Penn Virginia Corporation Announces Third Quarter 2014 Results

29.10.2014 | GlobeNewswire

Total Production Up 4% Quarter-Over-Quarter, Exceeding Guidance

Eagle Ford Production Up 8% Quarter-Over-Quarter

Adjusted EBITDAX Increased to $98 Million

Borrowing Base Increased to $500 Million

RADNOR, Pa., Oct. 29, 2014 (GLOBE NEWSWIRE) -- Penn Virginia Corp. (NYSE:PVA) today reported financial results for the three months ended September 30, 2014 and provided updates of its operations and 2014 guidance.

Key Third Quarter Highlights

Production

- Total production increased 4% to 22,706 barrels of oil equivalent per day (BOEPD) compared to the prior quarter, exceeding the upper end of guidance by 3%.
  - Eagle Ford Shale production increased 8% to 16,929 BOEPD compared to the prior quarter.
  - Pro forma for the sale of Mississippi properties in July, total production increased 11% to 22,054 BOEPD.
  - Oil and NGL volumes were 74% of total equivalent production compared to 70% in the prior quarter.

Operations – Eagle Ford

- Initial potential (IP) from operated horizontal wells (excluding shallow wells) averaged 1,350 BOEPD, including five wells with IPs of over 1,900 BOEPD.
- 12 (8.5 net) wells are currently completing or flowing back (including six (5.7 net) Upper Eagle Ford wells), 14 (8.5 net) wells are currently waiting on completion (including six (5.2 net) Upper Eagle Ford wells) and eight (6.3 net) operated wells are currently being drilled (including three (2.9 net) Upper Eagle Ford wells).
- Eagle Ford acreage now approximates 145,500 (104,300 net) acres.
  - Approximately 2,500 net acres were added since the last quarterly report at an average cost of $1,700 per acre.

Financial Resources and Liquidity

- Adjusted EBITDAX, a non-GAAP (generally accepted accounting principles) measure, grew to $97.7 million in the third quarter from $95.0 million in the prior quarter.
- Borrowing base under our revolving credit facility increased to $500 million, providing pro forma financial liquidity at quarter end of $622 million.
- Leverage ratio significantly improved at quarter end.

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, "In the third quarter of 2014, production exceeded the upper end of guidance, supporting strong cash flows and margins in line with our expectations. Our continued focus on improving execution is showing results as we transition to using larger production casing. This change is driving fewer operational delays and eliminating inefficiencies with our service providers. Based on these improvements, we are reaffirming production guidance for the fourth quarter of 2014. In addition, we have begun completions of our most recently drilled Upper Eagle Ford wells and we believe the play is highly prospective across our acreage.

Whitehead added, "With respect to 2015, we expect to see continued growth in production and cash flow, but we are reassessing our previously announced preliminary guidance and our level of capital expenditures for 2015 in light of the current and projected oil price environment. We plan to release updated 2015 guidance in mid-December after our budget is finalized. Importantly, our current financial liquidity, together with future operating cash flows, is sufficient to fully fund any reasonable capital program we might consider in this evolving environment. Also, in view of our depressed share price and to expand our capital allocation options, we will seek an amendment to our credit facility to permit us to repurchase our common stock under appropriate circumstances."

Third Quarter 2014 Results

Overview of Results

Operating income increased $3.0 million to $29.3 million, excluding $63.5 million of gains on the sale of assets and $6.1 million of impairments, in the third quarter of 2014 from $26.3 million, excluding $117.9 million of impairments, in the second quarter of 2014. This increase was due primarily to a $5.4 million increase in product revenues, a $1.4 million decrease in exploration expense, a $1.2 million decrease in share-based compensation expenses and a $1.2 million decrease in recurring general and administrative (G&A) expense. The effect of these favorable changes was partially offset by a $4.4 million increase in lease operating, gathering, processing and transportation expenses and production and ad valorem taxes and a $0.6 million increase in depletion, depreciation and amortization (DD&A) expense.

Net income attributable to common shareholders for the third quarter was $81.1 million, or $0.87 per diluted share, compared to net loss of $105.9 million, or $1.59 per diluted share, in the prior quarter. Adjusted net loss attributable to common shareholders for the third 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 $7.4 million, or $0.10 per diluted share, compared to a loss of $4.3 million, or $0.07 per diluted share, in the prior quarter.

Product Revenues

Total product revenues increased 4% to $141.9 million, or $67.91 per barrel of oil equivalent (BOE), in the third quarter of 2014, from $136.4 million, or $68.81 per BOE, in the second quarter due primarily to a 5% increase in total production, partially offset by an overall 1% decrease in the weighted average product price per BOE. For the third quarter, the realized oil price decreased by 5%, the realized natural gas price decreased by 7% and the realized natural gas liquid (NGL) price increased by 3% over the second quarter. Oil and NGL revenues were $128.5 million in the third quarter, a 7% increase compared to $120.1 million in the second quarter due to a 13% increase in combined oil and NGL production, partially offset by a 5% decrease in combined oil and NGL prices. Oil and NGL revenues were 91% of product revenues in the third quarter, compared to 88% in the second quarter. Natural gas revenues were $13.4 million in the third quarter, an 18% decrease compared to $16.3 million in the second quarter, primarily due to the sale of our Mississippi Selma Chalk properties in July 2014.

