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FOR IMMEDIATE RELEASE

PENN VIRGINIA CORPORATION ANNOUNCES THIRD QUARTER 2015 RESULTS

ACTIVELY REVIEWING FINANCING AND DEBT RESTRUCTURING ALTERNATIVES

AVERAGE IP AND 30 DAY RATES UP 88% AND 59% OVER SECOND QUARTER

AVERAGE WELL COST DOWN 30% FROM SECOND QUARTER

NEW BORROWING BASE OF \$275 MILLION, IN LINE WITH EXPECTATIONS

RADNOR, PA (Globe Newswire) November 9, 2015 – Penn Virginia Corporation (NYSE: PVA) today reported financial results for the three months ended September 30, 2015 and provided updates of its operations and guidance.

Key Highlights

Third quarter 2015 results compared, as applicable, to second quarter 2015 results were as follows:

- Total production was 20,976 barrels of oil equivalent (BOE) per day (BOEPD), compared to 23,519 BOEPD.
 - Total production was above the midpoint of production guidance of 18,500 to 22,800 BOEPD.
- The average initial potential (IP) and 30-day rates for 11 Eagle Ford wells turned in line were 1,501 and 790 BOEPD, up 88% and 59% compared to 798 and 497 BOEPD for 16 wells turned in line in the second quarter.
- Gross drilling and completion costs for the 11 wells, including facilities, averaged \$5.7 million per well, approximately 30% lower than the average cost of the 16 second quarter wells.
 - The decrease in average well cost was driven by a transition to drilling exclusively two-string wells, whereas only three of the second quarter wells were two-string wells. In addition, seven of the third quarter wells were slickwater stimulated and all of the third quarter wells were fractured with approximately 46% more proppant per stage, on average, than second quarter wells.
- Product revenues, including derivatives, were \$93.0 million, compared to \$118.0 million.
 - Realized oil, gas and natural gas liquids (NGLs) prices were \$69.19 per barrel, \$2.68 per thousand cubic feet (Mcf) and \$9.81 per barrel, compared to \$82.44 per barrel, \$2.54 per Mcf and \$13.53 per barrel, including hedges.
 - Product revenues per BOE were \$48.17, compared to \$55.12, including hedges.
- Production costs, including lease operating expense, gathering, processing and transportation expenses and production and ad valorem taxes, decreased 8% to \$20.4 million from \$22.3 million.
- Recurring general and administrative (G&A) costs decreased 12% to \$8.2 million from \$9.4 million.
- Adjusted EBITDAX, a non-GAAP (generally accepted accounting principles) measure, was \$65.0 million, compared to \$85.5 million.

Other updates included:

- The borrowing base under the revolving credit facility (Revolver) was recently redetermined to \$275 million.
 - The lower borrowing base was in line with our expectations.
 - At September 30, 2015, our pro forma financial liquidity was \$136 million and our leverage ratio was 3.9 times.
 - Year-end 2015 liquidity is expected to be \$103 to \$118 million.
- Preliminarily, we estimate 2016 capital expenditures to be between \$140 and \$160 million, down from earlier preliminary guidance of \$200 to \$250 million.
 - Fourth quarter 2016 oil production is now expected to be approximately 5% less than fourth quarter 2015.

Definitions of non-GAAP financial measures and reconciliations of these non-GAAP financial measures to GAAP-based measures appear later in this release.

Management Comment

Edward B. Cloues, II, Chairman and interim Chief Executive Officer stated, "Our third quarter results were largely as expected, despite lower than anticipated oil prices, as our operating costs continued to decrease. Our third quarter production came in slightly above the midpoint of third quarter guidance, due primarily to the higher productivity of our most recent wells. In particular, we were encouraged with the early results of our most recent seven two-string, slickwater fracked wells in the Lower Eagle Ford, both in terms of their average cost and initial productivity. The last five of these wells, also utilizing zipper fracs, were on average the best wells we have drilled out of nearly 330 producing wells we and our partners have drilled over the past five years. The higher initial production of our wells turned in line in the third quarter, and the lower costs of those wells, which were 30% lower than the average cost of wells we turned in line in the second quarter, should generate higher than historical internal rates of return even in the current price environment.

"We will continue to focus our drilling efforts on two-string, Lower Eagle Ford wells in Gonzales County and northwestern Lavaca County, where we believe our rates of return are optimized. The redirection of our drilling program to this lower-cost area, where we have experienced higher productivity with the slickwater fracs, has led us to reduce preliminary capital expenditures guidance for 2016 for a 1-rig drilling program, as detailed later in this release."

Mr. Cloues concluded, "With respect to financial liquidity, our borrowing base redetermination, while lower, was in line with our expectations given the current commodity price environment. To further supplement liquidity, during the third quarter and in early October we sold our East Texas and certain non-core Eagle Ford assets for gross proceeds of \$88 million. However, we anticipate that we will exceed the total debt leverage covenant in the Revolver at the end of the first quarter of 2016, which would require us to seek a waiver from our bank lenders, which may or may not be forthcoming. Consequently, we are actively reviewing various financing and debt restructuring alternatives in an attempt to shore up our overall liquidity and relieve our dependence upon the Revolver as our sole source of external funding."

Third Quarter 2015 Results

Overview of Results

Operating income was \$3.6 million in the third quarter of 2015, compared to an operating loss of \$41.0 million in the second quarter of 2015. This \$44.6 million improvement was due primarily to \$50.8 million of gains related to asset sales and a \$16.2 million decrease in operating expenses, partially offset by a \$22.4 million decrease in product revenues.

