159,459	180,293	169,651
NGLs (MBbls)	20,181	20,941	19,670
Total estimated proved developed reserves (MBoe)(1)	62,173	62,461	58,977
Estimated proved undeveloped reserves:			
Oil (MBbls)	13,598	12,123	14,376
Natural gas (MMcf)	95,689	102,847	91,945
NGLs (MBbls)	13,092	13,484	12,980
Total estimated proved undeveloped reserves (MBoe)(1)	42,639	42,748	42,680
PV-10 (in millions)(2)	$ 627	$ 401	$ 470
Standardized measure (in millions)(3)	567	383	465

(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 the standardized measure of discounted future net cash flows, 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 the standardized measure of discounted future net cash flows 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 ASC Topic 932, Extractive Activities Oil and Gas.

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

	As of December 31,		
	2017	2016	2015
Oil, Natural Gas and NGLs Benchmark Prices:			
Oil (per Bbl)(1)	$ 51.34	$ 42.75	$ 50.25
Natural gas (per MMBtu)(2)	2.96	2.46	2.59
NGLs (per Bbl)(3)	18.92	17.73	17.63

(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, 2017, 2016 and 2015, the average realized prices for oil were $47.45, $38.80 and $45.97 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, 2017, 2016 and 2015, the average realized prices for natural gas were $2.10, $2.19 and $2.37 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 and through our divestiture of the Arkoma Assets, purchasers of our Arkoma Woodford production elected not to recover ethane from the natural gas stream and instead paid 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 increased the incremental revenue and volumes that we received for our natural gas product relative to what we would have received if the ethane was separately recovered, but reduced physical barrels of liquid ethane that we sold.

As set forth above, the amount of our proved reserves, as estimated based on SEC pricing and definitions, was 104.8 MMBoe as of December 31, 2017, of which 59% were classified as proved developed reserves. This decrease of 0.4%, from 105.2 MMBoe as of December 31, 2016, was primarily due to the divestiture of our Arkoma Assets, offset by reserve extensions in the Merge during 2017.

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.

Probable reserves are 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. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us.

Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

Reserves Sensitivities

Using SEC pricing of December 31, 2017, our total estimated proved reserves were 104.8 MMBoe, the standardized measure was $567.2 million and the corresponding SEC PV-10 was $626.6 million. Assuming NYMEX strip pricing as of January 2, 2018 through 2023 and keeping pricing flat thereafter, instead of 2017 SEC pricing, and leaving all other parameters unchanged, our proved reserves would have been 105.7 MMBoe and the corresponding NYMEX PV-10 would have been $721.3 million. This alternative pricing scenario is provided only to demonstrate the impact that the current pricing environment may have on reserve volumes and PV-10 value. There is no assurance that these prices will actually be realized.

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.

(in thousands of dollars except for production, sales price and average cost data)	Three Months Ended September 30, 2017	2016	Change	Nine Months Ended September 30, 2017	2016	Change
Net production volumes:						
Oil (MBbls)	481	396	85	1,391	1,271	120
Natural gas (MMcf)	5,171	4,602	569	15,663	14,130	1,533
NGLs (MBbls)	627	549	78	1,833	1,633	200
Total (MBoe)	1,970	1,712	258	5,835	5,259	576
Average net (Boe/d)	21,413	18,609	2,804	21,374	19,193	2,181
Average sales price, unhedged:						

Oil (per Bbl), unhedged	$ 44.84	$ 39.94	$ 4.90	$ 45.40	$ 35.59	$ 9.81
Natural gas (per Mcf), unhedged	1.82	2.08	(0.26)	2.15	1.50	0.65
NGLs (per Bbl), unhedged	20.17	13.09	7.08	19.46	11.99	7.47
Combined (per Boe), unhedged	22.15	19.03	3.12	22.70	16.36	6.34
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 79.50	$ 87.34	$ (7.84)	$ 81.44	$ 86.26	$ (4.82)
Natural gas (per Mcf), hedged	3.62	3.46	0.16	3.77	3.51	0.26
NGLs (per Bbl), hedged	13.63	17.54	(3.91)	14.30	17.40	(3.10)
Combined (per Boe), hedged	33.26	35.12	(1.86)	34.03	35.69	(1.66)
Average costs (per BOE):						
Lease operating	$ 4.80	$ 4.59	$ 0.21	$ 4.75	$ 4.57	$ 0.18
Production and ad valorem taxes	1.40	1.01	0.39	0.80	0.96	(0.16)
Depletion, depreciation and amortization	23.53	21.35	2.18	21.82	22.14	(0.32)
General and administrative	3.97	3.77	0.20	4.20	4.20	

RISK FACTORS

As used in this section, references to the Issuers, we, our or us refer solely to Jones Energy Holdings, LLC and Jones Energy Finance Corp. and not to their subsidiaries (other than, with respect to Jones Energy Holdings, LLC, Jones Energy Finance Corp.), references to JONE refer to Jones Energy, Inc. and not any of its subsidiaries, and Guarantors refers collectively to JONE, Nosley Assets, LLC, Jones Energy, LLC, Nosley SCOOP, LLC and Nosley Acquisition, LLC.

