May 11, 2015

Penn Virginia Corporation Announces First Quarter 2015 Results and Provides Updates of 2015 Guidance and Operations

16% Sequential Growth in Total Production and 23% Sequential Growth in Eagle Ford Production

25% Decrease in Average Eagle Ford Well Cost Since Early Fourth Quarter 2014

Continued Solid Well Results From the Upper Eagle Ford (Marl) and Lower Eagle Ford

Borrowing Base of $425 Million and Relaxed Leverage Covenants

RADNOR, Pa., May 11, 2015 (GLOBE NEWSWIRE) -- Penn Virginia Corporation (NYSE:PVA) today reported financial results for the three months ended March 31, 2015 and provided updates of its operations and 2015 capital plan and guidance.

Key Highlights

First quarter 2015 results compared, as applicable, to fourth quarter 2014 results were as follows:

- Total production during the first quarter was 2.2 million barrels of oil equivalent (MMBOE), or 24,721 barrels of oil equivalent (BOE) per day (BOEPD), a 16% sequential increase compared to 21,314 BOEPD.
  - Total production increased 17% over the first quarter of 2014 and 29%, pro forma to exclude volumes from Mississippi properties sold in July 2014.
  - Eagle Ford production was 21,390 BOEPD, a 23% sequential increase compared to 17,459 BOEPD.
- Realized oil and gas prices were $71.79 per barrel and $3.14 per Mcf, compared to $77.99 per barrel and $4.03 per Mcf, including oil and gas derivatives.
- Product revenues were $110.6 million, compared to $111.8 million, including oil and gas derivatives.
- Drilling and completion costs in the Eagle Ford, including facilities, have decreased by approximately $2.5 million per well, or 25%, from early fourth quarter 2014.
- Unit production costs, including lease operating expense, gathering, processing and transportation expenses and production and ad valorem taxes, decreased to $10.68 per BOE from $11.52 per BOE.
- Adjusted EBITDAX, a non-GAAP (generally accepted accounting principles) measure, was $77.6 million, compared to $84.8 million.
- As a result of our active Upper Eagle Ford drilling program, 11 wells were turned in line since the end of 2014.
  - Over the past 12 months, 23 Upper Eagle Ford wells have been brought on line

    - with an initial potential (IP) rate of 1,223 BOEPD and a 30-day average rate, for the 21 applicable wells, of 942 BOEPD.
- The borrowing base under our revolving credit facility (Revolver) was recently re-determined to $425 million.
    - Maximum leverage ratio covenant was relaxed through maturity in September 2017 and a new covenant was added for senior secured debt.
    - At March 31, 2015, both ratios were well within the applicable covenants.
- At March 31, 2015, our pro forma financial liquidity was approximately $265 million after accounting for the borrowing base re-determination.

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

H. Baird Whitehead, President and Chief Executive Officer stated, "While continuing to grow production, our primary focus during the past two quarters has been on cutting well costs and improving operational execution. We have made significant progress on both fronts as drilling and completion costs have dropped by approximately 25%, unit production costs have declined approximately 7% and the execution of our drilling and completion program has been much better. For example, during the fourth and first quarters, we stimulated over 1,400 frac stages at almost a 100% operational success rate. Our first quarter production, which was up 16% from the fourth quarter, was in line with guidance and reflected our improved execution. As a result, our 2015 production guidance remains unchanged."

Mr. Whitehead continued, "We had an active Eagle Ford completion program in the first quarter, using three frac crews to bring on line a significant number of uncompleted wells from the eight-rig drilling program we operated for much of the second half of 2014. As a result, our Eagle Ford production increased by 23% over the fourth quarter. During the first quarter, our oil and gas hedges enabled us to partially offset lower commodity prices and maintain solid cash margins. While commodity futures prices have shown improvement recently, our drilling program remains focused on higher return opportunities in both the Lower and Upper Eagle Ford. Lastly, we are pleased with the outcome of our Revolver's borrowing base re-determination and the negotiation of a new covenant package."

First Quarter 2015 Results

Overview of Results

Operating loss was $57.9 million in the first quarter of 2015, compared to operating loss of $14.1 million in the fourth quarter of 2014, excluding $667.8 million of impairments of our East Texas and Oklahoma properties. This decrease was due primarily to a $27.6 million decrease in product and other revenues and increased operating expenses of $16.1 million, which are explained in more detail later in the release.

Net loss attributable to common shareholders for the first quarter was $63.2 million, or $0.88 per diluted share, compared to net loss of $423.8 million, or $5.90 per diluted share, in the prior quarter. Adjusted net loss attributable to common shareholders for the first quarter, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of other items that affect comparability to other periods, was $44.9 million, or $0.62 per diluted share, compared to a loss of $25.3 million, or $0.35 per diluted share, in the prior quarter.

