Penn Virginia Corporation Announces Record Quarterly Oil Production and Preliminary 2014 Oil Production Growth Guidance of 65 to 85 Percent

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Core Eagle Ford Shale Position Expanded to 67,000 Net Acres

Drilling Inventory Increased to Approximately 890 Locations

Mid-Year 2013 Eagle Ford Shale Proved Reserves of 51 MMBOE and 3P Reserves of 170 MMBOE

Continued Excellent Drilling Results in the Eagle Ford Shale

Borrowing Base Increased From $350 Million to $425 Million

Financial Liquidity of Approximately $330 Million

RADNOR, Pa., Oct. 30, 2013 (GLOBE NEWSWIRE) -- Penn Virginia Corp. (NYSE:PVA) today reported financial results for the three months ended September 30, 2013, provided updates of its operations and 2013 guidance, and provided preliminary 2014 guidance.

Third Quarter 2013 Highlights

Third quarter 2013 financial results, as compared to second quarter 2013 results, were as follows:

- Product revenues from the sale of oil, natural gas liquids (NGLs) and natural gas were $121.6 million, or $67.33 per barrel of oil equivalent (BOE), an increase of 11 percent compared to $109.7 million, or $62.78 per BOE.
- Oil and NGL revenues were $108.8 million, or 89 percent of product revenues, an increase of 15 percent compared to $94.2 million, or 86 percent of product revenues.
- Operating margin, a non-GAAP (generally accepted accounting principles) measure, was $50.86 per BOE, an increase of 10 percent compared to $46.09 per BOE.
- Operating income, excluding $132.2 million of impairment expense, was $24.4 million, an increase of 336 percent compared to operating income of $5.6 million, excluding $2.4 million of acquisition transaction expenses.
- Adjusted EBITDAX, a non-GAAP measure, was $88.3 million, an increase of six percent compared to $83.1 million.
- Net loss attributable to common shareholders (which includes our preferred stock dividend) was $100.6 million, or $1.54 per diluted share, compared to a loss of $27.2 million, or $0.43 per diluted share.
- Adjusted net loss attributable to common shareholders, a non-GAAP measure which includes our preferred stock dividend but excludes the effects of impairments and other costs and other gains or losses that affect comparability to other periods, was $1.5 million, or $0.02 per diluted share, compared to a loss of $10.9 million, or $0.17 per diluted share.
- In October 2013, the borrowing base under our revolving credit facility was increased from $350 million to $425 million. Pro forma financial liquidity at September 30, 2013 was approximately $330 million, compared to approximately $300 million of financial liquidity at June 30, 2013.

Recent operational highlights were as follows:

- Third quarter production was 1.8 million BOE (MMBOE), or 19,638 BOE per day (BOEPD), up two percent compared to 1.7 MMBOE, or 19,209 BOEPD, in the second quarter.
  - Third quarter Eagle Ford Shale production was 12,489 BOEPD, up nine percent compared to 11,476 BOEPD in the second quarter.
  - Record quarterly oil production of 10,373 barrels of oil per day (BOPD), an increase of 10 percent over 9,430 BOPD in the second quarter.
  - Despite this growth, our production was less than expected during the third quarter, due primarily to less than anticipated outside operated Eagle Ford Shale production.
- Proved oil and gas reserves in the Eagle Ford Shale increased 34 percent to approximately 51 MMBOE at mid-year 2013 from approximately 38 MMBOE at year-end 2012, pro forma to include approximately 12 MMBOE acquired in the second quarter of 2013.
  - Eagle Ford Shale proved, probable and possible (3P) reserves were approximately 170 MMBOE.
- The pre-tax present value of estimated future net cash flows from Eagle Ford Shale proved reserves, discounted at 10 percent (PV-10) and assuming an oil price of $91.60 per barrel and a natural gas price of $3.44 per MMBtu (million British thermal units), was $1,032 million.
- In the Eagle Ford Shale, we have a total of 158 (105.4 net) producing wells, 10 (4.8 net) operated wells completing or waiting on completion and six (3.2 net) operated wells being drilled.
  - The average peak gross production rate per well for the 18 most recent operated wells, excluding one well that had a shortened lateral length due to drilling issues, was 1,288 BOEPD. The initial 30-day average gross production rate for the 15 of these 18 wells with a 30‑day production history was 874 BOEPD. The average lateral length for these 18 operated wells was 5,920 feet, with an average of 24.2 fracturing (frac) stages.
- The average stimulation (completion) cost per frac stage was approximately $110,000 in the third quarter of 2013, compared to approximately $150,000 in the second quarter of 2013. The average total well cost per frac stage was approximately $350,000 in the third quarter of 2013, compared to approximately $430,000 in the second quarter of 2013. This decrease was due primarily to the reduced stimulation costs, as well as efficiency gains from increased use of pad drilling.
- Currently, we have a total of approximately 107,000 gross (67,000 net) acres in the Eagle Ford Shale.
  - Over 5,000 net acres in the Eagle Ford Shale have been added since early August at a cost of approximately $1,600 per acre.
  - We expect to add approximately 7,000 additional net Eagle Ford Shale acres in the fourth quarter of 2013 and, therefore, we increased our estimated 2013 lease acquisition capital expenditures by $11 million.