Production

As shown in the table below, total production in the third quarter of 2014 was 22,706 BOEPD, compared to 21,786 BOEPD in the second quarter of 2014. As a percentage of total equivalent production, oil and NGL volumes were 74% in the third quarter of 2014, compared to 70% in the second quarter of 2014.

Region / Play Type	Total and Daily Equivalent Production for the Three Months Ended Sept. 30, 2014 (in MBOE)	June 30, 2014	Mar. 31, 2014	Sept. 30, 2014 (in BOEPD)	June 30, 2014	Mar. 31, 2014
Eagle Ford Shale	1,557	1,421	1,329	16,929	15,618	14,761
East Texas	208	220	215	2,257	2,417	2,394
Mid-Continent	258	161	174	2,802	1,770	1,931
Mississippi / Other	66	180	184	719	1,981	2,047
Totals	2,089	1,983	1,902	22,706	21,786	21,133
Pro Forma Totals[(1)]	2,029	1,809	1,724	22,054	19,872	19,153

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

[(1)] Pro forma to exclude volumes from Mississippi properties sold at the end of July 2014.

Operating Expenses

As discussed below, third quarter 2014 total direct operating expenses, excluding share-based compensation and non-recurring expenses, increased by $3.2 million to $38.5 million, or $18.41 per BOE produced, compared to $35.3 million, or $17.80 per BOE, in the second quarter of 2014.

- Lease operating expense increased by $2.9 million to $15.3 million, or $7.32 per BOE, from $12.4 million, or $6.26 per BOE, due to higher compression, subsurface equipment and workover costs.
- Gathering, processing and transportation expense increased by $1.4 million to $4.9 million, or $2.34 per BOE, compared to $3.5 million, or $1.78 per BOE, due to higher processing costs.
- Production and ad valorem taxes increased by $0.2 million to $7.7 million, or 5.4% of product revenues, from $7.5 million, or 5.5% of product revenues, due to higher production.
- G&A expense, excluding share-based compensation and non-recurring expenses of $0.9 million, decreased by $1.2 million to $10.6 million, or $5.06 per BOE, from $11.8 million, or $5.98 per BOE, excluding share-based compensation and non-recurring expenses of $3.0 million. The decrease in recurring G&A expense was due to reduced office rent, telecommunications, information technology and other corporate expenses. The decrease in share-based compensation expenses was due to a lower common stock price in the third quarter of 2014.

Exploration expense decreased $1.4 million from the second quarter to $2.0 million in the third quarter, due primarily to lower unproved leasehold amortization expense.

DD&A expense increased by $0.6 million to $72.0 million, or $34.47 per BOE, in the third quarter, from $71.4 million, or $36.03 per BOE, in the second quarter, due to higher production, partially offset by lower depletion rates.

In the third quarter, we incurred a $6.1 million impairment charge in the Mid-Continent with respect to an exploratory prospect and we recorded a $63.5 million gain on the sale of assets due primarily to our sale of rights to construct an oil gathering system in south Texas.

Capital Expenditures

During the third quarter of 2014, capital expenditures were $205 million, an increase of $35 million, or 21%, compared to $170 million in the second quarter of 2014, consisting of:

- $149 million for drilling and completion activities, compared to $154 million in the second quarter;
- $51 million for leasehold acquisitions, compared to $13 million in the second quarter; and
- $5 million for pipeline, gathering, facilities, seismic and other, compared to $3 million in the second quarter.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of September 30, 2014, we had total debt of $1,075 million, consisting of $300 million principal amount of 7.25% senior unsecured notes due 2019 and $775 million principal amount of 8.50% senior unsecured notes due 2020. At September 30, 2014, we had a zero balance under our revolving credit facility (Revolver). In October 2014, the borrowing base under our Revolver was increased from $438 million to $500 million. Together with cash and equivalents of $124 million and net of letters of credit of approximately $2 million at September 30, 2014, our pro forma financial liquidity was approximately $622 million at September 30, 2014. Our leverage ratio under the Revolver at September 30, 2014 was 2.6 times trailing twelve months' pro forma Adjusted EBITDAX of approximately $372 million, compared to 3.1 times at June 30, 2014.

During the third quarter, interest expense was $22.0 million, of which $20.9 million was cash interest expense, compared to $23.2 million in the second quarter, of which $22.2 million was cash interest expense.