For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2016 and the information in Item 1A. Risk Factors in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2017. There have been no material changes in our risk factors from those described in our Annual Report for the year ended December 31, 2016, except as set forth below.

Risks Relating to the Oil and Natural Gas Industry and Our Business

Our actual operating results and activities and capital expenditures could differ materially from our guidance.

We have included in this Report certain forecasted operating results, costs and activities, including, without limitation, our future expected production, drilling and completion budget, capital expenditures, drilling activity, hedging strategy and potential joint ventures. Our production estimates are based on reasonable assumptions derived from our current drill schedule, historical and expected well performance, expected drilling, completion and equipping costs, type curves, and cycle times, which are all subject to change. In addition, achieving these production estimates and maintaining the required drilling activity to achieve these estimates will depend on the availability of capital, regulatory approval and the existing regulatory environment, commodity prices and differentials, rig availability, pressure pumping services availability, proppant availability, actual drilling results (including continued well performance success, lack of well loss due to mechanical failure and lack of significant interwell interference in spacing pilots) as well as other factors. To the extent any of these factors changes adversely, we may not be able to achieve these production results. This forward-looking guidance represents our management s estimates as of the date of this Report, is based upon a number of assumptions that are inherently uncertain, including among others the assumptions described above, and is subject to numerous business, economic, competitive, financial and regulatory risks, including the risks described under Risk Factors and Cautionary Statement Regarding Forward-Looking Statements in this Report and JONE s periodic reports incorporated herein by reference. Many of these risks and uncertainties are beyond our control, such as declines in commodity prices and the speculative nature of estimating natural gas, NGL and oil reserves and in projecting future rates of production. If any of these risks and uncertainties actually occur or the assumptions underlying our guidance are incorrect, our actual operating results, costs and activities may be materially and adversely different from our guidance. In addition, investors should also recognize that the reliability of any guidance diminishes the farther in the future that the data is forecast, and it is thus increasingly likely that our actual results will differ materially from our guidance. In light of the foregoing, investors are urged to put our guidance in context and not to place undue reliance upon it.

Our hedging strategy may be ineffective in reducing the impact of commodity price volatility from our cash flows or may limit our ability to realize cash flows from commodity price increases, 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 have historically entered 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. For the years ending December 31, 2018, 2019 and 2020, approximately 22%, 77% and 80%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2017, 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. For example, the estimated mark-to-market value of our commodity price hedges in 2018 and beyond represents a loss of $56.7 million, incorporating strip pricing as of February 1, 2018 but excluding adjustments for credit risk.

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 projected. 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.

Over 72% of our estimated proved reserves are located in the Western Anadarko Basin in the Texas Panhandle and Oklahoma; however, our 2018 drilling plan is primarily focused on the development of our assets in the Merge play located in the Eastern Anadarko Basin in Oklahoma. Drilling and exploring for, and producing, oil, natural gas and NGLs in a different play than the location of our historical operations subjects us to uncertainties that could adversely affect our business, financial condition or results of operations.

Over 72% of our estimated proved reserves as of December 31, 2017 were located in the Western Anadarko Basin in the Texas Panhandle and Oklahoma, and approximately 71% of our 2017 production was from the Cleveland formation where properties are located in four contiguous counties of Texas and Oklahoma. During the fourth quarter of 2017, however, we released our remaining rig in the Cleveland formation. In 2018, we plan to target the liquids rich Woodford shale and Meramec formations in the Merge with a two-rig program. As a result of this change in the area of our significant operations, we may be exposed to the impact of different supply and demand factors, regulations, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations than we have been exposed to previously in our historical operations in the Western Anadarko Basin. These uncertainties and others inherent in allocating our capital resources to operations in a new geographic area could have a material adverse effect on our financial condition and results of operations.

In certain circumstances including transactions involving a change in control, significant 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.