- We estimate that we currently have approximately 890 undeveloped drilling locations, which is a drilling inventory of approximately 10 years, assuming our ongoing drilling program.
  - This inventory increased from approximately 750 locations reported previously.
  - 16 of our recently drilled wells were drilled off of six multi-well pads, with an average effective nominal spacing of approximately 70 acres.

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, our operating cash flows and margins remained strong as a result of the continued growth in oil production, as well as lower unit operating costs. Despite this growth, our production and revenues increased less than expected during the third quarter due to several issues associated with the outside operated Eagle Ford Shale program. Our non-operated partner recently reduced its rig count from two to one and, as a result, we have increased our operated drilling rig count by one rig. We continue to expect our 2013 results to remain within our previous guidance. The increase in operated activity during the fourth quarter will have a negligible production and cash flow effect in 2013 but will, of course, provide much more of a benefit in 2014. We now expect 2014 oil production growth of between 65 and 85 percent over 2013 with the assumption that five operated rigs and one outside operated rig will be dedicated to the Eagle Ford Shale drilling program.

"Additional leasing in the Eagle Ford Shale at a cost of approximately $1,600 per net acre has further increased our net acreage and we continue to have success in finding additional opportunities to grow our position. Therefore, our stated 100,000 net acre goal remains intact and achievable at attractive costs. As a result of and in conjunction with successful downspaced drilling, we have increased our estimated drilling inventory by about 20 percent to our current estimate of approximately 890 locations.

"During the third quarter, our well costs decreased and well productivity increased as a result of lower completion costs, the increased use of multi-well pads and the use of "zipper fracs," which have contributed to greater productivity per well and per frac stage. We continue to consider additional techniques to further optimize our well results and value.

"Our balance sheet remains sound with approximately $330 million of financial liquidity. We recently had our borrowing base increased from $350 to $425 million as the value-added drilling in the Eagle Ford Shale has beneficially impacted our reserve value. We expect to fund our capital programs over the next few years with increasing operating cash flows, net proceeds from asset sales and borrowings under our revolver, with the goals of decreasing our leverage ratio and increasing our liquidity over this same timeframe."

Third Quarter 2013 Results

Overview of Financial Results

The $24.4 million of operating income in the third quarter, excluding $132.2 million of impairment expense, was an $18.8 million improvement over $5.6 million in the second quarter, excluding $2.4 million of acquisition transaction expenses. This improvement was due primarily to an $11.9 million increase in total product revenues, a $3.9 million decrease in exploration expense, a $1.9 million decrease in depreciation, depletion and amortization (DD&A) expense and a $1.7 million decrease in share-based compensation expense. The effect of these changes was partially offset by a $0.6 million increase in total direct operating expenses, excluding acquisition transaction expenses.

Product Revenues

Total product revenues were $121.6 million in the third quarter, an 11 percent increase compared to $109.7 million in the second quarter, due primarily to a seven percent increase in average product pricing to $67.33 per BOE from $62.78 per BOE, as well as a three percent increase in equivalent production. Oil and NGL revenues were $108.8 million in the third quarter, a 15 percent increase compared to $94.2 million in the second quarter, due to an eight percent increase in production and seven percent increase in oil and NGL prices. Oil and NGL revenues were 89 percent of product revenues in the third quarter, compared to 86 percent in the second quarter.

Operating Expenses

As discussed below, third quarter total direct operating expenses increased $0.6 million to $29.8 million, or $16.47 per BOE produced, compared to $29.2 million, excluding $2.4 million of acquisition transaction expenses, or $16.68 per BOE, in the second quarter.

- Lease operating expenses decreased by $0.1 million to $8.5 million, or $4.68 per BOE, from $8.6 million, or $4.94 per BOE, due to higher production contributions from the low-cost Eagle Ford Shale.
- Gathering, processing and transportation expenses were unchanged at $3.0 million, or $1.68 per BOE, compared to $3.0 million, or $1.70 per BOE.
- Production and ad valorem taxes decreased by $0.4 million to $6.6 million, or 5.4 percent of product revenues, from $7.0 million, or 6.4 percent of product revenues, due primarily to the receipt of severance tax refunds from the State of Texas for prior periods.
- General and administrative expenses, excluding share-based and liability-based compensation expenses of $2.1 million, increased by $0.4 million to $10.6 million, or $5.85 per BOE, from $10.2 million, or $5.81 per BOE, excluding share-based and liability-based compensation and acquisition transaction expenses of $5.5 million.

Exploration expense decreased to approximately $4.0 million in the third quarter from $7.8 million in the second quarter. The decrease was due primarily to reduced amortization on unproved properties in the Eagle Ford Shale.

DD&A expense decreased by $1.9 million to $62.5 million, or $34.57 per BOE, in the third quarter of 2013 from $64.3 million, or $36.80 per BOE, in the second quarter due primarily to the increase in mid-year 2013 Eagle Ford Shale reserves.