During the third quarter, derivatives income was $66.5 million, compared to derivatives loss of $42.7 million in the second quarter. Third quarter 2014 cash settlements of derivatives resulted in net cash outlays of $7.6 million, compared to $7.2 million of net cash outlays in the second quarter.

Pricing

Our third quarter 2014 realized oil price was $95.19 per barrel, compared to $100.16 per barrel in the second quarter of 2014. Our third quarter 2014 realized NGL price was $31.76 per barrel, compared to $30.85 per barrel in the second quarter. Our third quarter 2014 realized natural gas price was $4.17 per thousand cubic feet (Mcf), compared to $4.51 per Mcf in the second quarter. Adjusting for oil and gas hedges, our third quarter 2014 effective oil price was $89.08 per barrel and our third quarter 2014 effective natural gas price was $4.19 per Mcf, or a decrease of $6.11 per barrel from the realized oil price and an increase of $0.02 per Mcf from the realized gas price.

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. Based on hedges currently in place, we have hedged 13,000 barrels of daily crude oil production, or approximately 79% of the midpoint of guidance for the fourth quarter of 2014, at a weighted average floor/swap price of $92.92 per barrel. For 2015, we have hedged 11,992 barrels of daily crude oil production at a weighted average floor/swap price of $90.20 per barrel. For 2016, we have hedged 3,000 barrels of daily crude oil production at a weighted average floor/swap price of $90.84 per barrel.

We have also hedged 5,000 MMBtu (million British Thermal Units) of daily natural gas production, or approximately 13% of the midpoint of guidance for the fourth quarter of 2014, at a weighted average floor/swap price of $4.50 per MMBtu. For the first quarter of 2015, we have hedged 5,000 MMBtu of daily natural gas production at a weighted average floor/swap price of $4.50 per MMBtu.

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

Eagle Ford Shale Operational Update

Third Quarter 2014 Update

Third quarter production from our Eagle Ford operations was 16,929 BOEPD, up 8% compared to 15,618 BOEPD in the second quarter. Approximately 76% of our third quarter production was from crude oil, 13% was from NGLs and 11% was from natural gas. In September 2014, our average production was 17,936 BOEPD, 75% of which was from crude oil, 13% was from NGLs and 12% was from natural gas. Year-to-date, we have turned in line 55 (32.9 net) operated wells (excludes six shallow and five non-operated wells).

Below are the results and statistics for Eagle Ford wells (excluding shallow and non-operated wells) over the past six quarters: [1]

	Averages				Peak Gross Daily Production Rates[2]			30-Day Average Gross Daily Production Rates[2]		
	Gross/ Net Wells	Lateral Length *Feet*	Frac Stages	Proppant *lbs.*	Oil Rate *BOPD*	Equivalent Rate *BOEPD*	Oil Percentage	Oil Rate *BOPD*	Equivalent Rate *BOEPD*	Oil Percentage
Time Period										
2013 - 2nd quarter	14 / 8.6	5,588	23.0	5,184,664	1,181	1,397	85%	691	845	82%
2013 - 3rd quarter	10 / 5.6	5,901	23.8	6,526,680	1,375	1,596	86%	879	1,036	85%
2013 - 4th quarter	15 / 7.3	5,730	24.1	7,789,759	1,418	1,624	87%	960	1,119	86%
2014 - 1st quarter	14 / 10.2	5,836	25.2	7,791,564	1,159	1,457	80%	695	844	82%
2014 - 2nd quarter	24 / 14.4	5,462	25.1	9,179,233	1,174	1,469	80%	726	896	81%
2014 – 3rd quarter[3]	17 / 8.3	6,017	27.3	10,311,303	1,132	1,350	84%	787	867	92%
Totals and averages	94 / 54.4	5,726	24.9	8,078,448	1,226	1,473	83%	780	934	83%
Operating Area										
Upper Eagle Ford[4]	2 / 1.9	5,917	26.5	9,970,830	917	1,763	52%	830	1,502	55%
Shiner ---- "Beer Six Pack"[3]	27 / 12.7	6,036	26.4	9,478,535	1,344	1,641	82%	984	1,184	83%
Rock Creek / Bozka[3]	10 / 4.6	5,952	26.4	9,230,353	1,449	1,649	88%	935	1,055	89%
Peach Creek	29 / 13.6	5,982	25.8	7,800,856	1,295	1,426	91%	816	899	91%
Shiner - Mod. GOR	12 / 9.2	5,124	21.7	6,579,536	1,118	1,346	83%	628	763	82%
Shiner - High GOR	14 / 12.5	4,928	21.6	6,144,944	833	1,189	70%	500	706	70%
Totals and averages	94 / 54.4	5,726	24.9	8,078,448	1,226	1,473	83%	780	934	83%

(1) Excludes non-operated wells and "shallow" wells, defined as wells whose vertical depth, including the "curve," is 10,500 feet or less.