Net income attributable to common shareholders for the third quarter was \$20.0 million, or \$0.25 per diluted share, compared to net loss of \$86.2 million, or \$1.19 per diluted share, in the prior quarter. The primary reasons for the \$106.2 million improvement were the \$44.6 million increase in operating income and a \$60.2 million increase in derivatives income, which includes mark-to-market adjustments. Adjusted net loss attributable to common shareholders, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of non-cash derivatives expense and other items that affect comparability to other periods, was \$43.3 million, or \$0.60 per diluted share, for the third quarter compared to a loss of \$31.6 million, or \$0.44 per diluted share, in the prior quarter. The primary reasons for the \$11.6 million increase in the loss were the \$22.4 million decrease in product revenues and a \$2.6 million decrease in cash settlements of derivatives, partially offset by the \$16.2 million decrease in operating expenses.

Production

As shown in the table below, total production in the third quarter of 2015 was 20,976 BOEPD, compared to 23,519 BOEPD in the second quarter of 2015, with a 1,731 BOEPD decrease in the Eagle Ford and an 812 BOEPD decrease in other areas, primarily related to the sale of East Texas assets in August 2015. Pro forma for the sale of East Texas, production declined by 1,764 BOEPD to 19,857 BOEPD in the third quarter of 2015 from 21,621 BOEPD in the prior quarter.

Region / Play Type	Total and Daily Equivalent Production for the Three Months Ended					
	Sept. 30, 2015	June 30, 2015	Sept. 30, 2014	Sept. 30, 2015	June 30, 2015	Sept. 30, 2014
	(in MBOE)			(in BOEPD)		
Eagle Ford Shale	1,705	1,844	1,557	18,528	20,259	16,929
Mid-Continent	117	119	258	1,271	1,302	2,802
Other	108	177	274	1,177	1,958	2,975
Totals	1,930	2,140	2,089	20,976	23,519	22,706
Pro Forma Totals⁽¹⁾	1,827	1,967	1,712	19,857	21,621	18,617

Note - Numbers may not add due to rounding. MBOE equals one thousand barrels of oil equivalent.

⁽¹⁾ Pro forma to exclude volumes from divested Mississippi and East Texas properties, as well as the third quarter 2014 Mid-Continent adjustment.

Product Revenues

Total product revenues decreased by \$22.4 million, or 27%, to \$60.7 million, or \$31.45 per BOE, in the third quarter of 2015, from \$83.1 million, or \$38.84 per BOE, in the second quarter of 2015, due primarily to a 19% decrease in the realized oil equivalent price and an 11% decrease in production. For the third quarter, the realized oil price decreased by 23%, the realized natural gas price increased by 5% and the realized NGL price decreased by 27% compared to the second quarter of 2015. Including derivatives, total product revenues were \$93.0 million, or \$48.17 per BOE, in the third quarter of 2015, compared to \$118.0 million, or \$55.12 per BOE, in the second quarter of 2015.

Operating Expenses

As discussed below, third quarter 2015 total direct operating expenses, excluding share-based compensation and non-recurring expenses, decreased by \$3.0 million to \$28.7 million, or \$14.87 per BOE produced, from \$31.7 million, or \$14.80 per BOE produced, in the second quarter of 2015.

- Lease operating expense increased by \$0.4 million to \$11.3 million, or \$5.86 per BOE, from \$10.9 million, or \$5.10 per BOE, due to increased compression and saltwater disposal expenses, partially offset by decreased workover and chemicals and fluids expenses.
- Gathering, processing and transportation expense decreased by \$0.7 million to \$5.7 million, or \$2.93 per BOE, from \$6.4 million, or \$2.98 per BOE, due to decreased production volumes.
- Production and ad valorem taxes decreased by \$1.5 million to \$3.5 million, or 5.7% of product revenues, from \$5.0 million, or 6.0% of product revenues, due to lower commodity prices.
- Recurring G&A expense decreased by \$1.2 million to \$8.2 million, or \$4.27 per BOE, from \$9.4 million, or \$4.40 per BOE. The decrease in recurring G&A expense was due primarily to lower consulting and professional fees and salary and wages expense.

Depletion, depreciation and amortization expense in the third quarter of 2015 decreased by \$8.5 million to \$76.9 million, or \$39.82 per BOE, from \$85.4 million, or \$39.91 per BOE, in the second quarter.

Capital Expenditures

During the third quarter of 2015, capital expenditures were \$40 million, a decrease of \$54 million, or 58%, compared to \$94 million in the second quarter of 2015, consisting of:

- A decrease of approximately \$48 million for drilling and completion activities, to approximately \$40 million.
- A net decrease of approximately \$6 million to approximately zero for pipeline, gathering, facilities, seismic, leasehold acquisition and other capital expenditures.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of September 30, 2015, we had total debt of \$1,215 million, consisting of \$300 million principal amount of 7.25% senior unsecured notes due 2019, \$775 million principal amount of 8.50% senior unsecured notes due 2020 and \$140 million drawn under the Revolver, down \$72 million from June 30, 2015. In November 2015, the borrowing base under the Revolver was reduced from \$395 million to \$275 million, which was in line with our expectations. Together with cash and equivalents of \$3 million and net of letters of credit of \$2 million, our financial liquidity was \$256 million at September 30, 2015. Pro forma liquidity, after giving effect to the new borrowing base of \$275 million, was \$136 million.

