May 2, 2012

Penn Virginia Corporation Announces First Quarter 2012 Results; Provides Updates of Operations and Full-Year 2012 Guidance

46 Percent Increase in Adjusted EBITDAX Over the Prior Year Quarter

Oil / Liquids Represented 42 Percent of Production and 82 Percent of Product Revenues During the Quarter

192 Percent Increase in Oil Production over the Prior Year Quarter

Successful Exploration of Our Oil-Rich Eagle Ford Shale Position in Lavaca County

Borrowing Base Redetermined at the Expected $300 Million Level

Sale Process Underway for Liquids-Rich, Largely Non-Operated Granite Wash and Other Mid-Continent Assets

2012 Production Guidance Affirmed; 2012 Adjusted EBITDAX Guidance Increased

RADNOR, Pa.-- Penn Virginia Corporation (NYSE: PVA) today reported financial and operational results for the three months ended March 31, 2012 and provided an update of full-year 2012 guidance.

First Quarter 2012 Highlights

First quarter 2012 results, as compared to first quarter 2011 results, were as follows:

- Oil and natural gas liquids (NGLs) production of 763 thousand barrels of oil equivalent (MBOE), or 42 percent of total equivalent production, an increase of 87 percent compared to 408 MBOE, or 20 percent of total equivalent production
- Product revenues from the sale of natural gas, crude oil and NGLs of $82.7 million, or $7.60 per thousand cubic feet of natural gas equivalent (Mcfe), an increase of 22 percent compared to $67.7 million, or $5.56 per Mcfe (37 percent increase in per unit revenues)
- Oil and NGL revenues of $67.8 million, or 82 percent of product revenues, an increase of 156 percent compared to $26.5 million, or 39 percent of product revenues
- Gross operating margin, a non-GAAP (generally accepted accounting principles) measure defined as total product revenues less total direct operating expenses, of $5.08 per Mcfe, an increase of 68 percent compared to $3.02 per Mcfe
- Adjusted EBITDAX, a non-GAAP measure, of $64.2 million, an increase of 46 percent

compared to $44.1 million
- Operating loss of $3.4 million compared to a loss of $28.5 million
- Net loss of $11.9 million, or $0.26 per diluted share, compared to a loss of $26.3 million, or $0.58 per diluted share
- Adjusted net loss, a non-GAAP measure which excludes the effects of changes in derivatives fair value, restructuring costs and other gains or losses that affect comparability to the prior year period, of $7.1 million, or $0.15 per diluted share, compared to a loss of $23.1 million, or $0.51 per diluted share

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

Recent operational highlights are as follows:

- 10 (8.3 net) Eagle Ford Shale wells have been completed since the middle of February, bringing the total to 44 (36.6 net) producing Eagle Ford Shale wells.
    - The average peak gross production rate per well for 40 of these wells, which had full-length laterals, was approximately 1,000 barrels of oil equivalent (BOE) per day (BOEPD)
    - The initial 30-day average gross production rate for 35 of these 40 wells with sufficient production history was approximately 650 BOEPD
- Two drilling rigs are currently drilling the 46th and 47th Eagle Ford Shale wells, with one well waiting on completion (WOC)
- Eagle Ford Shale production was approximately 9,200 (5,800 net) BOEPD during the first quarter of 2012, with oil comprising approximately 88 percent, NGLs approximately six percent and natural gas approximately six percent
- The first two “earning” wells on our 13,500-acre area of mutual interest (AMI) in Lavaca County, Texas were completed and turned in line during April, with the third well currently being drilled

Management Comment

H. Baird Whitehead, President and Chief Executive Officer stated, “Our successful transition from being predominantly a natural gas producer to being a more significant oil and NGL producer is clearly benefiting us, as evidenced by our much improved first quarter results. Oil and liquids production increased 87 percent over the prior year quarter and 15 percent from the fourth quarter of 2011. During the quarter, oil revenues alone were nearly four times natural gas revenues, excluding the impact of our hedges, and we expect oil and liquids to comprise approximately 84 percent of product revenues and approximately 43 percent of production in 2012. Our Eagle Ford Shale play, which has driven this oily transformation, has grown significantly over the past 18 months, and our recent early success in Lavaca County de-risks a portion of this acreage with the potential for drilling-related proved reserve additions as the year progresses.”