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

(3) 30-day information for the Kosmo #2H ---- #5H wells, the Porter #3H ---- #7H and #9H, or the L&J Lee #1H ---- #2H wells (12 wells in total) is not yet available.

(4) Does not include the Fojtik #1H (Upper Eagle Ford well brought on line in March 2013).

During the third quarter of 2014, we turned in line 17 (8.3 net) operated wells (excludes four shallow wells and one non-operated well). As a group, these 17 wells had an average IP rate of 1,350 BOEPD over an average of 27.3 frac stages, with 84% of production from crude oil. Of these 17 wells, five wells with sufficient production history had a 30-day average rate of 867 BOEPD, with 92% of production from crude oil.

Among these wells, the more notable wells and their IP rates included the Cinco J Ranch #1H (2,611 BOEPD with 32 frac stages), the L&J Lee #2H (2,166 BOEPD with 25 frac stages), the L&J Lee #1H (2,102 BOEPD with 25 frac stages), the Porter #6H (2,019 BOEPD with 27 frac stages) and the Porter #7H (1,944 BOEPD with 24 frac stages). The average amount of proppant per stage for these 17 wells was approximately 368,000 pounds, flat with the second quarter of 2014.

Upper Eagle Ford (Marl) Shale Update

Thus far in the second half of 2014, we have completed six Upper Eagle Ford wells, all of which are now flowing back and being tested. Two of those wells (the Netardus #2H and Netardus #3H) have been flowing into sales for approximately 25 days. In addition to the Netardus wells, the Welhausen #7H and Welhausen #8H wells have recently been turned in line and are cleaning up, while the Hinze #2H and Hinze #3H wells were just completed and are in the early stages of clean-up. To date during 2014, we have completed eight Upper Eagle Ford wells and for the remainder of 2014 we expect ten additional Upper Eagle Ford wells to be drilled, completed and turned in line.

The Welhausen #A2H was turned in line in March 2014 and has cumulative production of 179,394 BOE (52% oil), or an average of 1,008 BOEPD over 178 producing days, along with a 60-day rate of 1,519 BOEPD, a 30-day rate of 1,767 BOEPD and a peak rate of 2,238 BOEPD.

The Martinsen #2H was turned in line in May 2014 and has cumulative production of 178,584 BOE (54% oil), or an average of 1,038 BOEPD over 172 producing days, along with a 60-day rate of 1,149 BOEPD, a 30-day rate of 1,238 BOEPD and a peak rate of 1,599 BOEPD.

After observing the performance of these wells relative to adjacent wells in the Lower Eagle Ford and the fact that their initial decline rates are less than what we have typically seen with the Lower Eagle Ford, we are increasingly confident that the Upper Eagle Ford and Lower Eagle Ford are separate reservoirs, but additional completion and production information from additional wells will be necessary to confirm that belief. During the fourth quarter of 2014 and into 2015, we will continue to test the Upper Eagle Ford across our Lavaca County acreage.

Updated Full-Year 2014 Guidance

2014 capital expenditures are expected to range between $754 and $800 million ($197 to $243 million for the fourth quarter of 2014), which is an increase of $22 to $28 million from previous guidance. This reflects increases in drilling and completion capital expenditures of between $13 and $14 million and in lease acquisition capital expenditures of between $10 and $11 million. The increase in drilling and completion expenditures is attributable to higher tubular steel, sand, trucking and completion costs. We expect to turn in line 33 (23.0 net) wells (excludes three non-operated wells) during the fourth quarter of 2014, for an estimated total of 88 (55.9 net) operated wells (excludes six shallow and eight non-operated wells) to be turned in line during 2014. For 2014, we expect to turn in line 18 (16.4 net) Upper Eagle Ford wells.

2014 production is expected to range between approximately 8.4 and 8.6 MMBOE (2.4 to 2.6 MMBOE in the fourth quarter of 2014). This represents an increase of 169 MBOE from the lower end of previous fourth quarter guidance and a decrease of 12 MBOE from the upper end of previous fourth quarter guidance.

2014 Adjusted EBITDAX, which includes the cash impact of derivatives, is expected to range between $387 and $427 million ($100 to $140 million during the fourth quarter of 2014). This represents a decrease of $7 to $12 million from previous guidance. Our estimates assume the benchmark (WTI) oil price will average $80.67 per barrel and the benchmark (Henry Hub) natural gas price will average $3.97 per MMBTU in the fourth quarter of 2014.

Please see the Guidance Table included in this release for guidance estimates for full-year 2014. These estimates are meant to provide guidance only and are subject to revision as our operating environment changes.