Our total debt leverage ratio under the Revolver at September 30, 2015 was 3.9 times trailing twelve months' Adjusted EBITDAX of \$313 million. The maximum leverage ratio allowable during the third quarter of 2015 under the Revolver was 4.75 times. An additional covenant for credit exposure, defined as all outstanding borrowings under the Revolver plus any outstanding letters of credit, has a maximum allowable ratio of 2.75 times through March 31, 2017. At September 30, 2015, this ratio was 0.5 times.

During the third quarter, interest expense was \$23.0 million, of which \$21.8 million was cash interest expense, unchanged from the second quarter.

During the third quarter, derivatives income was \$44.7 million, compared to derivatives expense of \$15.5 million in the second quarter. Third quarter cash settlements of derivatives resulted in net cash receipts of \$32.3 million, compared to \$34.8 million of net cash receipts in the second quarter.

Derivatives Update

To support our operating cash flows, we hedge a portion of our oil and natural gas production at predetermined prices or price ranges. Currently, we have hedged 11,000 barrels of daily crude oil production during the fourth quarter of 2015, or about 90% to 100% of our expected oil production, at a weighted average floor/swap price of \$89.86 per barrel. We have sold put options for 5,000 barrels of daily crude oil production during the fourth quarter of 2015, with all put options sold at a strike price of \$70.00 per barrel. For 2016, we have hedged 6,000 barrels of daily crude oil production at a weighted average floor/swap price of \$80.41 per barrel. We currently do not have any natural gas derivatives.

Please see the Derivatives Table included in this release for our current derivative positions.

Full-Year 2015 Guidance Update and Preliminary 2016 Guidance

Full-year 2015 guidance highlights are as follows:

- Production of approximately 21,300 to 21,800 BOEPD, compared to previous guidance of approximately 20,700 to 22,600 BOEPD.
 - 2015 crude oil production of approximately 13,200 to 13,500 barrels of oil per day (BOPD), compared to previous guidance of 13,050 to 14,350 BOPD.
 - Production in the fourth quarter of 2015 is expected to range between approximately 16,200 and 18,100 BOEPD, compared to previous guidance of between 16,300 and 19,600 BOEPD.
- Product revenues, excluding the impact of any derivatives, are expected to be \$264 to \$269 million, compared to previous guidance of \$284 to \$307 million.
 - Our crude oil revenue estimate assumes realized pricing of West Texas Intermediate (WTI) crude oil benchmark pricing of approximately \$45 per barrel, compared to previous guidance of \$55 per barrel. Benchmark (Henry Hub) natural gas pricing is assumed to be \$2.56 per Mcf, compared to previous guidance of \$2.88 per Mcf, while NGL pricing is assumed to be 19% of the WTI price.
 - Cash receipts from the settlement of derivatives are expected to be \$134 million, based on the foregoing assumptions, compared to previous guidance of \$127 million.
- Adjusted EBITDAX, a non-GAAP measure, is expected to be \$280 to \$284 million, compared to previous guidance of \$285 to \$310 million.
- Capital expenditures are expected to be \$316 to \$324 million, compared to previous guidance of \$325 to \$345 million.
 - Drilling and completion capital expenditures are expected to be \$296 to \$302 million, compared to previous guidance of \$305 to \$320 million.
 - Pipeline, gathering, facilities, seismic and other capital expenditures are expected to be \$6 to \$7 million, compared to previous guidance of \$5 to \$8 million.
 - Lease acquisition capital expenditures are expected to be \$14 to \$15 million, essentially unchanged compared to previous guidance.

Please see the Guidance Table included in this release for guidance estimates for fourth quarter and full-year 2015.

Preliminarily, and based on crude oil prices, specifically \$48 to \$52 per barrel WTI, we expect to spend \$140 to \$160 million in capital expenditures during 2016, with fourth quarter 2016 oil production approximately 5% lower than the midpoint of fourth quarter 2015 oil production guidance (overall production approximately 10% lower). This compares to previous preliminary guidance, which assumed a \$55 to \$60 per barrel WTI crude oil pricing, of \$200 to \$250 million in capital expenditures during 2016. The 2016 preliminary capital budget will be funded by anticipated year-end 2015 liquidity and 2016 cash flows from operating activities.

2015 estimates and 2016 preliminary estimates are meant to provide guidance only and are subject to revision as the operating environment changes.

Eagle Ford Shale Operational Update

Third Quarter 2015 Update

Third quarter production from our Eagle Ford operations was 18,528 BOEPD, a 9% decrease from the 20,259 BOEPD produced in the second quarter of 2015. Approximately 69% of our third quarter Eagle Ford production was from crude oil, 18% was from NGLs and 13% was from natural gas. The decrease was attributable primarily to our reduction in drilling activity as the year progressed, in light of lower oil and gas prices.

Well Cost Reductions and Improved Well Results

The average gross well cost for 11 (two-string) wells turned in line during the third quarter of 2015 was approximately \$5.7 million, down 30% from an average of \$8.2 million for 16 (two-string and three-string wells) wells turned in line in the second quarter of 2015. The decrease in average well cost was driven by a transition to drilling exclusively two-string wells, whereas only three of the second quarter wells were two-string wells. In addition, seven of the third quarter wells were slickwater stimulated and all of the third quarter wells were fractured with approximately 46% more proppant per stage, on average, than second quarter wells.