Mr. Whitehead added, “Building on this success, we currently plan to devote approximately 89 percent of estimated 2012 capital expenditures to the Eagle Ford Shale. Consistent with our previously announced plan to sell assets and to further improve liquidity, we have commenced a sale process for our largely non-operated and liquids-rich assets in the Mid-Continent region, which primarily consist of our Granite Wash properties. In addition, we continue to hedge our oil position and currently have approximately 70 percent of our

anticipated oil production hedged for the final three quarters of 2012 at an average price of approximately $102 per barrel."

First Quarter 2012 Financial and Operational Results

Overview of Financial Results

The $3.4 million operating loss was $25.1 million, or 88 percent, lower than the $28.5 million loss in the prior year quarter, due primarily to a $41.3 million increase in oil and liquids revenues, a $21.6 million decrease in exploration expense and a $3.5 million decrease in total direct operating expenses. The positive effect of these items was partially offset by a $26.3 million decrease in natural gas revenues and a $16.0 million increase in depreciation, depletion and amortization (DD&A) expense. Oil and NGL revenues were $67.8 million in the first quarter of 2012, 156 percent higher than the $26.5 million in the prior year quarter and 26 percent higher than the $53.9 million in the fourth quarter of 2011. Oil and NGL revenues were 82 percent of product revenues in the first quarter of 2012, compared to 39 percent in the prior year quarter and 70 percent in the fourth quarter of 2011.

Pricing

Our first quarter 2012 realized oil price of $107.05 per barrel was 21 percent higher than the $88.37 per barrel price in the prior year quarter and nine percent higher than the $98.49 per barrel price in the fourth quarter of 2011. Our first quarter 2012 realized NGL price of $42.24 per barrel was six percent lower than the $45.11 per barrel price in the prior year quarter and seven percent lower than the $45.46 per barrel price in the fourth quarter of 2011. Our first quarter 2012 realized natural gas price of $2.37 per thousand cubic feet (Mcf) was 44 percent lower than the $4.23 per Mcf price in the prior year quarter and 32 percent lower than the $3.46 per Mcf price in the fourth quarter of 2011. Adjusting for oil and gas hedges, our first quarter 2012 effective oil price was $106.85 per barrel and our effective natural gas price was $3.65 per Mcf, or a decrease of $0.20 per barrel and an increase of $1.28 per Mcf over the realized prices.

Production

As shown in the table below, production in the first quarter of 2012 was 10.9 Bcfe, or 119.5 MMcfe per day, a 12 percent decrease compared to 12.2 Bcfe, or 135.2 MMcfe per day, in the prior year quarter and a two percent increase from 10.7 Bcfe, or 116.7 MMcfe per day, in the fourth quarter of 2011. As a percentage of total equivalent production, oil and NGL volumes were 42 percent in the first quarter of 2012 compared to 20 percent in the prior year quarter and 37 percent in the fourth quarter of 2011. Oil production increased 192 percent from 188 thousand barrels (MBbls) in the prior year quarter to 549 MBbls in the first quarter of 2012. On a pro forma basis, excluding production from the Mid-Continent assets sold in 2011, production in the prior year quarter was 11.5 Bcfe, or 127.9 MMcfe per day. The pro forma decrease of 0.6 Bcfe, or six percent, was primarily the result of a 2.8 Bcfe, or 31 percent, decrease in pro forma natural gas production due to reduced natural gas drilling since mid-2010 in East Texas, Mississippi and, to a lesser extent, the Granite Wash, partially offset by a 362 MBOE (2.2 Bcfe), or 90 percent, increase in pro forma oil and NGL production.

Region / Play Type	Total and Daily Equivalent Production for the Three Months Ended					
	Mar. 31, 2012	**Mar. 31, 2011**	**Dec. 31, 2011**	**Mar. 31, 2012**	**Mar. 31, 2011**	**Dec. 31, 2011**
	(in Bcfe)			(in MMcfe per day)		
Texas	**5.3**	**3.8**	**4.9**	**58.7**	**42.5**	**53.2**
Cotton Valley/Other	*1.4*	*2.2*	*1.6*	*15.5*	*24.8*	*17.6*
Haynesville Shale	*0.8*	*1.4*	*0.9*	*8.7*	*16.0*	*9.6*
Eagle Ford Shale[1]	*3.1*	*0.1*	*2.4*	*34.6*	*1.6*	*26.0*
Appalachia	**2.1**	**2.4**	**2.2**	**22.7**	**26.3**	**23.6**
Mid-Continent[2]	**2.1**	**4.1**	**2.2**	**23.6**	**45.8**	**24.3**
Granite Wash	*2.0*	*3.1*	*2.2*	*22.0*	*33.9*	*24.4*
Mississippi	**1.3**	**1.9**	**1.4**	**14.5**	**20.7**	**15.6**
Totals	**10.9**	**12.2**	**10.7**	**119.5**	**135.2**	**116.7**
Pro Forma Totals[3]	**10.9**	**11.5**	**10.7**	**119.5**	**127.9**	**116.7**

(1) Initial production from the Eagle Ford Shale commenced in February 2011.