Third Quarter 2014 Conference Call

A conference call and webcast, during which management will discuss third quarter 2014 financial and operational results, is scheduled for Thursday, October 30, 2014 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 3713192), or via webcast 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 3713192. 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 Corp. (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 their ability to meet their future obligations; compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters; 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.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited

(in thousands, except per share data)

	Three months ended		Three months ended	Nine months ended	
	September 30,		June 30,	September 30,	
	2014	2013	2014	2014	2013
Revenues					
Crude oil	$ 118,716	$ 100,564	$ 112,090	$ 336,382	$ 250,48
Natural gas liquids (NGLs)	9,790	8,212	8,037	27,200	22,652
Natural gas	13,354	12,872	16,302	47,859	40,465
Total product revenues	141,860	121,648	136,429	411,441	313,606
(Loss) gain on sales of property and equipment, net	63,520	(186)	(51)	120,295	(479)
Other	16	151	2,983	2,886	1,339
Total revenues	205,396	121,613	139,361	534,622	314,466
Operating expenses					
Lease operating	15,296	8,457	12,403	38,103	24,891
Gathering, processing and transportation	4,893	3,039	3,526	11,380	9,598
Production and ad valorem taxes	7,690	6,597	7,510	22,505	19,532
General and administrative (excluding equity-classified share-based compensation) (a)	10,540	11,667	14,014	40,417	34,495
Total direct operating expenses	38,419	29,760	37,453	112,405	88,516
Share-based compensation - equity classified awards (b)	987	1,010	826	2,638	4,781
Exploration	1,986	3,957	3,373	13,995	18,097
Depreciation, depletion and amortization	71,999	62,450	71,437	215,623	178,355
Impairments	6,084	132,224	117,908	123,992	132,224
Total operating expenses	119,475	229,401	230,997	468,653	421,973

Operating income (loss)	85,921	(107,788)	(91,636)	65,969	(107,507
Other income (expense)					
Interest expense	(21,953)	(20,218)	(23,229)	(67,716)	(56,505)
Loss on extinguishment of debt	--	--	--	--	(29,157)
Derivatives	66,457	(24,035)	(42,665)	8,130	(23,208)
Other	1,349	35	30	1,380	79
Income (loss) before income taxes	131,774	(152,006)	(157,500)	7,763	(216,298
Income tax (expense) benefit	(42,113)	53,106	56,716	339	75,577
Net income (loss)	89,661	(98,900)	(100,784)	8,102	(140,721
Preferred stock dividends	(7,641)	(1,725)	(1,718)	(11,081)	(5,175)
Induced conversion of preferred stock	(888)	--	(3,368)	(4,256)	--
Net income (loss) attributable to common shareholders	$ 81,132	$ (100,625)	$ (105,870)	$ (7,235)	$ (145,8
Net income (loss) per share:					
Basic	$ 1.13	$ (1.54)	$ (1.59)	$ (0.11)	$ (2.38)
Diluted	$ 0.87	$ (1.54)	$ (1.59)	$ (0.11)	$ (2.38)
Weighted average shares outstanding, basic	71,536	65,465	66,514	67,909	61,272
Weighted average shares outstanding, diluted	103,606	65,465	66,514	67,909	61,272

	Three months ended		Three months ended	Nine months ended	
	September 30,		June 30,	September 30,	
	2014	2013	2014	2014	2013
Production					
Crude oil (MBbls)	1,247	954	1,119	3,442	2,411
NGLs (MBbls)	308	254	261	796	748
Natural gas (MMcf)	3,201	3,591	3,618	10,412	10,933
Total crude oil, NGL and natural gas production (MBOE)	2,089	1,807	1,983	5,973	4,982
Prices					
Crude oil ($ per Bbl)	$ 95.19	$ 105.37	$ 100.16	$ 97.72	$ 103.87
NGLs ($ per Bbl)	$ 31.76	$ 32.34	$ 30.85	$ 34.18	$ 30.27
Natural gas ($ per Mcf)	$ 4.17	$ 3.58	$ 4.51	$ 4.60	$ 3.70
Prices - Adjusted for derivative settlements					
Crude oil ($ per Bbl)	$ 89.08	$ 100.50	$ 94.72	$ 93.08	$ 104.13
NGLs ($ per Bbl)	$ 31.76	$ 32.34	$ 30.85	$ 34.18	$ 30.27
Natural gas ($ per Mcf)	$ 4.19	$ 3.71	$ 4.20	$ 4.42	$ 3.79

(a) Includes liability-classified share-based compensation expense attributable to our performance-based restricted stock units which are payable in cash upo the achievement of certain market-based performance metrics. A total of $(0.4) million, $1.1 million, $6.6 million and $1.5 million attributable to these awards included in the three and nine months ended September 30, 2014 and 2013, respectively.