Production

As shown in the table below, total production in the first quarter of 2015 was 24,721 BOEPD, compared to 21,314 BOEPD in the fourth quarter of 2014, with an approximate 3,900 BOEPD increase in the Eagle Ford.

	Total and Daily Equivalent Production for the Three Months Ended					
Region / Play Type	**Mar. 31, 2015**	**Dec. 31, 2014**	**Mar. 31, 2014**	**Mar. 31, 2015**	**Dec. 31, 2014**	**Mar. 31, 2014**
		(in MBOE)			(in BOEPD)	
Eagle Ford Shale	1,925	1,606	1,328	21,390	17,459	14,761
East Texas	173	201	215	1,925	2,181	2,394
Mid-Continent(1)	121	147	174	1,343	1,604	1,931
Other	6	7	184	63	70	2,047
Totals	**2,225**	**1,961**	**1,902**	**24,721**	**21,314**	**21,133**
Pro Forma Totals(2)	**2,225**	**1,961**	**1,724**	**24,721**	**21,314**	**19,153**

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

(1) Third quarter 2014 Mid-Continent volumes included approximately 109 MBOE (1,180 BOEPD) related to the settlement of litigation.

(2) Pro forma to exclude volumes from Mississippi properties sold in July 2014 and the third quarter 2014 Mid-Continent adjustment.

Product Revenues

Total product revenues decreased 28% to $73.1 million, or $32.87 per BOE, in the first quarter of 2015, from $101.4 million, or $51.73 per BOE, in the fourth quarter of 2014 due primarily to the 36% decrease in the realized oil equivalent price, partially offset by a 16% increase in daily production. Including derivatives, total product revenues were $110.6 million, or $49.72 per BOE, in the first quarter of 2015, compared to $111.8 million, or $57.04 per BOE, in the fourth quarter of 2014. For the first quarter, the realized oil price decreased by 37%, the realized natural gas price decreased by 24% and the realized NGL price decreased by 42% compared to the fourth quarter of 2014.

Operating Expenses

As discussed below, first quarter 2015 total direct operating expenses, excluding share-based compensation and non-recurring expenses, increased by $4.7 million to $34.4 million, or $15.45 per BOE produced, compared to $29.7 million, or $15.14 per BOE, in the fourth quarter of 2014.

- Lease operating expense increased by $0.2 million to $11.6 million, or $5.20 per BOE, from $11.4 million, or $5.83 per BOE, due to higher production levels, but unit costs decreased due to lower compression costs per BOE and a reduction in subsurface maintenance.

- Gathering, processing and transportation expense increased by $1.8 million to $7.5 million, or $3.37 per BOE, from $5.7 million, or $2.90 per BOE, due to higher gas volumes and gathering and compression charges for natural gas and NGL production in the Eagle Ford.
- Production and ad valorem taxes decreased by $0.8 million to $4.7 million, or 6.4% of product revenues, from $5.5 million, or 5.4% of product revenues, due to the decreases in commodity prices.
- General and administrative (G&A) expense, excluding share-based compensation and non-recurring expenses, increased by $3.5 million to $10.6 million, or $4.77 per BOE, from $7.1 million, or $3.62 per BOE in the fourth quarter. The increase in recurring G&A expense was due primarily to a $2.8 million increase in incentive compensation expense from a credit of $0.9 million to $1.9 million of expense in the first quarter.

Depletion, depreciation and amortization (DD&A) expense increased by $6.1 million to $90.8 million from $84.7 million due to higher production volumes, but the DD&A per BOE decreased from $43.18 per BOE in the fourth quarter to $40.81 per BOE in the first quarter.

Capital Expenditures

During the first quarter of 2015, capital expenditures were $147 million, a decrease of $90 million, or 38%, compared to $237 million in the fourth quarter of 2014, consisting of:

- $134 million for drilling and completion activities, compared to $229 million.
- $13 million for pipeline, gathering, facilities, seismic, leasehold acquisition and other capital expenditures, compared to $8 million.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of March 31, 2015, we had total debt of $1,237 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 $162 million drawn under our revolving credit facility (Revolver). In May 2015, the borrowing base under our Revolver was reduced from $500 million to $425 million, which was higher than the $400 million borrowing base we had guided to. Together with cash and equivalents of $4 million and net of letters of credit of $2 million, our pro forma financial liquidity was $265 million at March 31, 2015.