Under certain circumstances, we could become obligated to make significant payments under our Tax Receivable Agreement that could exceed or represent a substantial portion of our liquidity and market capitalization. These payment obligations could be to persons without significant equity ownership in us at the time such obligation arises. 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. Such calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including the assumptions that (i) we have sufficient taxable income to fully utilize such benefits, (ii) any JEH LLC Units that the Class B shareholders or their permitted transferees own on the termination date are exchanged for shares of our Class A common stock on the termination date and (iii) the amount of future depletion deductions to which we are entitled is based on recoverable reserves and rates of recovery reflected in the most recent reserve reports and estimates available 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. For example, if the Tax Receivable Agreement had been terminated at December 31, 2017, we estimate that the termination payment would have been between $53.9 million and $58.4 million (calculated at the 21% U.S. federal corporate income tax rate under the recently enacted Tax Cuts and Jobs Act, and applicable state and local income tax rates and using a discount rate equal to LIBOR, plus 100 basis points, applied against the anticipated undiscounted liability and assuming a market value of our Class A common stock equal to $1.10 per share, the closing price on December 29, 2017). The foregoing is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

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 Class B shareholder will be netted against payments otherwise to be made, if any, to such Class B shareholder 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.

INDEPENDENT RESERVE ENGINEERS

The information included in this Report regarding estimated quantities of proved reserves, the future net revenues from those reserves and their present value is based, in part, on estimates of the proved reserves and present values of proved reserves as of December 31, 2017, 2016 and 2015. The reserve estimates are based on reports prepared by Cawley Gillespie & Associates, Inc., independent reserve engineers, a summary of which is attached to this Report as Exhibit 99.3. These estimates have been incorporated in this Report in reliance upon the authority of each such firm as an expert in these matters.

NON-GAAP FINANCIAL MEASURES

SEC PV-10 and NYMEX PV-10, each as defined below, are considered non-GAAP financial measures. SEC PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. SEC PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. SEC PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date based on SEC pricing, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of SEC 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, NGL 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, NGL and natural gas properties. SEC PV-10, however, is not equal to, or a substitute for, the standardized measure of discounted future net cash flows. Our SEC 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.

NYMEX PV-10 as disclosed in this Report differs from the standardized measure due to the oil and natural gas prices utilized in the determination of future net cash flows and other factors including, but not limited to, regional differentials in price that vary from SEC pricing. We believe that NYMEX PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows based on the current commodity price environment.

The following table provides a reconciliation of the components of the standardized measure of discounted future net cash flows to SEC PV-10 at December 31, 2017, 2016 and 2015 and NYMEX PV-10 at December 31,2017.

	As of December 31,		
(in millions of dollars)	**2017**	**2016**	**2015**
Standardized measure	**$ 567.2**	**$ 383.5**	**$ 464.8**
Present value of future income taxes discounted at 10%	59.4	17.9	5.1
SEC PV-10	**$ 626.6**	**$ 401.4**	**$ 469.9**
Change in pricing assumptions from NYMEX to SEC	$ 94.7		
NYMEX PV-10	$ 721.3		

MARKET AND INDUSTRY DATA

Market and industry data and forecasts used in this Report have been obtained from independent industry sources as well as from research reports prepared for other purposes. Although we believe these third-party sources to be reliable, we have not independently verified the data obtained from these sources and we cannot assure you of the accuracy or completeness of the data. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications and uncertainties as the other forward-looking statements in this Report.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Report, including any information in documents incorporated by reference, contains forward-looking statements. All statements, other than statements of historical fact included or incorporated by reference 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 Report, the words could, should, will, may, believe, anticipate, intend, estimate, expect, project 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 many factors that may cause results to differ including those described under Risk Factors in this Report and in JONE s most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q and other filings JONE makes with the Securities and Exchange Commission (the SEC) incorporated by reference herein and elsewhere in this Report. These forward-looking statements are based on JONE 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, and the likelihood of establishing production from such estimates;
- our ability to convert our probable and possible reserves into proved reserves;
- drilling and completion of wells including our identified drilling locations;
- cash flows, liquidity and our leverage;
- financial strategy, capital and operating budgets, projections and operating results;
- future prices and change in prices for oil, natural gas and natural gas liquids (NGL);

- 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 capital expenditure budgets;
- 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 and realizing the expected benefits or effects of completed acquisitions and dispositions, including our ability to consummate a DrillCo in the Western Anadarko Basin;
- 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;
- changes and uncertainties regarding 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 and in the documents incorporated herein by reference.

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 or in the documents incorporated by reference 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 or in the documents incorporated by reference 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.

Item 9.01 **Financial Statements and Exhibits.**

(d) Exhibits

Exhibit No.	**Description**
23.1	Consent of Cawley, Gillespie & Associates, Inc.
99.1	Press Release Regarding Operations Update, dated February 5, 2018
99.2	Press Release Regarding Launch of Offering, dated February 5, 2018
99.3	Summary Report of Cawley, Gillespie & Associates, Inc. for reserves as of December 31, 2017

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 hereunto duly authorized.

	JONES ENERGY, INC.	
Date: February 5, 2018	By:	/s/ Robert J. Brooks Robert J. Brooks Executive Vice President and Chief Financial Officer