Recent Eagle Ford Well Results

Below are the results and statistics for Eagle Ford wells over the past five quarters: ⁽²⁾

Time Period	Averages									
	Gross / Net Wells	Lateral Length <i>Feet</i>	Frac Stages	Proppant <i>lbs.</i>	Peak Gross Daily Production Rates ⁽³⁾			30-Day Average Gross Daily Production Rates ⁽³⁾		
					Oil	Equivalent	Oil	Oil	Equivalent	Oil
					Rate	Rate	Percentage	Rate	Rate	Percentage
				<i>BOPD</i>	<i>BOEPD</i>		<i>BOPD</i>	<i>BOEPD</i>		
2014 - 3 rd quarter	22 / 12.2	5,813	27.4	10,129,710	1,050	1,244	85%	659	777	85%
2014 - 4 th quarter	23 / 17.1	5,486	25.7	9,849,071	880	1,256	70%	634	900	72%
2015 - 1 st quarter	25 / 13.7	6,345	27.2	8,089,820	1,048	1,254	84%	681	805	85%
2015 - 2 nd quarter	16 / 11.4	6,008	24.4	7,014,972	604	798	76%	388	497	77%
2015 - 3 rd quarter	11 / 8.5	5,040	21.2	9,082,417	1,381	1,501	93%	726	790	92%
Totals and averages	97 / 62.9	5,817	25.7	8,904,885	973	1,205	81%	622	769	82%
Operating Area										
Peach Creek	14 / 8.6	5,128	23.6	9,677,214	1,364	1,488	92%	756	819	93%
Rock Creek / Bozka	8 / 3.7	5,461	25.9	9,517,026	1,313	1,486	88%	910	1,032	88%
Upper Eagle Ford	30 / 24.3	6,002	26.0	8,724,670	614	960	68%	465	710	70%
Lavaca "Beer Area"	20 / 9.4	6,032	27.2	9,505,123	1,128	1,387	81%	715	862	82%
Shiner	9 / 6.8	5,932	24.8	7,179,445	899	1,205	73%	546	715	75%
Shallow Gonzales	16 / 10.0	5,917	25.6	8,481,194	983	1,049	94%	579	615	94%
Totals and averages	97 / 62.9	5,817	25.7	8,904,885	973	1,205	81%	622	769	82%

⁽²⁾ Excludes two Upper Eagle Ford wells and one Lower Eagle Ford well which had mechanical issues.

⁽³⁾ Wellhead rates only; the natural gas associated with these wells is yielding between 135 and 155 barrels of NGLs per million cubic feet.

Since the end of the second quarter of 2015, we have turned in line 11 (8.5 net) operated wells. As a group, these 11 wells had an average IP rate of 1,501 BOEPD over an average of 21.2 frac stages, with 93% of production from crude oil, compared to 798 BOEPD over an average of 24.4 stages for 16 second quarter wells. All of the third quarter wells were drilled in the Lower Eagle Ford and had a 30-day average rate of 790 BOEPD, with 92% of production from crude oil, compared to an average of 497 BOEPD for the second quarter wells. The average amount of proppant per stage for these 11 wells was approximately 422,000 pounds and the average amount of proppant per lateral foot was approximately 1,800 pounds, compared to approximately 290,000 pounds per stage and 1,170 pounds per lateral foot in the second quarter of 2015. We believe the strong improvement in early-time production rates is attributable to the use of slickwater stimulations, continued use of "zipper" fracs for alternating laterals on multi-well pads and increased frac intensity as measured by the increased proppant pumped per stage.

Drilling Program Outlook

For the remainder of 2015 and for 2016, due primarily to anticipated low oil prices, we will continue to focus our efforts on drilling, using one rig, less costly two-string Lower Eagle Ford wells in Gonzales County and northwestern Lavaca County where our economics are optimized.

Third Quarter 2015 Conference Call

A conference call and webcast, during which management will discuss third quarter 2015 financial and operational results, is scheduled for Tuesday, November 10, 2015 at 10:00 a.m. ET. Prepared remarks will be followed by a question and answer period. Investors and analysts may participate via phone by dialing toll free 1-877-316-5288 (international: 1-734-385-4977) five to 10 minutes before the scheduled start of the conference call (use the conference code 59451145), or via webcast with presentation slides by logging on to our website, www.pennvirginia.com, at least 15 minutes prior to the scheduled start of the call to download and install any necessary audio software. A telephonic replay will be available for two weeks beginning approximately 24 hours after the call. The replay can be accessed by dialing toll free 1-855-859-2056 (international: 1-404-537-3406) and using the replay code 59451145. In addition, an on-demand replay of the webcast will also be available for two weeks at our website beginning approximately 24 hours after the webcast.

Penn Virginia Corporation (NYSE: PVA) is an independent oil and gas company engaged in the exploration, development and production of oil, NGLs and natural gas in various domestic onshore regions of the United States, with a primary focus in the Eagle Ford Shale in south Texas. For more information, please visit our website at www.pennvirginia.com.