(b) 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	
	September 30,	December 31,
	2014	2013
Assets		

Current assets	$ 339,044	$ 233,696
Net property and equipment	2,342,903	2,237,304
Other assets	40,432	36,087
Total assets	$ 2,722,379	$ 2,507,087
Liabilities and shareholders' equity		
Current liabilities	$ 277,638	$ 258,145
Revolving credit facility	--	206,000
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	775,000
Other liabilities and deferred income taxes	271,074	179,138
Total shareholders' equity	1,098,667	788,804
Total liabilities and shareholders' equity	$ 2,722,379	$ 2,507,087

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited

(in thousands)

	Three months ended September 30,		Three months ended June 30,	Nine months ended September 30,	
	2014	2013	2014	2014	2013
Cash flows from operating activities					
Net income (loss)	$ 89,661	$ (98,900)	$ (100,784)	$ 8,102	$ (140,721)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Loss on extinguishment of debt	--	--	--	--	29,157
Depreciation, depletion and amortization	71,999	62,450	71,437	215,623	178,355
Impairments	6,084	132,224	117,908	123,992	132,224
Accretion of firm transportation obligation	407	407	230	991	1,263
Derivative contracts:					
Net losses (gains)	(66,457)	24,035	42,665	(8,130)	23,208
Cash settlements, net	(7,557)	(4,165)	(7,222)	(17,836)	1,625
Deferred income tax expense (benefit)	42,113	(53,106)	(56,516)	(339)	(75,577)
(Gain) loss on sales of assets, net	(63,520)	186	51	(120,295)	479
Non-cash exploration expense	1,808	3,759	3,285	8,387	14,167
Non-cash interest expense	1,063	961	1,039	3,114	2,846
Share-based compensation (equity-classified)	987	1,010	826	2,638	4,781
Other, net	44	116	75	325	198
Changes in operating assets and liabilities	24,625	26,106	(40,361)	(16,122)	52,829
Net cash provided by operating activities	101,257	95,083	32,633	200,450	224,834
Cash flows from investing activities					
Acquisition, net	--	--	--	--	(358,239)
Receipts (payments) to settle obligations assumed in acquisition, net	33,712	(6,713)	--	33,712	(43,023)
Capital expenditures - property and equipment	(194,451)	(127,645)	(190,776)	(545,031)	(356,964)
Proceeds from sales of assets, net	215,281	(214)	668	311,913	653
Net cash used in investing activities	54,542	(134,572)	(190,108)	(199,406)	(757,573)
Cash flows from financing activities					
Proceeds from the issuance of preferred stock, net	(316)	--	313,646	313,330	--
Payments made to induce conversion of preferred stock	(888)	--	(3,368)	(4,256)	--
Proceeds from the issuance of senior notes	--	--	--	--	775,000
Retirement of senior notes	--	--	--	--	(319,090)
Proceeds from revolving credit facility borrowings	75,000	66,000	217,000	377,000	219,000
Repayment of revolving credit facility borrowings	(130,000)	(5,000)	(352,000)	(583,000)	(91,000)
Debt issuance costs paid	--	(501)	(151)	(151)	(25,199)

Dividends paid on preferred and common stock	(1,329)	(1,725)	(2,111)	(5,165)	(5,137)
Other, net	329	(54)	--	1,414	(164)
Net cash provided by (used in) financing activities	(57,204)	58,720	173,016	99,172	553,410
Net increase (decrease) in cash and cash equivalents	98,595	19,231	15,541	100,216	20,671
Cash and cash equivalents - beginning of period	25,095	19,090	9,554	23,474	17,650
Cash and cash equivalents - end of period	$ 123,690	$ 38,321	$ 25,095	$ 123,690	$ 38,321
Supplemental disclosures of cash paid for:					
Interest	$ 744	$ 1,036	$ 46,009	$ 47,778	$ 24,251
Income taxes (net of refunds received)	$ --	$ --	$ 100	$ 100	$ --

PENN VIRGINIA CORPORATION

CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited

(in thousands)