Our leverage ratio under the Revolver at March 31, 2015 was 3.5 times trailing twelve months' Adjusted EBITDAX of $355 million. In connection with the decrease in the borrowing base, the maximum leverage ratio allowable under the Revolver was amended to increase from 4.00 times to 4.75 times through March 31, 2016, to increase again to 5.25 times through June 30, 2016, to increase again to 5.50 times through December 31, 2016, to decrease to 4.50 times through March 31, 2017 and to decrease to 4.00 times through maturity in September 2017. A new covenant was added for outstanding obligations under the Revolver, with a maximum allowable ratio of 2.75 times through March 31, 2017. At March 31, 2015, this ratio was 0.5 times.

During the first quarter, interest expense was $22.0 million, of which $20.9 million was cash interest expense, compared to $21.1 million in the fourth quarter, of which $20.0 million was cash interest expense. In addition, during the first quarter, we paid $6.1 million in preferred stock dividends, compared to $7.6 million in the fourth quarter.

During the first quarter, derivatives income was $22.9 million, compared to derivatives income of $154.1 million in the fourth quarter. First quarter 2015 cash settlements of derivatives resulted in net cash receipts of $37.5 million, compared to $10.4 million of net cash receipts in the fourth quarter.

Derivatives Update

To support our operating cash flows, we hedge a portion of our oil and natural gas production at pre-determined prices or price ranges. Currently, we have hedged 13,000 barrels of daily crude oil production during the second quarter of 2015, or about 85% to 90% of our expected oil production, at a weighted average floor/swap price of $90.48 per barrel, and we have hedged 11,000 barrels of daily crude oil production during the second half of 2015, or about 70% to 80% of our expected oil production, at a weighted average floor/swap price of $89.86 per barrel. We have sold puts for 6,000 barrels of daily crude oil production during the second quarter of 2015 and have sold puts for 5,000 barrels of daily crude oil production during the second half of 2015, with all puts sold at a strike price of $70.00 per barrel. For 2016, we have hedged 4,000 barrels of daily crude oil production at a weighted average floor/swap price of $88.12 per barrel. We currently do not have any natural gas hedges.

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

Full-Year 2015 Guidance

Full-year 2015 guidance highlights are as follows:

- Production is expected to be 23,800 to 26,200 BOEPD, unchanged from previous guidance.
    - 2015 crude oil production guidance is 14,000 to 15,400 barrels of oil per day (BOPD), compared to previous guidance of 13,800 to 15,100 BOPD.
    - Production in the second quarter of 2015 is expected to range between 24,000 and 26,000 BOEPD.
- Product revenues, excluding the impact of any hedges, are expected to be $320 to $350 million, compared to previous guidance of $312 to $343 million.
    - Our crude oil revenue estimate assumes realized pricing of West Texas Intermediate (WTI) crude oil benchmark pricing of $56.15 per barrel (ranging from $55 per barrel in the second quarter to $62 per barrel in the fourth quarter of 2015), with realized pricing of $3 to $4 per barrel less. Benchmark (Henry Hub) natural gas pricing is assumed to be $2.75 per Mcf (ranging from $2.57 per Mcf in the second quarter to $2.81 per Mcf in the fourth quarter of 2015), with an approximate $0.07 per Mcf negative differential, while NGL pricing is assumed to be 26% of the WTI price.
    - Cash receipts from the settlement of derivatives are expected to be $119 to $123 million based on the foregoing assumptions.
- Adjusted EBITDAX, a non-GAAP measure, is expected to be $300 to $340 million, unchanged from previous guidance.
    - Net cash provided by operating activities, including expected working capital changes, is expected to be $165 to $185 million.
- Capital expenditures are expected to be $325 to $370 million, compared to previous guidance of $295 to $345 million.

- Drilling and completion capital expenditures, which will continue to be focused on the Upper Eagle Ford, are expected to be $310 to $350 million, compared to previous guidance of $270 to $310 million. Despite the decrease in well costs from the fourth quarter, guidance increased by $40 million due to $25 million of completion capital expenditures deferred into 2015 associated with an active eight rig drilling program for much of the second half of 2014 and an incremental $15 million attributable to an increase in net wells planned for the remainder of the year.
- Pipeline, gathering, facilities, seismic and other capital expenditures are expected to be $5 to $8 million, compared to previous guidance of $10 to $15 million.
- Lease acquisition capital expenditures are expected to be $10 to $11 million, compared to previous guidance of $15 to $20 million.

Please see the Guidance Table included in this release for guidance estimates for second quarter and full-year 2015. These estimates are meant to provide guidance only and are subject to revision as our operating environment changes.

Eagle Ford Shale Operational Update

First Quarter 2015 Update

First quarter production from our Eagle Ford operations was 21,390 BOEPD, a 23% increase over the 17,459 BOEPD produced in the fourth quarter of 2014. Approximately 68% of our first quarter Eagle Ford production was from crude oil, 17% was from NGLs and 15% was from natural gas.