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following: the volatility of commodity prices for oil, natural gas liquids, or NGLs and natural gas; our ability to develop, explore for, acquire and replace oil and natural gas reserves and sustain production; our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations; our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms; compliance with debt covenants; reductions in the borrowing base under the Revolver; our ability to continue to borrow under the Revolver; any impairments, write-downs or write-offs of our reserves or assets; the projected demand for and supply of oil, NGLs and natural gas; our ability to contract for drilling rigs, supplies and services at reasonable costs; our ability to obtain adequate pipeline transportation capacity for our oil and gas production at reasonable cost and to sell the production at, or at reasonable discounts to, market prices; the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from estimated proved oil and natural gas reserves; drilling and operating risks; our ability to compete effectively against other oil and gas companies; our ability to successfully monetize select assets and repay our debt; leasehold terms expiring before production can be established; environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance; the timing of receipt of necessary regulatory permits; the effect of commodity and financial derivative arrangements; the occurrence of unusual weather or operating conditions, including force majeure events; our ability to retain or attract senior management and key technical employees; counterparty risk related to the ability of these parties to meet their future obligations; compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters; physical, electronic and cybersecurity breaches; uncertainties relating to general domestic and international economic and political conditions; and other risks set forth in our filings with the Securities and Exchange Commission (SEC).

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management’s views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to PVA or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited
(in thousands, except per share data)

	Three months ended September 30,		Three months ended June 30,		Nine months ended September 30,	
	2015	2014	2015	2015	2015	2014
Revenues						
Crude oil	\$ 51,124	\$ 118,716	\$ 70,672	\$ 180,964	\$ 336,382	
Natural gas liquids (NGLs)	3,254	9,790	5,191	13,841	27,200	
Natural gas	6,312	13,354	7,260	22,143	47,859	
Total product revenues	60,690	141,860	83,123	216,948	411,441	
Gain (loss) on sales of property and equipment, net	50,828	63,520	66	50,803	120,295	
Other	466	16	427	2,376	2,886	
Total revenues	111,984	205,396	83,616	270,127	534,622	
Operating expenses						
Lease operating	11,304	14,761	10,907	33,780	36,878	
Gathering, processing and transportation (a)	5,654	5,428	6,383	19,535	12,605	
Production and ad valorem taxes	3,483	7,690	4,967	13,139	22,505	
General and administrative (excluding equity-classified share-based compensation) (b)	8,153	10,540	10,363	29,496	40,417	
Total direct operating expenses	28,594	38,419	32,620	95,950	112,405	
Share-based compensation - equity classified awards (c)	1,263	987	1,116	3,369	2,638	
Exploration	1,673	1,986	4,362	11,922	13,995	
Depreciation, depletion and amortization	76,850	71,999	85,416	253,056	215,623	
Impairments	-	6,084	1,084	1,084	123,992	
Total operating expenses	108,380	119,475	124,598	365,381	468,653	
Operating income (loss)	3,604	85,921	(40,982)	(95,254)	65,969	
Other income (expense)						
Interest expense	(22,985)	(21,953)	(23,023)	(68,021)	(67,716)	
Derivatives	44,701	66,457	(15,495)	52,073	8,130	
Other	(44)	1,349	(540)	(586)	1,380	
Income (loss) before income taxes	25,276	131,774	(80,040)	(111,788)	7,763	
Income tax (expense) benefit	624	(42,113)	(89)	394	339	
Net income (loss)	25,900	89,661	(80,129)	(111,394)	8,102	
Preferred stock dividends (d)	(5,935)	(7,641)	(6,067)	(18,069)	(11,081)	
Induced conversion of preferred stock	-	(888)	-	-	(4,256)	
Net income (loss) attributable to common shareholders	<u>\$ 19,965</u>	<u>\$ 81,132</u>	<u>\$ (86,196)</u>	<u>\$ (129,463)</u>	<u>\$ (7,235)</u>	
Net income (loss) per share:						
Basic	\$ 0.27	\$ 1.13	\$ (1.19)	\$ (1.79)	\$ (0.11)	
Diluted	\$ 0.25	\$ 0.87	\$ (1.19)	\$ (1.79)	\$ (0.11)	
Weighted average shares outstanding, basic	72,651	71,536	72,398	72,438	67,909	
Weighted average shares outstanding, diluted	103,452	103,606	72,398	72,438	67,909	

	Three months ended September 30,		Three months ended June 30,		Nine months ended September 30,	
	2015	2014	2015	2015	2015	2014
Production						
Crude oil (MBbls)	1,205	1,247	1,280	3,822	3,442	
NGLs (MBbls)	332	308	384	1,112	796	
Natural gas (MMcf)	2,358	3,201	2,860	8,165	10,412	
Total crude oil, NGL and natural gas production (MBOE)	1,930	2,089	2,140	6,295	5,973	
Prices						
Crude oil (\$ per Bbl)	\$ 42.42	\$ 95.19	\$ 55.22	\$ 47.35	\$ 97.72	
NGLs (\$ per Bbl)	\$ 9.81	\$ 31.76	\$ 13.53	\$ 12.45	\$ 34.18	
Natural gas (\$ per Mcf)	\$ 2.68	\$ 4.17	\$ 2.54	\$ 2.71	\$ 4.60	
Prices - Adjusted for derivative settlements						
Crude oil (\$ per Bbl)	\$ 69.19	\$ 89.08	\$ 82.44	\$ 74.54	\$ 93.08	
NGLs (\$ per Bbl)	\$ 9.81	\$ 31.76	\$ 13.53	\$ 12.45	\$ 34.18	
Natural gas (\$ per Mcf)	\$ 2.68	\$ 4.19	\$ 2.54	\$ 2.80	\$ 4.42	

(a) We have reclassified approximately \$0.5 million and \$1.2 million of certain natural gas compression costs from lease operating expense to gathering, processing and transportation expenses for the three and nine months ended September 30, 2014.