In the third quarter of 2013, we recognized $132.2 million of impairment expense, including the Granite Wash in the Mid-Continent region ($121.8 million), the Marcellus Shale in Pennsylvania ($9.5 million) and the Selma Chalk in Mississippi ($0.9 million), in each case due primarily to market declines in commodity prices.

Production

Production in the third quarter was 1.8 MMBOE, or 19,638 BOEPD, compared to 1.7 MMBOE, or 19,209 BOEPD, in the second quarter. As a percentage of total equivalent production, oil and NGL volumes were 67 percent in the third quarter of 2013, compared to 64 percent in the second quarter. As discussed further below in the release, we now expect outside operated production volumes for the second half of 2013 to be approximately 0.2 MMBOE less than previous expectations, causing essentially all of the variance from the midpoint of our previous production guidance. We recently added an operated rig in an attempt to mitigate the shortfall and increase fourth quarter 2013 production, as well as to benefit 2014 production.

The table below shows quarterly production detail.

	Total and Daily Equivalent Production for the Three Months Ended					
Region / Play Type	Sept. 30, 2013	June 30, 2013	Sept. 30, 2012	Sept. 30, 2013	June 30, 2013	Sept. 30, 2012
	(in MBOE)			(in BOEPD)		
Texas	1,395	1,300	901	15,164	14,331	9,792

Eagle Ford Shale	*1,149*	*1,044*	*581*	*12,489*	*11,476*	*6,317*
Cotton Valley	*180*	*184*	*216*	*1,956*	*2,025*	*2,345*
Haynesville Shale	*66*	*71*	*104*	*718*	*780*	*1,130*
Mid-Continent	219	243	289	2,385	2,671	3,136
Mississippi	179	195	208	1,951	2,139	2,256
Other[(1)]	13	11	107	138	118	1,165
Totals	1,807	1,748	1,504	19,638	19,209	16,348
Pro Forma Totals[(2)]	1,807	1,748	1,388	19,638	19,209	15,089

[(1)] Other includes Marcellus Shale and Pearsall Shale production.

[(2)] Pro forma to exclude production from the Appalachian assets sold in July 2012.

Notes - Numbers may not add due to rounding.

Capital Expenditures

During the third quarter, capital expenditures were approximately $120 million, a decrease of 18 percent compared to $145 million in the second quarter, consisting of:

- $112 million for drilling and completion activities; and
- $8 million for leasehold acquisitions and other.

The approximate $25 million decrease in capital expenditures from the second quarter to the third quarter was attributable to lower lease acquisition, lower drilling and completion costs, and decreased spending on production facilities.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of September 30, 2013, we had total debt of $1,203 million, consisting of $300 million principal amount of 7.25 percent senior unsecured notes due 2019, $775 million of 8.50 percent senior unsecured notes due 2020 and $128 million outstanding under our revolving credit facility (Revolver). Our leverage ratio under the Revolver was 3.6 times trailing twelve months' pro forma Adjusted EBITDAX of approximately $340 million.

In October, the borrowing base under the Revolver was increased from $350 million to $425 million, with PVA electing to receive commitments for $400 million. As a result, together with cash and cash equivalents of $38 million, our pro forma liquidity, including the uncommitted amount, increased to approximately $330 million at September 30, 2013. The next borrowing base redetermination is scheduled for the spring of 2014.

During the third quarter, interest expense was $20.2 million, of which $19.3 million was cash interest expense, compared to $21.8 million in the second quarter.

During the third quarter, derivatives loss was $24.0 million, compared to a derivatives income of $8.6 million in the second quarter. Third quarter 2013 cash settlements of derivatives resulted in net cash outlays of $4.2 million, compared to $2.2 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 pre-determined prices or price ranges. Based on hedges currently in place, we have hedged approximately 9,400 barrels of daily crude oil production in the fourth quarter of 2013, or approximately 79 percent of the midpoint of guidance for fourth quarter crude oil production, at a weighted average floor/swap price of $94.69 per barrel. For 2014, we have hedged approximately 8,500 barrels of daily crude oil production, or approximately 50 percent of the midpoint of preliminary guidance, at a weighted average floor/swap price of $93.49 per barrel.

We have also hedged approximately 25,000 MMBtu of daily natural gas production in the fourth quarter of

2013, or approximately 69 percent of the midpoint of guidance for fourth quarter natural gas production, at a weighted average floor/swap price of $3.82 per MMBtu. For 2014, we have hedged approximately 12,500 MMBtu of daily natural gas production, or approximately 33 percent of the midpoint of preliminary guidance, at a weighted average floor/swap price of $4.17 per MMBtu.

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

Eagle Ford Shale Operational Update

Net production from the Eagle Ford Shale was 12,489 BOEPD in the third quarter, an increase of nine percent from 11,476 BOEPD in the second quarter. During the third quarter, we completed 16 (9.7 net) operated wells and participated in the completion of one (0.4 net) outside operated well. In the Eagle Ford Shale, we have a total of 158 (105.4 net) producing wells, 10 (4.8 net) operated wells completing or waiting on completion and six (3.2 net) operated wells being drilled. During the third quarter, only one outside operated well was turned in line and the non-operated rig count decreased from two rigs to one rig. As a result, we have responded by increasing our operated rig count by one rig and, as discussed in the preliminary 2014 guidance section below, we now expect to have five operated rigs and one non-operated rig drilling during 2014.