(2) Includes production from the Mid-Continent assets sold in 2011.

(3) Pro forma to exclude production from the Mid-Continent assets sold in 2011.

Note - Numbers may not add due to rounding.

Operating Expenses

First quarter 2012 total direct operating expenses decreased $3.5 million, or approximately 11 percent, to $27.4 million, or $2.52 per Mcfe produced, compared to $30.9 million, or $2.54 per Mcfe produced, in the prior year quarter.

- Lease operating expenses decreased by $1.1 million, or 11 percent, to $9.2 million, or $0.84 per Mcfe produced, from $10.3 million, or $0.84 per Mcfe produced, in the prior year quarter due to lower production volumes as well as the sale of higher-cost Arkoma Basin properties in August 2011. Despite the decrease in costs, the unit cost was flat due to lower production volumes.
- Gathering, processing and transportation expenses increased by approximately $0.2 million, or three percent, to $4.2 million, or $0.38 per Mcfe produced, from $4.0 million, or $0.33 per Mcfe produced, in the prior year quarter, despite lower overall production volumes, due primarily to firm transportation costs in the Appalachian region and a

prior-period adjustment related to gathering volumes in the Mid-Continent.

- Production and ad valorem taxes decreased 29 percent to $3.6 million, or 4.3 percent of product revenues, from $5.1 million, or 7.5 percent of product revenues, in the prior year quarter resulting from lower natural gas prices and lower severance tax rates for certain wells in Texas and Oklahoma.
- General and administrative (G&A) expenses, excluding share-based compensation, decreased by $1.0 million, or nine percent, to $10.5 million, or $0.97 per Mcfe produced, from $11.5 million, or $0.95 per Mcfe produced, in the prior year quarter. This decrease was due primarily to lower employee headcount and lower support costs following restructuring actions taken during 2011.

Exploration expense decreased $21.5 million, or 73 percent, to $8.0 million in the first quarter of 2012 from $29.5 million in the prior year quarter. The decrease was due primarily to a $16.4 million decrease in dry-hole costs (zero in the first quarter of 2012), a $2.4 million decrease in unproved property amortization and a $2.2 million decrease in geological and geophysical costs.

DD&A expense increased by $16.0 million, or 46 percent, to $50.8 million, or $4.67 per Mcfe produced, in the first quarter of 2012 from $34.8 million, or $2.86 per Mcfe produced, in the prior year quarter, due primarily to higher DD&A costs attributable to our Eagle Ford Shale oil wells, which is typical for this and other oily plays, as well as downward revisions in proved reserves located primarily in the Granite Wash, East Texas and Mississippi at year-end 2011.

Capital Expenditures

During the first quarter of 2012, capital expenditures were approximately $90 million, compared to $104 million in the prior year quarter and $123 million in the fourth quarter of 2011, consisting of:

- $83 million for drilling and completion activities, including 11 (9.4 net) wells, all of which were successful
- $3 million for seismic, pipeline, gathering and facilities
- $4 million for leasehold acquisitions and other

Operational Update

Eagle Ford Shale

During the first quarter of 2012, we drilled 11 (9.4 net) operated wells in the Eagle Ford Shale, all of which were successful. We currently have two rigs drilling our 46th and 47th wells, one well that is WOC and 44 (36.6 net) wells that are producing. As shown in the table below, the average peak gross production rate per well for 40 of these wells which had full-length laterals was approximately 1,000 BOEPD. The initial 30-day average gross production rate for 35 of these 40 wells with sufficient production history was approximately 650 BOEPD. Eagle Ford Shale production was approximately 9,200 (5,800 net) BOEPD during the first quarter of 2012, with oil comprising approximately 88 percent, NGLs approximately six percent and natural gas approximately six percent.