(b) Includes liability-classified share-based compensation expense (credit) of \$(0.9) million and \$(0.4) million for the three months ended September 30, 2015 and 2014 and \$(0.7) million and \$6.6 million for the nine months ended September 30, 2015 and 2014, respectively, attributable to our performance-based restricted stock units. The three months ended June 30, 2015 includes \$(0.2) million attributable to these awards. The awards are payable in cash upon the achievement of certain market-based performance metrics. Also includes professional fees and other costs of approximately \$0.7 million and \$1.2 million for the three and nine months ended September 30, 2015 associated with our ongoing efforts to pursue strategic and/or refinancing transactions. We incurred approximately \$0.4 million of these costs during the three months ended June 30, 2015.

(c) Our equity-classified share-based compensation expense includes non-cash charges for our stock option expense and the amortization of common, deferred and restricted stock and restricted stock unit awards related to equity-classified employee and director compensation in accordance with accounting guidance for share-based payments.

(d) We suspended our preferred stock dividends for the three months ended September 30, 2015; however, the dividends accumulate and are presented in the determination of net income (loss) attributable to common shareholders and earnings (loss) per share.

PENN VIRGINIA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS - unaudited
(in thousands)

	As of	
	September 30, 2015	December 31, 2014
Assets		
Current assets	\$ 179,875	\$ 335,027
Net property and equipment	1,818,586	1,825,098
Other assets	21,985	41,738
Total assets	<u>\$ 2,020,446</u>	<u>\$ 2,201,863</u>
Liabilities and shareholders' equity		
Current liabilities	\$ 161,908	\$ 312,227
Revolving credit facility	140,000	35,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Debt issuance costs	(21,638)	(24,571)
Other liabilities and deferred income taxes	110,105	128,390
Total shareholders' equity	555,071	675,817
Total liabilities and shareholders' equity	<u>\$ 2,020,446</u>	<u>\$ 2,201,863</u>

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited
(in thousands)

	Three months ended September 30,		Three months ended June 30,		Nine months ended September 30,	
	2015	2014	2015	2014	2015	2014
Cash flows from operating activities						
Net income (loss)	\$ 25,900	\$ 89,661	\$ (80,129)		(111,394)	\$ 8,102
Adjustments to reconcile net income (loss) to net cash provided by operating activities:						
Depreciation, depletion and amortization	76,850	71,999	85,416		253,056	215,623
Impairments	-	6,084	1,084		1,084	123,992
Accretion of firm transportation obligation	260	407	233		705	991
Derivative contracts:						
Net losses (gains)	(44,701)	(66,457)	15,495		(52,073)	(8,130)
Cash settlements, net	32,258	(7,557)	34,840		104,590	(17,836)
Deferred income tax expense (benefit)	36	42,113	89		266	(339)
(Gain) loss on sales of assets, net	(50,828)	(63,520)	(66)		(50,803)	(120,295)
Non-cash exploration expense	898	1,808	2,022		4,903	8,387
Non-cash interest expense	1,224	1,063	1,176		3,504	3,114
Share-based compensation (equity-classified)	1,263	987	1,116		3,369	2,638
Other, net	(20)	44	(6)		(17)	325
Changes in operating assets and liabilities	20,820	24,625	(8,541)		5,051	(16,122)
Net cash provided by operating activities	<u>63,960</u>	<u>101,257</u>	<u>52,729</u>		<u>162,241</u>	<u>200,450</u>
Cash flows from investing activities						
Receipts (payments) to settle obligations assumed in acquisition, net	-	33,712	-		-	33,712
Capital expenditures - property and equipment	(60,883)	(194,451)	(94,999)		(324,876)	(545,031)
Proceeds from sales of assets, net	73,891	215,281	(337)		73,670	311,913
Net cash provided by (used in) investing activities	<u>13,008</u>	<u>54,542</u>	<u>(95,336)</u>		<u>(251,206)</u>	<u>(199,406)</u>
Cash flows from financing activities						
Proceeds from the issuance of preferred stock, net	-	(316)	-		-	313,330
Payments made to induce conversion of preferred stock	-	(888)	-		-	(4,256)
Proceeds from revolving credit facility borrowings	6,000	75,000	70,000		203,000	377,000
Repayment of revolving credit facility borrowings	(78,000)	(130,000)	(20,000)		(98,000)	(583,000)
Debt issuance costs paid	-	-	(744)		(744)	(151)
Dividends paid on preferred and common stock	(6,067)	(1,329)	(6,067)		(18,201)	(5,165)
Other, net	-	329	-		-	1,414
Net cash (used in) provided by financing activities	<u>(78,067)</u>	<u>(57,204)</u>	<u>43,189</u>		<u>86,055</u>	<u>99,172</u>
Net increase (decrease) in cash and cash equivalents	(1,099)	98,595	582		(2,910)	100,216
Cash and cash equivalents - beginning of period	4,441	25,095	3,859		6,252	23,474
Cash and cash equivalents - end of period	<u>\$ 3,342</u>	<u>\$ 123,690</u>	<u>\$ 4,441</u>		<u>\$ 3,342</u>	<u>\$ 123,690</u>

PENN VIRGINIA CORPORATION
CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited
(in thousands)