In the fourth quarter, we also expect to further test the upper Eagle Ford Shale with a two-well pad, one well of which will be drilled in the lower Eagle Ford Shale and one well of which will be drilled in the upper Eagle Ford Shale. This test will help determine whether the upper Eagle Ford Shale is a separate reservoir from the lower Eagle Ford Shale, which is the interval in which we typically complete our wells.

Set forth below are the results and statistics for recent Eagle Ford Shale wells:

			Peak Gross Daily Production Rates[3]			30-Day Average Gross Daily Production Rates[3]		
Well Name	Lateral Length	Frac Stages	Oil Rate	Equivalent Rate	Equivalent Rate per Frac Stage	Oil Rate	Equivalent Rate	Equivalent Rate per Frac Stage
	Feet		*BOPD*	*BOEPD*	*BOEPD/stage*	*BOPD*	*BOEPD*	*BOEPD/stage*
Operated wells								
Vana #3H	5,138	21	1,039	1,212	57.7	562	678	32.3
Vana #4H	4,852	19	888	1,038	54.6	493	592	31.2
Moose Hunter #2H	4,326	18	1,379	1,528	84.9	793	881	48.9
Moose Hunter #4H	5,836	24	1,506	1,694	70.6	966	1,090	45.4
Joseph Simper #1H	4,281	18	655	934	51.9	441	658	36.5
Effenberger-Schacherl #4H	5,470	27	1,696	1,923	71.2	914	1,127	41.7
Stag Hunter #1H	7,796	31	1,801	2,042	65.9	1,331	1,509	48.7
Stag Hunter #2H	7,930	33	1,879	2,155	65.3	1,352	1,539	46.6
Platypus Hunter #1H	6,811	24	1,651	1,903	79.3	1,245	1,425	59.4
Schacherl-Vana #1H	5,573	23	1,260	1,530	66.5	697	864	37.5
Gonzo Hunter #2H	4,570	19	569	606	31.9	419	460	24.2
Gonzo Hunter #3H	5,260	22	608	665	30.2	490	533	24.2
Gonzo Hunter #4H	4,738	20	529	576	28.8	419	455	22.8
Cannonade Ranch S. #17H	5,306	22	1,131	1,213	55.1	687	752	34.2
Cannonade Ranch S. #19H	5,475	23	768	834	36.3	495	546	23.7
Bongo Hunter #1H	6,258	26	706	772	29.7	--	--	--
Bongo North #1H	8,026	33	1,072	1,156	35	--	--	--
Bongo North #2H	7,922	33	1,315	1,414	42.9	--	--	--
Averages (18 most recent operated wells)	5,920	24.2	1,136	1,288	53.2	754	874	37.2
Averages (all 135 operated wells) [4]	4,631	19.2	986	1,107	58.6	626	719	38.7

Other wells[4]								
Cannonade Ranch S. #18H	1,630	7	394	434	62	294	335	47.8
JP Ranch #2H (Hunt)	6,778	25	309	333	13.3	281	304	12.1

[3] Wellhead rates only; the natural gas associated with these wells is yielding between 165 and 315 barrels of NGLs per million cubic feet.

[4] Includes a short-lateral operated well (Cannonade Ranch S. #18H) and a non-operated well (JP Ranch #2H).

Of our 19 most recent operated wells, 16 were drilled on six pads, with an average effective nominal spacing of approximately 70 acres. With continued leasing contiguous to our current acreage positions, along with the continued success of our pad drilling efforts and closer well spacing, we anticipate that, over time, additional wells will be added to our approximate 890 well drilling inventory.

Fourth Quarter 2013 Guidance

Updated guidance highlights that impact the fourth quarter of 2013 are as follows:

- Production is expected to be approximately 1,770 to 2,045 MBOE, or approximately 19,200 to 22,200 BOEPD.
- Product revenues, excluding the impact of any hedges, are expected to be approximately $118 to $135 million.
  - Crude oil and NGL revenues are expected to be approximately 90 percent of product revenues.
  - Settlements of current commodity hedges are expected to result in cash outlays of approximately $1 million.
- Adjusted EBITDAX, a non-GAAP measure, is expected to be approximately $89 to $100 million.
- Capital expenditures are expected to be $139 to $169 million.
  - Fourth quarter 2013 capital expenditures are expected to include $118 to $142 million for drilling and completions, $14 to $18 million for lease acquisitions and $7 to $9 million for pipeline, gathering, seismic, facilities and other.

Please see the Guidance Table included in this release for guidance estimates for fourth quarter and full-year 2013. These estimates are meant to provide guidance only and are subject to revision as our operating environment changes.

Preliminary Full-Year 2014 Guidance

As a result of the recent borrowing base increase, we expect to have approximately $250 million of available liquidity in the form of cash and cash equivalents and borrowing base availability as we enter 2014. This liquidity estimate does not include any potential net proceeds from the sale of our Eagle Ford Shale natural gas midstream and gas lift assets. We recently received bids from a number of parties for these assets which exceeded our minimum expectation. The sale of additional assets, including the right to build an Eagle Ford Shale oil gathering system, may be pursued in the first half of 2014.