Well Cost Reductions

Well costs declined by approximately $2.5 million, or 25%, from approximately $10.3 million for wells spud in October and November of 2014 to approximately $7.7 million for wells spud in February and March of 2015. Completion costs for wells declined by approximately 33%, or $1.8 million, over that time interval, while drilling costs declined by approximately 17%, or $0.7 million. The decrease in completion costs was due to ongoing optimization of completion design and improved stimulation pricing. We expect to see additional decreases in drilling costs for the balance of the year as our cost reduction initiatives continue.

So far in 2015, we have increased our footage drilled per day by approximately 10% over 2014. We are now setting both our surface and intermediate casings at shallower depths and using water-based mud instead of oil-based mud in the intermediate section of our 3-string wells. We started testing this design in 2014 and are now starting to see the cost benefits. Additionally, we plan to use all remaining inventory of production casing by the end of June and are in the process of re-bidding production casing to obtain more competitive prices. By implementing these changes, as well as others, we expect well costs for the rest of 2015 to average between $7.0 million for 2-string wells and $8.3 million for 3-string wells.

Below are the results and statistics for Eagle Ford wells over the past eight quarters: (3)

Averages

	Gross/ Net Wells	Lateral Length	Frac Stages	Proppant	Peak Gross Daily Production Rates(4) Oil Rate	Equivalent Rate	Oil Percentage	30-Day Average Gross Daily Production Rates(4) Oil Rate	Equivalent Rate	Oil Percentage
		Feet		*lbs.*	*BOPD*	*BOEPD*		*BOPD*	*BOEPD*	
Time Period										
2013 - 2nd quarter	18 / 11.6	5,626	22.6	5,225,262	1,083	1,262	86%	657	787	85%
2013 - 3rd quarter	16 / 9.7	5,375	21.9	6,162,808	1,110	1,268	88%	725	840	86%
2013 - 4th quarter	17 / 8.6	5,623	23.7	7,665,586	1,289	1,474	88%	890	1,034	87%
2014 - 1st quarter	17 / 12.8	5,687	24.8	7,630,763	1,080	1,375	80%	649	793	82%
2014 - 2nd quarter	21 / 12.5	5,487	25.2	9,218,820	1,191	1,472	81%	736	903	83%
2014 - 3rd quarter	23 / 12.2	5,756	27.0	10,038,484	1,079	1,268	85%	676	788	86%
2014 - 4th quarter	19 / 14.9	5,536	25.8	10,222,539	832	1,230	68%	618	910	69%
2015 - 1st quarter(5)	33 / 18.9	6,226	26.4	7,989,889	1,054	1,288	82%	684	809	86%
Totals and averages(5)	**164/101.2**	**5,730**	**25.0**	**8,166,530**	**1,085**	**1,326**	**82%**	**701**	**853**	**83%**
Operating Area										
Upper Eagle Ford	23 / 19.9	6,039	26.2	9,176,392	751	1,223	64%	587	942	65%
Lavaca "Beer Area"	38 / 17.9	5,997	26.8	9,392,451	1,345	1,637	82%	841	1,014	83%
Rock Creek / Bozka	13 / 5.8	5,671	25.8	9,074,592	1,268	1,440	88%	900	1,016	89%
Peach Creek	23 / 10.3	5,555	24.6	7,772,141	1,339	1,488	90%	820	905	91%
Shiner	32 / 26.6	5,226	22.4	6,548,354	937	1,237	76%	534	709	75%
Shallow Gonzales	37 / 22.1	5,805	24.6	7,512,656	933	1,006	93%	611	662	92%
Totals and averages(5)	**164/101.2**	**5,730**	**25.0**	**8,166,530**	**1,085**	**1,326**	**82%**	**701**	**853**	**83%**

(3) Excludes one Upper Eagle Ford well that had mechanical issues, as previously disclosed.

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

(5) 30-day information is available for 20 wells since the end of the fourth quarter of 2014 and for 122 wells since April 1, 2013. Includes wells turned in line after March 31, 2015.

Since the end of the fourth quarter of 2014, we have turned in line 33 (18.9 net) operated wells. As a group, these 33 wells had an average IP rate of 1,288 BOEPD over an average of 26.4 frac stages, with 82% of production from crude oil. Of these 33 wells, 28 wells with sufficient production history had a 30-day average rate of 813 BOEPD, with 86% of production from crude oil. The average amount of proppant per stage for these 33 wells was approximately 303,000 pounds. The average IP rate increased 5% from 1,230 BOEPD in the fourth quarter of 2014 and the 30-day average rate decreased 11% from 910 BOEPD. However, the average oil IP and oil 30-day average rates increased 27% and 11% from the fourth quarter of 2014 to 1,054 BOPD and 684 BOPD, respectively.