	Three months ended September 30,		Three months ended June 30,		Nine months ended September 30,	
	2015	2014	2015	2014	2015	2014
<u>Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Net income (loss) applicable to common shareholders, as adjusted"</u>						
Net income (loss)	\$ 25,900	\$ 89,661	\$ (80,129)	\$ (111,394)	\$ 8,102	
Adjustments for derivatives:						
Net losses (gains)	(44,701)	(66,457)	15,495	(52,073)	(8,130)	
Cash settlements, net	32,258	(7,557)	34,840	104,590	(17,836)	
Adjustment for impairments	-	6,084	1,084	1,084	123,992	
Adjustment for restructuring costs	23	18	753	765	27	
Adjustment for refinancing and strategic transaction costs	733	-	416	1,195	-	
Adjustment for rig termination charge	517	-	2,039	6,182	-	
Adjustment for (gain) loss on sale of assets, net	(50,828)	(63,520)	(66)	(50,803)	(120,295)	
Impact of adjustments on income taxes	(1,531)	42,004	61	(39)	(971)	
Preferred stock dividends	(5,935)	(7,641)	(6,067)	(18,069)	(11,081)	
Net loss applicable to common shareholders, as adjusted (a)	<u>\$ (43,564)</u>	<u>\$ (7,408)</u>	<u>\$ (31,574)</u>	<u>\$ (118,562)</u>	<u>\$ (26,192)</u>	
<u>Net loss applicable to common shareholders, as adjusted, per share, diluted</u>						
	<u>\$ (0.60)</u>	<u>\$ (0.10)</u>	<u>\$ (0.44)</u>	<u>\$ (1.64)</u>	<u>\$ (0.39)</u>	
<u>Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"</u>						
Net income (loss)	\$ 25,900	\$ 89,661	\$ (80,129)	\$ (111,394)	\$ 8,102	
Income tax benefit	(624)	42,113	89	(394)	(339)	
Interest expense	22,985	21,953	23,023	68,021	67,716	
Depreciation, depletion and amortization	76,850	71,999	85,416	253,056	215,623	
Exploration	1,673	1,986	4,362	11,922	13,995	
Share-based compensation expense (equity-classified awards)	1,263	987	1,116	3,369	2,638	
EBITDAX	<u>128,047</u>	<u>228,699</u>	<u>33,877</u>	<u>224,580</u>	<u>307,735</u>	
Adjustments for derivatives:						
Net losses (gains)	(44,701)	(66,457)	15,495	(52,073)	(8,130)	
Cash settlements, net	32,258	(7,557)	34,840	104,590	(17,836)	
Adjustment for impairments	-	6,084	1,084	1,084	123,992	
Adjustment for (gain) loss on sale of assets, net	(50,828)	(63,520)	(66)	(50,803)	(120,295)	
Adjustment for other non-cash items	260	407	233	705	991	
Adjusted EBITDAX (b)	<u>\$ 65,036</u>	<u>\$ 97,656</u>	<u>\$ 85,463</u>	<u>\$ 228,083</u>	<u>\$ 286,457</u>	

PENN VIRGINIA CORPORATION
GUIDANCE TABLE - unaudited
(dollars in millions except where noted)

We are providing the following guidance regarding financial and operational expectations for 2015. These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