	Three months ended		Thre
	September 30,		June
	2014	2013	2014
Reconciliation of GAAP "Net income (loss) " to Non-GAAP "Net income (loss) applicable to common shareholders, as adjusted"			
Net income (loss)	$ 89,661	$ (98,900)	$ (10
Adjustments for derivatives:			
Net losses (gains)	(66,457)	24,035	42,6
Cash settlements, net	(7,557)	(4,165)	(7,22
Adjustment for acquisition transaction expenses	--	--	--
Adjustment for impairments	6,084	132,224	117,
Adjustment for restructuring costs	18	--	(3)
Adjustment for (gain) loss on sale of assets, net	(63,520)	186	51
Adjustment for loss on extinguishment of debt	--	--	--
Impact of adjustments on income taxes	42,004	(53,202)	(55,2
Preferred stock dividends	(7,641)	(1,725)	(1,71
Net income (loss) applicable to common shareholders, as adjusted (a)	$ (7,408)	$ (1,547)	$ (4,
Net income (loss) applicable to common shareholders, as adjusted, per share, diluted	$ (0.10)	$ (0.02)	$ (0.
Reconciliation of GAAP "Net income (loss)" to Non-GAAP "Adjusted EBITDAX"			
Net income (loss)	$ 89,661	$ (98,900)	$ (10
Income tax expense (benefit)	42,113	(53,106)	(56,7
Interest expense	21,953	20,218	23,2
Depreciation, depletion and amortization	71,999	62,450	71,4
Exploration	1,986	3,957	3,37
Share-based compensation expense (equity-classified awards)	987	1,010	826
EBITDAX	228,699	(64,371)	(58,6
Adjustments for derivatives:			
Net losses (gains)	(66,457)	24,035	42,6
Cash settlements, net	(7,557)	(4,165)	(7,22
Adjustment for acquisition transaction expenses	--	2,396	--
Adjustment for impairments	6,084	132,224	117,
Adjustment for (gain) loss on sale of assets, net	(63,520)	186	51
Adjustment for other non-cash items	407	647	230
Adjustment for loss on extinguishment of debt	--	--	--
Adjusted EBITDAX (b)	97,656	90,952	94,9
Pro forma EBITDAX from our 2013 Eagle Ford Shale acquisition	--	3,607	--

Pro forma Adjusted EBITDAX	$ 97,656	$ 94,559	$ 94

(a) Net income (loss) applicable to common shareholders, as adjusted, represents net income (loss), less preferred stock dividends, adjusted to exclude the e
changes in the fair value of derivatives, acquisition transaction expenses, impairments, restructuring costs, net gains and losses on the sale of assets and los
this presentation is commonly used by investors and professional research analysts in the valuation, comparison, rating and investment recommendations of
exploration and production industry. We use this information for comparative purposes within our industry. Net income (loss) applicable to common sharehold
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, exploratio
compensation expense, further adjusted to exclude the effects of non-cash changes in the fair value of derivatives, acquisition transaction expenses, impairm
assets, loss on extinguishment of debt and other non-cash items. We believe this presentation is commonly used by investors and professional research ana
and investment recommendations of companies within the oil and gas exploration and production industry. We use this information for comparative purposes
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 forr
Adjusted EBITDAX to include the pro forma EBITDAX from our Eagle Ford Shale acquisition in April 2013 and represents EBITDAX as defined in our revolvir

PENN VIRGINIA CORPORATION

GUIDANCE TABLE - unaudited

(dollars in millions except where noted)

We are providing the following guidance regarding financial and operational expectations for full-year 2014. These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

	First Quarter 2014	Second Quarter 2014	Third Quarter 2014	Year-to-Date 2014	Fourth Quarter 2014 Guidance			Full-Year 2014 Guidance		
Production:										
Crude oil (MBbls)	1,076	1,119	1,247	3,442	1,458	--	1,558	4,900	--	5,000
NGLs (MBbls)	227	261	308	796	384	--	424	1,180	--	1,220
Natural gas (MMcf)	3,593	3,618	3,201	10,412	3,238	--	3,658	13,650	--	14,070
Equivalent production (MBOE)	1,902	1,983	2,089	5,973	2,382	--	2,592	8,355	--	8,565
Equivalent daily production (BOEPD)	21,133	21,786	22,706	21,881	25,888	--	28,170	22,891	--	23,466
Percent crude oil and NGLs	68.5%	69.6%	74.5%	70.9%	76.5%	--	77.3%	71.9%	--	73.5%
Production revenues (a):										
Crude oil	$ 105.6	112.1	118.7	336.4	116.0	--	140.0	452.4	--	476.4
NGLs	$ 9.4	8.0	9.8	27.2	11.0	--	16.0	38.2	--	43.2
Natural gas	$ 18.2	16.3	13.4	47.9	12.0	--	18.0	59.9	--	65.9
Total product revenues	$ 133.2	136.4	141.9	411.4	139.0	--	174.0	550.5	--	585.5
Total product revenues ($ per BOE)	$ 70.01	68.81	67.91	68.88	58.37	--	67.15	65.88	--	68.35
Percent crude oil and NGLs	86.3%	88.1%	90.6%	88.4%	89.7%	--	91.4%	86.4%	--	91.5%
Operating expenses:										
Lease operating ($ per BOE)	$ 5.47	6.26	7.32	6.38	5.03	--	5.93	6.00	--	6.25
Gathering, processing and transportation costs ($ per BOE)	$ 1.56	1.78	2.34	1.91	1.61	--	1.79	1.82	--	1.87
Production and ad valorem taxes (percent of oil and gas revenues)	5.5%	5.5%	5.4%	5.5%	6.0%	--	6.6%	5.6%	--	5.8%
General and administrative:										
Recurring general and administrative	$ 9.7	11.8	10.6	32.1	9.8	--	11.3	41.9	--	43.4
Non-recurring general and administrative	$ 0.2	1.1	0.3	1.7	0.0	--	0.0	1.7	--	1.7
Share-based compensation	$ 6.8	1.9	0.6	9.3	3.0	--	6.0	12.3	--	15.3
Total reported G&A	$ 16.7	14.8	11.5	43.1	12.8	--	17.3	55.8	--	60.3
Exploration:										
Total reported exploration	$ 8.6	3.4	2.0	14.0	6.0	--	9.0	20.0	--	23.0
Unproved property amortization	$ 3.3	3.4	1.8	8.5	1.5	--	2.0	10.0	--	10.5
Depreciation, depletion and amortization ($ per BOE)	$ 37.95	36.03	34.47	36.10	34.00	--	35.00	35.50	--	35.77