Among these 33 wells, the more notable results for Lower Eagle Ford wells included the Dingo #4H (IP of 2,326 BOEPD and 30-day rate of 1,186 BOEPD), Dingo Hunter #2H (IP of 2,157 BOEPD and 30-day rate of 955 BOEPD), Dingo Hunter #3H (IP of 1,424 BOEPD and 30-day rate of 946 BOEPD), Hefe Hunter #4H (IP of 2,313 BOEPD and 30-day rate of 1,538 BOEPD), Hefe Hunter #2H (IP of 1,913 BOEPD and 30-day rate of 973 BOEPD), RBK #1H (IP of 1,912 BOEPD), RBK #3H (IP of 1,562 BOEPD), Lager #2H (IP of 1,713 BOEPD and 30-day rate of 1,103 BOEPD), Platypus Hunter #3H (IP of 1,594 and 30-day rate of 1,015 BOEPD), Rock Creek Ranch Fletcher #3H (IP of 1,508 BOEPD and 30-day rate of 948 BOEPD) and the Rock Creek Ranch Jane #2H (IP of 796 BOEPD and 30-day rate of 1,028 BOEPD).

Among these 33 wells, the more notable Upper Eagle Ford results included the Othold Martinsen #2H (IP of 1,740 BOEPD and 30-day rate of 1,285 BOEPD), the Othold Martinsen #1H (IP of 1,469 BOEPD and 30-day rate of 1,110 BOEPD), the Douglas Raab #3H (IP of 1,734 BOEPD and 30-day rate of 1,092 BOEPD), the Douglas Raab #2H (IP of 1,334 BOEPD and 30-day rate of 954 BOEPD) and the Dingo #3H (IP of 1,424 BOEPD and 30-day rate of 946 BOEPD).

Upper Eagle Ford (Marl) Shale Update

Our excellent overall results observed to date in the Upper Eagle Ford continue to demonstrate the significant potential we believe this zone has across much of our acreage position. As we complete additional Upper Eagle Ford wells and test our acreage, the production results of those wells continues to support our belief that the Upper and Lower Eagle Ford are acting as separate reservoirs. Since March 2014, we have completed and turned in line 24 Upper Eagle Ford wells, including one well that had a mechanical issue. The average IP rate for the 23 wells that did not encounter a mechanical issue was 1,223 BOEPD (64% oil) and the average 30-day rate for 21 of these 23 wells with sufficient production history was 942 BOEPD (65% oil).

Notable cumulative production results for Upper Eagle Ford Shale wells completed in the fourth quarter of 2014 and first quarter of 2015 include the Welhausen #B5H (cumulative production of 92,570 BOE over 136 days), the Welhausen #B4H (107,239 BOE over 135 days), the Welhausen #B3H (85,957 BOE over 129 days), the Welhausen #A3H (97,766 BOE over 120 days), the Welhausen #B2H (80,967 BOE over 119 days), the Douglas Raab #3H (79,807 BOE over 113 days), the Dingo #3H (55,732 BOE over 76 days), the Othold Martinsen #1H (48,041 BOE over 54 days) and the Othold Martinsen #1H (47,992 BOE over 50 days).

The early results of the Upper Eagle Ford wells are encouraging and, due to these excellent results, we continue to plan to devote a significant portion of our remaining 2015 capital expenditures to drilling additional Upper Eagle Ford wells.

First Quarter 2015 Conference Call

A conference call and webcast, during which management will discuss first quarter 2015 financial and operational results, is scheduled for Tuesday, May 12, 2015 at 10:00 a.m. ET. Prepared remarks by H. Baird Whitehead, President and Chief Executive Officer, 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 59449147), 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 59449147. 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, 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; any impairments, write-downs or write-offs of our reserves or assets; the projected demand for and supply of oil, NGLs and natural gas; reductions in the borrowing base under our revolving credit facility; 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; our ability to maintain adequate financial liquidity and to access adequate levels of capital on reasonable terms; 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 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.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited

(in thousands, except per share data)