As a result of the estimated year-end 2013 liquidity, together with expected 2014 cash flows and the potential net proceeds from one or more divestitures, we believe that we will have more than sufficient funds for our 2014 capital expenditures program, which we preliminarily estimate will range between $510 and $540 million, roughly equal to the revised 2013 capital expenditures guidance range of $500 to $530 million. This 2014 range assumes a drilling program utilizing a total of six drilling rigs in the Eagle Ford Shale, five of which would be operated and one of which would be outside operated. Correspondingly, full-year 2014 production is preliminarily estimated to range between approximately 9.0 and 10.0 MMBOE, or 24,600 to 27,400 BOEPD, which is 30 to 45 percent higher than the mid-point of 2013 production guidance of approximately 6.9 MMBOE, or 18,900 BOEPD. We estimate that 2014 oil and NGL production will be approximately 75 percent of total production. Full year 2014 crude oil production is expected to be between 65 and 85 percent higher than the midpoint of 2013 production guidance, while fourth quarter 2014 oil production is expected to be between 40 and 70 percent higher than the midpoint of fourth quarter 2013 oil production guidance. These early estimates are meant to provide guidance only and are subject to revision as our operating and the product pricing environments may change.

Explanation of Non-GAAP Operating Margin per BOE

Operating margin is a non-GAAP financial measure under SEC regulations which represents total product revenues less total direct operating expenses, excluding acquisition transaction expenses. Operating margin per BOE is equal to operating margin divided by total equivalent crude oil, NGL and natural gas production. Operating margin is not adjusted for the impact of hedges. We believe that operating margin per BOE is an important measure that can be used by security analysts and investors to evaluate our operating margin per unit of production and to compare it to other oil and gas companies, as well as for comparisons to other time periods.

Explanation of Non-GAAP PV-10 Value

PV-10 value is the estimated future net cash flows from estimated proved reserves discounted at an annual rate of 10 percent before giving effect to income taxes. The standardized measure is the after-tax estimated future cash flows from estimated proved reserves discounted at an annual rate of 10 percent, determined in accordance with generally accepted accounting principles (GAAP). We use PV-10 value as one measure of the value of our estimated proved reserves and to compare relative values of proved reserves among exploration and production companies without regard to income taxes. We believe that securities analysts and rating agencies use PV-10 value in similar ways. Our management believes PV-10 value is a useful measure for comparison of proved reserve values among companies because, unlike standardized measure, it excludes future income taxes that often depend principally on the characteristics of the owner of the reserves rather than on the nature, location and quality of the reserves themselves. We cannot reconcile PV-10 value to the standardized measure at this time because final income tax information for mid-year 2013 is not available.

Third Quarter 2013 Conference Call

A conference call and webcast, during which management will discuss third quarter 2013 financial and operational results, is scheduled for Thursday, October 31, 2013 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 33059048), 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 33059048. 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 primarily 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 Texas, and to a lesser extent, the Mid-Continent, Mississippi and the Marcellus Shale in Appalachia. 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; 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 independent and major oil and natural gas companies; our ability to successfully monetize select assets and repay our debt; leasehold terms expiring before production can be established; environmental 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; 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. 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.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS - unaudited

(in thousands, except per share data)

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Revenues				
Crude oil	$ 100,564	$ 56,995	$ 250,489	$ 174,100
Natural gas liquids (NGLs)	8,212	6,671	22,652	23,298
Natural gas	12,872	11,909	40,465	37,098
Total product revenues	121,648	75,575	313,606	234,496
(Loss) gain on sales of property and equipment, net	(186)	1,573	(479)	2,407
Other	151	551	1,339	2,052
Total revenues	121,613	77,699	314,466	238,955
Operating expenses				
Lease operating	8,457	6,206	24,891	24,613
Gathering, processing and transportation	3,039	3,127	9,598	11,672
Production and ad valorem taxes	6,597	4,589	19,532	7,915
General and administrative (excluding equity-classified share-based compensation) (a)	11,667	10,352	34,495	31,289
Total direct operating expenses	29,760	24,274	88,516	75,489
Share-based compensation - equity classified awards (b)	1,010	1,282	4,781	4,233
Exploration	3,957	9,265	18,097	26,647
Depreciation, depletion and amortization	62,450	49,331	178,355	151,888
Impairments	132,224	700	132,224	29,316
Loss on firm transportation commitment	--	17,332	--	17,332
Total operating expenses	229,401	102,184	421,973	304,905
Operating loss	(107,788)	(24,485)	(107,507)	(65,950)