Adjusted EBITDAX (b)	$ 93.8	95.0	97.7	286.5	100.0	--	140.0	386.5	--	426.5
Capital expenditures:										
Drilling and completion	$ 135.5	154.0	148.7	438.2	185.0	--	205.0	623.2	--	643.2
Lease acquisitions	$ 36.1	12.8	51.0	99.9	8.0	--	25.0	107.9	--	124.9
Seismic (c)	$ 4.5	0.1	0.2	4.8	2.0	--	7.0	6.8	--	11.8
Pipeline, gathering, facilities and other	$ 6.3	2.6	5.0	13.9	2.0	--	6.0	15.9	--	19.9
Total capital expenditures	$ 182.4	169.5	204.9	556.8	197.0	--	243.0	753.7	--	799.8
End of period debt outstanding	$ 1,265.0	1,130.0	1,075.0	1,075.0	1,075.0	--	1,075.0	1,075.0	--	1,075.0
Interest expense:										
Total reported interest expense	$ 22.5	23.2	22.0	67.7	22.0	--	25.0	89.7	--	92.7
Cash interest expense	$ 21.5	22.2	20.9	64.6	21.0	--	23.5	85.6	--	88.1
Preferred stock dividends paid	$ 1.7	2.1	1.4	5.2	6.9	--	6.9	12.2	--	12.2
Effective tax rate	42.6%	36.0%	32.0%	4.4%	35.0%	--	36.0%			

(a) Assumes average benchmark prices of $80.67 per barrel for crude oil and $3.97 per MMBtu for natural gas in the fourth quarter of 2014, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments. NGL realized pricing is assumed to be $35.00 per barrel in the fourth quarter of 2014.

(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	Ceiling
Natural gas:		(MMBtu)	($ / MMBtu)	
Fourth quarter 2014	Swaps	5,000	4.50	
First quarter 2015	Swaps	5,000	4.50	
Crude oil:		(barrels)	($ / barrel)	
Fourth quarter 2014	Collars	2,000	90.00	94.33
First quarter 2015	Collars (a)	4,000	87.50	94.66
Second quarter 2015	Collars (a)	4,000	87.50	94.66
Third quarter 2015	Collars (a)	3,000	86.67	94.73
Fourth quarter 2015	Collars (a)	3,000	86.67	94.73
Fourth quarter 2014	Swaps (a)	11,000	93.45	
First quarter 2015	Swaps (a)	9,000	91.81	
Second quarter 2015	Swaps (a)	9,000	91.81	
Third quarter 2015	Swaps (a)	8,000	91.06	
Fourth quarter 2015	Swaps (a)	8,000	91.06	
First quarter 2016	Swaps	3,000	90.84	
Second quarter 2016	Swaps	3,000	90.84	
Third quarter 2016	Swaps	3,000	90.84	
Fourth quarter 2016	Swaps	3,000	90.84	
First quarter 2015	Swaption (b)	1,000	88.00	
Second quarter 2015	Swaption (b)	1,000	88.00	
Third quarter 2015	Swaption (b)	1,000	88.00	

Fourth quarter 2015	Swaption (b)	1,000	88.00

(a) All or a portion of these derivatives have include "lower" puts sold at a strike price of $70 per barrel. If the price of WTI oil goes below $70 per barrel, the cash receipts on the derivatives will be limited to the difference between the swap / floor price and $70 per barrel.

(b) This swaption contract gives our counterparties the option to enter into a fixed price swap with us at a future date. If the forward commodity price for calendar year 2015 is higher than or equal to $88.00 per barrel on December 31, 2014, the counterparty will exercise its option to enter into a fixed price swap at $88.00 per barrel for calendar year 2015, at which point the contract functions as a fixed price swap. If the forward commodity price for calendar year 2015 is lower than $88.00 per barrel on December 31, 2014, the option expires and no fixed price swap is in effect.

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 2014 would increase or decrease by approximately $12.9 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 of 2014 would increase or decrease by approximately $2.9 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.

Contact

James W. Dean
Vice President, Corporate Development
Ph: (610) 687-7531 Fax: (610) 687-3688
E-Mail: invest@pennvirginia.com