	Three months ended		Three Months ended
	March 31,		December 31,
	2015	2014	2014
Revenues			
Crude oil	$ 59,168	$ 105,576	$ 83,904
Natural gas liquids (NGLs)	5,396	9,373	7,353
Natural gas	8,571	18,203	10,185
Total product revenues	73,135	133,152	101,442
Gain (loss) on sales of property and equipment, net	(91)	56,826	474
Other	1,483	(113)	235
Total revenues	74,527	189,865	102,151
Operating expenses			
Lease operating	11,569	10,116	11,420
Gathering, processing and transportation (a)	7,498	3,249	5,689
Production and ad valorem taxes	4,689	7,305	5,485
General and administrative (excluding equity-classified share-based compensation) (b)	10,980	15,863	4,961
Total direct operating expenses	34,736	36,533	27,555
Share-based compensation - equity classified awards (c)	990	825	989
Exploration	5,887	8,636	3,068
Depreciation, depletion and amortization	90,790	72,187	84,676
Impairments	--	--	667,817
Total operating expenses	132,403	118,181	784,105
Operating income (loss)	(57,876)	71,684	(681,954)

Other income (expense)			
Interest expense	(22,013)	(22,534)	(21,115)
Derivatives	22,867	(15,662)	154,082
Other	(2)	1	(46)
Income (loss) before income taxes	(57,024)	33,489	(549,033)
Income tax (expense) benefit	(141)	(14,264)	131,339
Net income (loss)	(57,165)	19,225	(417,694)
Preferred stock dividends	(6,067)	(1,722)	(6,067)
Net income (loss) attributable to common shareholders	$ (63,232)	$ 17,503	$ (423,761)
Net income (loss) per share:			
Basic	$ (0.88)	$ 0.27	$ (5.90)
Diluted	$ (0.88)	$ 0.22	$ (5.90)
Weighted average shares outstanding, basic	71,820	65,611	71,790
Weighted average shares outstanding, diluted	71,820	85,744	71,790

	Three months ended March 31,		Three months ended December 31,
	2015	2014	2014
Production			
Crude oil (MBbls)	1,337	1,076	1,202
NGLs (MBbls)	397	227	314
Natural gas (MMcf)	2,947	3,593	2,672
Total crude oil, NGL and natural gas production (MBOE)	2,225	1,902	1,961
Prices			
Crude oil ($ per Bbl)	$ 44.26	$ 98.12	$ 69.82
NGLs ($ per Bbl)	$ 13.60	$ 41.27	$ 23.43
Natural gas ($ per Mcf)	$ 2.91	$ 5.07	$ 3.81
Prices - Adjusted for derivative settlements			
Crude oil ($ per Bbl)	$ 71.79	$ 96.00	$ 77.99
NGLs ($ per Bbl)	$ 13.60	$ 41.27	$ 23.43
Natural gas ($ per Mcf)	$ 3.14	$ 4.85	$ 4.03

(a) We have reclassified approximately $0.3 million of certain natural gas compression costs from lease operating expense to gathering, processing and transportation expenses for the three months ended March 31, 2014.

(b) Includes liability-classified share-based compensation expense (credit) attributable to our performance-based restricted stock units which are payable in cash upon the achievement of certain market-based performance metrics. A total of $0.4 million, $5.9 million and $(2.1) million and attributable to these awards is included in the three months ended March 31, 2015 and 2014 and December 31, 2014, respectively.

(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.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS - unaudited

(in thousands)

	As of	
	March 31, 2015	December 31, 2014
Assets		
Current assets	$ 281,884	$ 335,027
Net property and equipment	1,880,612	1,825,098
Other assets	36,155	40,115
Total assets	$ 2,198,651	$ 2,200,240
Liabilities and shareholders' equity		
Current liabilities	$ 245,066	$ 312,227
Revolving credit facility	162,000	35,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Debt issuance costs	(25,090)	(26,194)
Other liabilities and deferred income taxes	128,111	128,390
Total shareholders' equity	613,564	675,817
Total liabilities and shareholders' equity	$ 2,198,651	$ 2,200,240

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited

(in thousands)

	Three months ended March 31,		Three Months ended December 31,
	2015	2014	2014
Cash flows from operating activities			
Net income (loss)	$ (57,165)	$ 19,225	$ (417,694)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	90,790	72,187	84,676
Impairments	--	--	667,817
Accretion of firm transportation obligation	212	354	310
Derivative contracts:			
Net losses (gains)	(22,867)	15,662	(154,082)