Other income (expense)				
Interest expense	(20,218)	(14,979)	(56,505)	(44,837)
Loss on extinguishment of debt	--	(3,144)	(29,157)	(3,144)
Derivatives	(24,035)	(12,271)	(23,208)	31,250
Other	35	60	79	89
Loss before income taxes	(152,006)	(54,819)	(216,298)	(82,592)
Income tax benefit	53,106	22,208	75,577	32,444
Net loss	(98,900)	(32,611)	(140,721)	(50,148)
Preferred stock dividends	(1,725)	--	(5,175)	--
Net loss applicable to common shareholders	$ (100,625)	$ (32,611)	$ (145,896)	$ (50,148)
Net loss per share:				
Basic	$ (1.54)	$ (0.71)	$ (2.38)	$ (1.09)
Diluted	$ (1.54)	$ (0.71)	$ (2.38)	$ (1.09)
Weighted average shares outstanding, basic	65,465	46,050	61,272	46,009
Weighted average shares outstanding, diluted	65,465	46,050	61,272	46,009

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Production				
Crude oil (MBbls)	954	573	2,411	1,693
NGLs (MBbls)	254	202	748	645
Natural gas (MMcf)	3,591	4,371	10,933	16,524
Total crude oil, NGL and natural gas production (MBOE)	1,807	1,504	4,982	5,092
Prices				
Crude oil ($ per Bbl)	$ 105.37	$ 99.45	$ 103.87	$ 102.82
NGLs ($ per Bbl)	$ 32.34	$ 32.94	$ 30.27	$ 36.14
Natural gas ($ per Mcf)	$ 3.58	$ 2.72	$ 3.70	$ 2.25
Prices - Adjusted for derivative settlements				
Crude oil ($ per Bbl)	$ 100.50	$ 107.53	$ 104.13	$ 105.45
NGLs ($ per Bbl)	$ 32.34	$ 32.94	$ 30.27	$ 36.14
Natural gas ($ per Mcf)	$ 3.71	$ 3.77	$ 3.79	$ 3.36

(a) Includes liability-classified share-based compensation expense attributable to our performance-based restricted stock units that are payable in cash upon the achievement of certain market-based performance metrics. A total of $1.1 million and $0.2 million attributable to these awards is included in the three months ended September 30, 2013 and 2012 and a total of $1.5 million and $0.8 million for the nine months ended September 30, 2013 and 2012.

(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, 2013	December 31, 2012
Assets		
Current assets	$ 195,842	$ 96,515
Net property and equipment	2,170,122	1,723,359

Other assets	40,472	23,115
Total assets	$ 2,406,436	$ 1,842,989
Liabilities and shareholders' equity		
Current liabilities	238,958	112,025
Revolving credit facility	128,000	--
Senior notes due 2016	--	294,759
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	--
Other liabilities and deferred income taxes	168,695	241,089
Total shareholders' equity	795,783	895,116
Total liabilities and shareholders' equity	$ 2,406,436	$ 1,842,989

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS - unaudited

(in thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Cash flows from operating activities				
Net loss	$ (98,900)	(32,611)	(140,721)	(50,148)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Loss on extinguishment of debt	--	3,144	29,157	3,144
Loss on firm transportation commitment	--	17,332	--	17,332
Depreciation, depletion and amortization	62,450	49,331	178,355	151,888
Impairments	132,224	700	132,224	29,316
Derivative contracts:				
Net losses (gains)	24,035	12,271	23,208	(31,250)
Cash receipts (settlements)	(4,165)	9,238	1,625	24,189
Deferred income tax benefit	(53,106)	(22,208)	(75,577)	(32,444)
Loss (gain) on sales of assets, net	186	(1,573)	479	(2,407)
Non-cash exploration expense	3,759	8,310	14,167	24,765
Non-cash interest expense	961	1,057	2,846	3,107
Share-based compensation (equity-classified)	1,010	1,282	4,781	4,233
Other, net	523	99	1,461	302
Changes in operating assets and liabilities	26,106	28,117	52,829	48,187
Net cash provided by operating activities	95,083	74,489	224,834	190,214
Cash flows from investing activities				
Acquisition, net	(6,713)	--	(401,262)	--
Capital expenditures - property and equipment	(127,645)	(68,958)	(356,964)	(257,194)
Proceeds from sales of assets, net	(214)	92,749	653	93,276
Other, net	--	--	--	180
Net cash (used in) provided by investing activities	(134,572)	23,791	(757,573)	(163,738)
Cash flows from financing activities				
Proceeds from the issuance of senior notes	--	--	775,000	--
Retirement of senior notes	--	--	(319,090)	--
Proceeds from revolving credit facility borrowings	66,000	97,000	219,000	181,000
Repayment of revolving credit facility borrowings	(5,000)	(200,000)	(91,000)	(203,000)
Debt issuance costs paid	(501)	(1,779)	(25,199)	(1,779)
Dividends paid on preferred and common stock	(1,725)	--	(5,137)	(5,176)
Other, net	(54)	--	(164)	--

Net cash provided by (used in) financing activities	58,720	(104,779)	553,410	(28,955)
Net increase (decrease) in cash and cash equivalents	19,231	(6,499)	20,671	(2,479)
Cash and cash equivalents - beginning of period	19,090	11,532	17,650	7,512
Cash and cash equivalents - end of period	$ 38,321	5,033	38,321	5,033
Supplemental disclosures of cash paid for:				
Interest (net of amounts capitalized)	$ (2,544)	1,209	20,671	27,865
Income taxes (net of refunds received)	$ --	(32,263)	--	(32,574)