	Actual Results					2015 Guidance			
	Fourth	First	Second	Third	Year-to-	Fourth Quarter		Full-Year	
	Quarter	Quarter	Quarter	Quarter	Date				
	2014	2015	2015	2015	2015				
Production:									
Crude oil (MBbls)	1,202	1,337	1,280	1,205	3,822	1,000 -	1,100	4,822 -	4,922
NGLs (MBbls)	314	397	384	332	1,112	240 -	280	1,352 -	1,392
Natural gas (MMcf)	2,672	2,947	2,860	2,358	8,165	1,500 -	1,700	9,665 -	9,865
Equivalent production (MBOE)	1,961	2,225	2,140	1,930	6,295	1,490 -	1,663	7,785 -	7,958
Equivalent daily production (BOEPD)	21,314	24,721	23,519	20,976	23,058	16,196 -	18,080	21,328 -	21,803
Production revenues (a):									
Crude oil	\$ 83.9	59.2	70.7	51.1	181.0	42.0 -	45.0	223.0 -	226.0
NGLs	\$ 7.4	5.4	5.2	3.3	13.8	2.0 -	2.5	15.8 -	16.3
Natural gas	\$ 10.2	8.6	7.3	6.3	22.1	3.5 -	4.5	25.6 -	26.6
Total product revenues	\$ 101.4	73.1	83.1	60.7	216.9	47.5 -	52.0	264.4 -	268.9
Crude oil derivative receipts (payments)	\$ 9.8	36.8	34.8	32.3	103.9	30.0 -	30.5	133.9 -	134.4
Natural gas derivative receipts (payments)	\$ 0.6	0.7	0.0	0.0	0.7	0.0 -	0.0	0.7 -	0.7
Total product revenues (including derivatives)	\$ 111.8	110.6	118.0	93.0	321.5	77.5 -	82.5	399.0 -	404.0
Operating expenses:									
Lease operating	\$ 11.4	11.6	10.9	11.3	33.8	8.6 -	9.2	42.4 -	43.0
Lease operating (\$ per BOE)	\$ 5.82	5.20	5.10	5.86	5.37	5.45 -	5.84	5.38 -	5.46
Gathering, processing and transportation costs	\$ 5.7	7.5	6.4	5.7	19.5	3.7 -	4.0	23.2 -	23.5
Gathering, processing and transportation costs (\$ per BOE)	\$ 2.90	3.37	2.98	2.93	3.10	2.35 -	2.54	2.95 -	2.99
Production and ad valorem taxes	\$ 5.5	4.7	5.0	3.5	13.1	2.7 -	2.9	15.8 -	16.0
Production and ad valorem taxes (percent of product revenues)	5.4%	6.4%	6.0%	5.7%	6.1%	5.4% -	5.8%	5.9% -	6.0%
General and administrative:									
Recurring general and administrative	\$ 7.1	10.6	9.4	8.2	28.2	8.0 -	9.0	36.2 -	37.2
Non-recurring general and administrative	\$ (0.0)	0.0	1.2	0.8	2.0	0.0 -	0.5	2.0 -	2.5
Share-based compensation	\$ (1.1)	1.4	0.9	0.4	2.7	1.1 -	1.1	3.8 -	3.8
Total reported G&A	\$ 6.0	12.0	11.5	9.4	32.9	9.1 -	10.6	42.0 -	43.5
Exploration:									
Total reported exploration	\$ 3.1	5.9	4.4	1.7	11.9	0.5 -	1.0	12.4 -	12.9
Drilling rig termination charges	\$ 0.0	3.6	2.0	0.5	6.2	0.5 -	1.0	6.7 -	7.2
Unproved property amortization	\$ 1.9	2.0	2.0	0.9	4.9	0.0 -	1.0	4.9 -	5.9
Depreciation, depletion and amortization	\$ 84.7	90.8	85.4	76.9	253.1	63.0 -	64.0	316.1 -	317.1
Depreciation, depletion and amortization (\$ per BOE)	\$ 43.18	40.81	39.91	39.82	40.20	39.96 -	40.59	40.15 -	40.28
Adjusted EBITDAX (b)	\$ 84.8	77.6	85.5	65.0	228.1	52.0 -	56.0	280.1 -	284.1
Capital expenditures:									
Drilling and completion	\$ 229.2	134.1	88.1	39.9	262.1	34.0 -	39.5	296.1 -	301.6
Lease acquisitions	\$ (1.5)	8.8	5.3	(0.5)	13.6	0.5 -	2.0	14.1 -	15.6
Seismic (c)	\$ 0.3	0.3	0.3	0.3	0.8	0.0 -	0.0	0.8 -	0.8
Pipeline, gathering, facilities and other	\$ 9.1	3.3	0.7	0.2	4.2	1.0 -	2.0	5.2 -	6.2
Total capital expenditures	\$ 237.1	146.5	94.4	39.8	280.7	35.5 -	43.5	316.2 -	324.2
End of period debt outstanding	\$ 1,110.0	1,237.0	1,287.0	1,215.0	1,215.0	1,230.0 -	1,245.0	1,230.0 -	1,245.0
Interest expense:									
Total reported interest expense	\$ 21.1	22.0	23.0	23.0	68.0	24.0 -	24.3	92.0 -	92.3
Cash interest expense	\$ 20.0	20.9	21.8	21.8	64.5	23.0 -	23.7	87.5 -	88.2
Preferred stock dividends paid	\$ 7.6	6.1	6.1	6.1	18.2	0.0 -	0.0	18.2 -	18.2
Effective tax rate	23.9%	-0.2%	-0.1%	-2.5%	0.4%				

(a) Assumes average benchmark prices of \$44.93 per barrel for crude oil and \$2.56 per MMBtu for natural gas in the fourth quarter of 2015, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments. NGL realized pricing is assumed to be \$8.55 per barrel in the fourth quarter of 2015, or approximately 19% of the benchmark crude oil price.

(b) Adjusted EBITDAX is not a measure of financial performance under GAAP and should not be considered as a measure of liquidity or as an alternative to net income.

(c) Seismic expenditures are also reported as a component of exploration expense and as a component of net cash provided by operating activities.

PENN VIRGINIA CORPORATION
GUIDANCE TABLE - unaudited - (continued)

Note to Guidance Table:

The following table shows our current derivative positions.

	<u>Instrument Type</u>	<u>Average Volume Per Day</u>	<u>Weighted Average Price</u>	
			<u>Floor/ Swap / Option</u>	<u>Ceiling</u>
Crude oil:		(barrels)	(\$ / barrel)	
Fourth quarter 2015	Collars	3,000	86.67	94.73
Fourth quarter 2015	Swaps	8,000	91.06	
Fourth quarter 2015	Sold Puts (a)	5,000	70.00	
First quarter 2016	Swaps	6,000	80.41	
Second quarter 2016	Swaps	6,000	80.41	
Third quarter 2016	Swaps	6,000	80.41	
Fourth quarter 2016	Swaps	6,000	80.41	

(a) These "lower" puts were sold at a strike price of \$70 per barrel. If the price of WTI oil goes below \$70 per barrel, the cash receipts on other 2015 derivatives will be limited to the difference between the swap / floor price and \$70 per barrel.

We estimate that, excluding the derivative positions described above, for every \$10.00 per barrel increase or decrease in the crude oil price, operating income for the fourth quarter of 2015 would increase or decrease by approximately \$9.1 million. In addition, we estimate that, excluding the derivative positions described above, for every \$1.00 per MMBtu increase or decrease in the natural gas price, operating income for the fourth quarter of 2015 would increase or decrease by approximately \$1.5 million. This assumes that crude oil prices, natural gas prices and inlet volumes remain constant at anticipated levels. These estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.