Cash settlements, net	37,492	(3,057)	10,412
Deferred income tax expense (benefit)	141	14,064	(134,888)
(Gain) loss on sales of assets, net	91	(56,826)	(474)
Non-cash exploration expense	1,983	3,294	1,959
Non-cash interest expense	1,104	1,012	1,083
Share-based compensation (equity-classified)	990	825	989
Other, net	9	206	(231)
Changes in operating assets and liabilities	(7,228)	(386)	22,397
Net cash provided by operating activities	45,552	66,560	82,274
Cash flows from investing activities			
Capital expenditures - property and equipment	(168,994)	(159,804)	(229,108)
Proceeds from sales of assets, net	116	95,964	2,020
Net cash used in investing activities	(168,878)	(63,840)	(227,088)
Cash flows from financing activities			
Proceeds from revolving credit facility borrowings	127,000	85,000	35,000
Repayment of revolving credit facility borrowings	--	(101,000)	--
Dividends paid on preferred and common stock	(6,067)	(1,725)	(7,638)
Other, net	--	1,085	14
Net cash provided by (used in) financing activities	120,933	(16,640)	27,376
Net decrease in cash and cash equivalents	(2,393)	(13,920)	(117,438)
Cash and cash equivalents - beginning of period	6,252	23,474	123,690
Cash and cash equivalents - end of period	$ 3,859	$ 9,554	$ 6,252

PENN VIRGINIA CORPORATION

CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited

(in thousands)

	Three months ended March 31,		Three Months ended December 31,
	2015	2014	2014
Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Net income (loss) applicable to common shareholders, as adjusted"			
Net income (loss)	$ (57,165)	$ 19,225	$ (417,694)
Adjustments for derivatives:			
Net losses (gains)	(22,867)	15,662	(154,082)
Cash settlements, net	37,492	(3,057)	10,412
Adjustment for impairments	--	--	667,817
Adjustment for restructuring costs	(11)	12	(17)
Adjustment for rig termination charge	3,626	--	--
Adjustment for (gain) loss on sale of assets, net	91	(56,826)	(474)
Impact of adjustments on income taxes	45	18,830	(125,268)

Preferred stock dividends	(6,067)	(1,722)	(6,067)
Net loss applicable to common shareholders, as adjusted (a)	$ (44,856)	$ (7,876)	$ (25,373)
Net loss applicable to common shareholders, as adjusted, per share, diluted	$ (0.62)	$ (0.12)	$ (0.35)
Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"			
Net income (loss)	$ (57,165)	$ 19,225	$ (417,694)
Income tax benefit	141	14,264	(131,339)
Interest expense	22,013	22,534	21,115
Depreciation, depletion and amortization	90,790	72,187	84,676
Exploration	5,887	8,636	3,068
Share-based compensation expense (equity-classified awards)	990	825	989
EBITDAX	62,656	137,671	(439,185)
Adjustments for derivatives:			
Net losses (gains)	(22,867)	15,662	(154,082)
Cash settlements, net	37,492	(3,057)	10,412
Adjustment for impairments	--	--	667,817
Adjustment for (gain) loss on sale of assets, net	91	(56,826)	(474)
Adjustment for other non-cash items	212	354	310
Adjusted EBITDAX (b)	$ 77,584	$ 93,804	$ 84,798

(a) Net income (loss) applicable to common shareholders, as adjusted, represents net income (loss), less preferred stock dividends, adjusted to exclude the effects, net of income taxes, of non-cash changes in the fair value of derivatives, impairments, restructuring costs, rig termination charges and net gains and losses on the sale of assets. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes within our industry. Net income (loss) applicable to common shareholders, as adjusted, 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 loss applicable to common shareholders.

(b) Adjusted EBITDAX represents net income (loss) before income tax benefit, interest expense, depreciation, depletion and amortization expense, exploration expense and share-based compensation expense, further adjusted to exclude the effects of non-cash changes in the fair value of derivatives, impairments, net gains and losses on the sale of assets and other non-cash items. We believe this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes within our industry. 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 (loss). Pro forma Adjusted EBITDAX further adjusts Adjusted EBITDAX to include the pro forma EBITDAX from our Eagle Ford Shale acquisition in April 2013 and represents EBITDAX as defined in our revolving credit facility.