PENN VIRGINIA CORPORATION

CERTAIN NON-GAAP FINANCIAL MEASURES - unaudited

(in thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Reconciliation of GAAP "Net loss " to Non-GAAP "Net loss applicable to common shareholders, as adjusted"				
Net loss	$ (98,900)	$ (32,611)	$ (140,721)	$ (50,14
Adjustments for derivatives:				
Net losses (income)	24,035	12,271	23,208	(31,250)
Cash receipts (settlements)	(4,165)	9,238	1,625	24,189
Adjustment for acquisition transaction expenses	--	--	2,396	--
Adjustment for impairments	132,224	700	132,224	29,316
Adjustment for restructuring costs	--	1,432	--	1,284
Adjustment for loss (gain) on sale of assets, net	186	(1,573)	479	(2,407)
Adjustment for loss on extinguishment of debt	--	3,144	29,157	3,144
Adjustment for loss on firm transportation commitment	--	17,332	--	17,332
Impact of adjustments on income taxes	(53,202)	(17,235)	(66,070)	(16,345)
Preferred stock dividends	(1,725)	--	(5,175)	--
Net loss applicable to common shareholders, as adjusted (a)	$ (1,547)	$ (7,302)	$ (22,877)	$ (24,88
Net loss applicable to common shareholders, as adjusted, per share, diluted	$ (0.02)	$ (0.16)	$ (0.37)	$ (0.54)
Reconciliation of GAAP "Net loss" to Non-GAAP "Adjusted EBITDAX"				
Net loss	$ (98,900)	$ (32,611)	$ (140,721)	$ (50,14
Income tax benefit	(53,106)	(22,208)	(75,577)	(32,444)
Interest expense	20,218	14,979	56,505	44,837
Depreciation, depletion and amortization	62,450	49,331	178,355	151,888
Exploration	3,957	9,265	18,097	26,647
Share-based compensation expense (equity-classified awards)	1,010	1,282	4,781	4,233
EBITDAX	(64,371)	20,038	41,440	145,013
Adjustments for derivatives:				
Net losses (income)	24,035	12,271	23,208	(31,250)
Cash receipts (settlements)	(4,165)	9,238	1,625	24,189
Adjustment for acquisition transaction expenses	--	--	2,396	--
Adjustment for impairments	132,224	700	132,224	29,316
Adjustment for loss (gain) on sale of assets, net	186	(1,573)	479	(2,407)
Adjustment for loss on extinguishment of debt	--	3,144	29,157	3,144
Adjustment for loss on firm transportation commitment	--	17,332	--	17,332
Adjustment for other non-cash items	409	--	1,263	--
Adjusted EBITDAX (b)	$ 88,318	$ 61,150	$ 231,792	$ 185,33

(a) Net loss applicable to common shareholders, as adjusted, represents the net loss, less preferred stock dividends, adjusted to exclude the effects, net of income taxes, of non-cash changes in the fair value of derivatives, acquisition transaction expenses, impairments, restructuring costs, net gains and losses on the sale of assets, loss on extinguishment of debt and loss on firm transportation commitment. 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 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 loss before income tax expense or 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, acquisition transaction expenses, impairments, net gains and losses on the sale of assets, loss on extinguishment of debt, loss on firm transportation commitment 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 loss. Adjusted EBITDAX 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 fourth quarter and full-year 2013. These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

	First Quarter 2013	Second Quarter 2013	Third Quarter 2013	Year-to-Date 2013	Fourth Quarter 2013 Guidance			Full-Year 2013 Guidance		
Production:										
Crude oil (MBbls)	599	858	954	2,411	989	--	1,189	3,400	--	3,600
NGLs (MBbls)	234	260	254	748	227	--	257	975	--	1,005
Natural gas (MMcf)	3,565	3,778	3,591	10,933	3,327	--	3,592	14,260	--	14,525
Equivalent production (MBOE)	1,427	1,748	1,807	4,982	1,770	--	2,044	6,752	--	7,026
Equivalent daily production (BOEPD)	15,857	19,209	19,638	18,249	19,236	--	22,216	18,498	--	19,249
Percent crude oil and NGLs	58.4%	64.0%	66.9%	63.4%	68.7%	--	70.7%	64.8%	--	65.5%
Production revenues (a):										
Crude oil	$ 63.1	86.9	100.6	250.5	100.0	--	115.0	350.5	--	365.5
NGLs	$ 7.1	7.3	8.2	22.7	6.8	--	7.8	29.5	--	30.5
Natural gas	$ 12.0	15.6	12.9	40.5	11.5	--	12.5	52.0	--	53.0
Total product revenues	$ 82.2	109.7	121.6	313.6	118.4	--	135.4	432.0	--	449.0
Total product revenues ($ per BOE)	$ 57.6	62.78	67.33	62.95	66.90	--	66.24	61.49	--	66.50
Percent crude oil and NGLs	85.4%	85.8%	89.4%	87.1%	90.3%	--	90.7%	88.0%	--	88.2%
Operating expenses:										
Lease operating ($ per BOE)	$ 5.47	4.94	4.68	5.00	5.58	--	5.70	5.15	--	5.20
Gathering, processing and transportation costs ($ per BOE)	$ 2.51	1.70	1.68	1.93	1.44	--	1.84	1.80	--	1.90
Production and ad valorem taxes (percent of oil and gas revenues)	7.2%	6.4%	5.4%	6.2%	6.6%	--	7.1%	6.3%	--	6.4%
General and administrative:										
Recurring general and administrative	$ 9.9	10.2	10.6	30.6	8.9	--	10.9	39.9	--	41.9
Share-based and liability-based compensation	$ 1.1	3.1	2.1	6.3	0.8	--	1.2	6.7		7.1
Acquisition transaction expenses	--	2.4	--	2.4	0.0	--	0.0	2.4	--	2.4
Total reported G&A	$ 10.9	15.7	12.7	39.3	9.7	--	12.1	49.0	--	51.4
Exploration:										
Total reported exploration	$ 6.3	7.8	4.0	18.1	3.0	--	5.0	21.1	--	23.1
Unproved property amortization	$ 5.3	5.1	3.8	14.2	2.7	--	4.9	16.9	--	19.1
Depreciation, depletion and amortization ($ per BOE)	$ 36.14	36.80	34.57	35.80	33.35	--	33.87	34.95	--	35.47
Adjusted EBITDAX (b)	$ 60.3	83.1	88.3	231.8	88.7	--	99.7	320.5	--	331.5

Capital expenditures:										
Drilling and completion	$ 86.5	116.3	111.9	314.7	118.3	--	142.3	433.0	--	457.0
Pipeline, gathering, facilities	$ 3.0	6.8	1.7	11.4	6.6	--	8.4	18.0	--	19.8
Seismic (c)	$ 1.0	1.0	0.9	2.9	0.1	--	0.3	3.0	--	3.2
Lease acquisitions, field projects and other	$ 5.1	21.3	5.3	31.7	14.3	--	18.3	46.0	--	50.0
Total capital expenditures	$ 95.6	145.4	119.7	360.7	139.3	--	169.3	500.0	--	530.0
End of period debt outstanding	$ 633.1	1,142.0	1,203.0	1,203.0	1,260.0	--	1,270.0	1,260.0	--	1,270.0
Interest expense:										
Total reported interest expense	$ 14.5	21.8	20.2	56.5	23.5	--	24.5	80.0	--	81.0
Cash interest expense	$ 13.5	20.9	19.3	53.7	22.3	--	22.8	76.0	--	76.5
Preferred stock dividends paid	$ 1.7	1.7	1.7	5.1	1.7	--	1.7	6.9	--	6.9
Income tax benefit rate	34.9%	35.0%	34.9%	34.9%	34.9%	--	35.0%	34.9%	--	35.0%

(a) Assumes average benchmark prices of $98.00 per barrel for crude oil and $3.67 per MMBtu for natural gas in the fourth quarter of 2013, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments. NGL realized pricing is assumed to be $30.49 per barrel in the fourth quarter of 2013.

(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 2013	Collars	15,000	3.67	4.37
First quarter 2014	Collars	5,000	4.00	4.50
Fourth quarter 2013	Swaps	10,000	4.04	
First quarter 2014	Swaps	10,000	4.28	
Second quarter 2014	Swaps	15,000	4.10	
Third quarter 2014	Swaps	15,000	4.10	
Fourth quarter 2014	Swaps	5,000	4.50	
First quarter 2015	Swaps	5,000	4.50	
Crude oil:		(barrels)	($ / barrel)	
Fourth quarter 2013	Collars	2,400	91.04	100.02
First quarter 2014	Collars	1,500	93.33	102.80
Second quarter 2014	Collars	1,500	93.33	102.80
Fourth quarter 2013	Swaps	7,000	95.94	95.94
First quarter 2014	Swaps	7,500	93.86	93.86
Second quarter 2014	Swaps	7,500	93.86	93.86
Third quarter 2014	Swaps	8,000	93.18	93.18
Fourth quarter 2014	Swaps	8,000	93.18	93.18
First quarter 2015	Swaps	3,000	91.92	91.92
Second quarter 2015	Swaps	3,000	91.92	91.92
Third quarter 2015	Swaps	2,000	91.48	91.48
Fourth quarter 2015	Swaps	2,000	91.48	91.48

First quarter 2014	Swaption (a)	812	100.00
Second quarter 2014	Swaption (a)	812	100.00
Third quarter 2014	Swaption (a)	812	100.00
Fourth quarter 2014	Swaption (a)	812	100.00

(a) 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 2014 is higher than or equal to $100.00 per barrel on December 31, 2013, the counterparty will exercise its option to enter into a fixed price swap at $100.00 per barrel for calendar year 2014, at which point the contract functions as a fixed price swap. If the forward commodity price for calendar year 2014 is lower than $100.00 per barrel on December 31, 2013, the option expires and no fixed price swap is in effect.

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 2013 would increase or decrease by approximately $3.2 million. In addition, we estimate that for every $10.00 per barrel increase or decrease in the crude oil price, operating income for 2013 would increase or decrease by approximately $10.2 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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