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 Quarter 2014	First Quarter 2015	Second Quarter	Second Half	Full-Year
Production:					
Crude oil (MBbls)	1,202	1,337	1,300 - 1,400	2,488 - 2,888	5,125 - 5,625
NGLs (MBbls)	314	397	425 - 450	803 - 878	1,625 - 1,725
Natural gas (MMcf)	2,672	2,947	2,750 - 3,100	5,924 - 7,230	11,621 - 13,277
Equivalent production (MBOE)	1,961	2,225	2,183 - 2,367	4,279 - 4,971	8,687 - 9,563
Equivalent daily production (BOEPD)	21,314	24,721	23,993 - 26,007	23,253 - 27,018	23,800 - 26,200
Production revenues (a):					
Crude oil	$ 83.9	59.2	66.0 - 70.0	139.8 - 160.8	265.0 - 290.0
NGLs	$ 7.4	5.4	5.0 - 7.0	13.1 - 13.6	23.5 - 26.0
Natural gas	$ 10.2	8.6	7.0 - 9.0	15.4 - 16.4	31.0 - 34.0
Total product revenues	$ 101.4	73.1	78.0 - 86.0	168.4 - 190.9	319.5 - 350.0
Crude oil derivative receipts (payments)	$ 9.8	36.8	33.0 - 35.0	48.2 - 50.2	118.0 - 122.0
Natural gas derivative receipts (payments)	$ 0.6	0.7	0.0 - 0.0	0.0 - 0.0	0.7 - 0.7
Total product revenues (including derivatives)	$ 111.8	110.6	111.0 - 121.0	216.6 - 241.1	438.2 - 472.7
Operating expenses:					
Lease operating	$ 11.4	11.6			44.0 - 46.0
Lease operating ($ per BOE)	$ 5.82	5.20			4.60 - 5.30
Gathering, processing and transportation costs	$ 5.7	7.5			32.5 - 35.0
Gathering, processing and transportation costs ($ per BOE)	$ 2.90	3.37			3.40 - 4.03
Production and ad valorem taxes	$ 5.5	4.7			20.0 - 21.5
Production and ad valorem taxes (percent of product revenues)	5.4%	6.4%			5.7% - 6.7%
General and administrative:					
Recurring general and administrative	$ 7.1	10.6			41.5 - 43.5
Non-recurring general and administrative	$ (0.0)	(0.0)			(0.0) - (0.0)
Share-based compensation	$ (1.1)	1.4			3.5 - 4.5
Total reported G&A	$ 6.0	12.0			45.0 - 48.0
Exploration:					
Total reported exploration	$ 3.1	5.9			9.5 - 10.0
Unproved property amortization	$ 1.9	2.0			5.0 - 5.2
Depreciation, depletion and amortization	$ 84.7	90.8			350.0 - 355.0
Depreciation, depletion and amortization ($ per BOE)	$ 43.18	40.81			36.60 - 40.87

Adjusted EBITDAX (b)	$ 84.8	77.6	75.0 - 85.0	147.4 - 177.4	300.0 - 340.0
Capital expenditures:					
Drilling and completion	$ 229.2	134.1	95.0 - 105.0	80.9 - 110.9	310.0 - 350.0
Lease acquisitions	$ (1.5)	8.8	0.3 - 0.5	0.9 - 1.7	10.0 - 11.0
Seismic (c)	$ 0.3	0.3	0.0 - 0.2	0.0 - 0.5	0.3 - 1.0
Pipeline, gathering, facilities and other	$ 9.1	3.3	0.5 - 1.3	1.2 - 2.4	5.0 - 7.0
Total capital expenditures	$ 237.1	146.5	95.8 - 107.0	83.0 - 115.5	325.3 - 369.0
End of period debt outstanding	$ 1,110.0	1,237.0			1,310.0 - 1,350.0
Interest expense:					
Total reported interest expense	$ 21.1	22.0	24.0 - 25.0	49.0 - 53.0	95.0 - 100.0
Cash interest expense	$ 20.0	20.9	23.0 - 23.8	46.8 - 50.8	90.7 - 95.5
Preferred stock dividends paid	$ 7.6	6.1	6.0 - 6.2	11.9 - 12.2	24.0 - 24.5
Effective tax rate	23.9%	-0.2%			

(a) Assumes average benchmark prices of $59.11 per barrel for crude oil and $2.67 per MMBtu for natural gas in the final three quarters 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 $15.25 per barrel in the final three quarters of 2015.

(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.

			Weighted Average Price	
	Instrument Type	**Average Volume Per Day**	**Floor/ Swap / Option**	**Ceiling**
Crude oil:		**(barrels)**	**($ / barrel)**	
Second quarter 2015	Collars	4,000	87.50	94.66
Third quarter 2015	Collars	3,000	86.67	94.73
Fourth quarter 2015	Collars	3,000	86.67	94.73
Second quarter 2015	Swaps	9,000	91.81	
Third quarter 2015	Swaps	8,000	91.06	
Fourth quarter 2015	Swaps	8,000	91.06	
First quarter 2016	Swaps	4,000	88.12	
Second quarter 2016	Swaps	4,000	88.12	

Third quarter 2016	Swaps	4,000	88.12
Fourth quarter 2016	Swaps	4,000	88.12
Second quarter 2015	Sold Puts (a)	6,000	70.00
Third quarter 2015	Sold Puts (a)	5,000	70.00
Fourth quarter 2015	Sold Puts (a)	5,000	70.00

(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 final three quarters of 2015 would increase or decrease by approximately $33.3 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 final three quarters of 2015 would increase or decrease by approximately $7.9 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.

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PENN VIRGINIA CORPORATION

Source: Penn Virginia Corporation