In late 2011, we announced a 13,500 acre AMI with a major oil and gas company in Lavaca

County, Texas pursuant to which, during 2012, we can earn a minimum of approximately 8,000 net acres. This would bring our Eagle Ford Shale position in Gonzales and Lavaca Counties, Texas to a minimum of approximately 31,400 (23,100 net) acres, with up to 190 total well locations assuming down-spacing is successful on a majority of our acreage.

The first two wells on the Lavaca County acreage (Effenberger #1H and Vana #1H) were completed and turned in line during April 2012. Both wells have met or exceeded our expectations with the Effenberger #1H (20 frac stages and lateral length of approximately 5,000 feet) averaging 922 BOEPD of wellhead volumes over its first nine days of production (90 percent oil and 10 percent wet gas) and the Vana #1H (13 frac stages and lateral length of approximately 3,200 feet) averaging 709 BOEPD of wellhead volumes over its first five days of production (94 percent oil and six percent wet gas). The lateral length of the Vana #1H well was less than expected by approximately 1,600 feet due to an issue with getting casing to the total depth drilled. Taking into account the lateral lengths, both wells appear to have similar production characteristics during the initial flowback of frac fluids and are comparable to well results experienced in nearby Gonzales County. Both wells are significantly choked with the flowing pressure on the Effenberger #1H well at the end of the nine days of approximately 3,450 pounds per square inch (psi) and the flowing pressure on the Vana #1H well at the end of the five days of approximately 2,300 psi, as the recovery of fluid continues. A third well in Lavaca County (Schacherl #1H) is currently being drilled, with three additional wells expected to be drilled during 2012.

Our full-year 2012 guidance anticipates 32 (27.6 net) new wells in the Eagle Ford Shale, including the wells drilled during the first quarter of 2012. Efforts continue to expand our Eagle Ford Shale position through additional leasing and selective acquisitions.

			Cumulative Gross Production[4]		**Peak Gross Daily Production Rates[4]**		**30-Day Average Gross Daily Production Rates[4]**	
Well Name	**Lateral Length**	**Frac Stages**	**Equivalent Production**	**Days On Line**	**Oil Rate**	**Equivalent Rate**	**Oil Rate**	**Equivalen Rate**
	Feet		*BOE*		*BOPD*	*BOEPD*	*BOPD*	*BOEPD*
Previously Reported On-Line Wells								
Gardner #1H	4,792	16	159,852	451	1,084	1,247	732	881
Hawn Holt #1H	4,352	15	103,270	357	759	837	606	668

Hawn Holt #4H	4,106	14	67,850	354	534	582	357	394
Hawn Holt #6H	4,166	17	69,971	325	670	711	342	370
Hawn Holt #2H	4,476	17	104,452	324	869	986	668	728
Hawn Holt #9H	4,453	18	132,210	373	1,652	1,877	1,044	1,153
Hawn Holt #10H	3,913	16	97,568	296	1,080	1,188	771	839
Hawn Holt #5H	3,950	16	54,657	288	474	528	321	349
Hawn Holt #3H	3,800	15	64,309	288	607	651	478	522
Munson Ranch #1H	4,163	17	150,240	279	1,755	1,921	1,207	1,315
Munson Ranch #3H	3,953	16	113,041	278	1,448	1,538	1,007	1,092
Hawn Holt #11H	3,931	16	82,235	274	1,120	1,190	786	860
Dickson Allen #1H	3,953	15	46,973	243	465	508	358	393
Hawn Holt #7H	4,345	18	60,259	244	730	798	493	541
Hawn Holt #12H	3,320	18	75,296	235	1,458	1,495	619	668
Hawn Holt #13H	2,805	11	62,938	222	1,347	1,399	591	650
Cannonade Ranch #1H	4,403	18	48,889	227	377	403	255	274
Hawn Holt #15H	4,153	17	100,782	203	1,191	1,298	779	838
Hawn Holt #8H	4,203	17	49,170	195	427	492	361	409
Dickson Allen #2H	3,853	16	65,387	196	552	601	460	516
Gardner #2H	2,953	12	31,729	170	551	579	312	346
Munson Ranch #2H	3,953	16	57,838	166	819	869	515	572
Rock Creek Ranch #1H	3,444	14	68,261	140	1,158	1,257	639	708
Munson Ranch #8H	3,403	14	43,347	133	914	964	561	606
Munson Ranch #4H	3,864	16	62,588	132	1,317	1,416	807	870

Munson Ranch #6H	3,415	14	61,917	123	1,717	1,808	845	928
Schaefer #2H	3,707	12	23,450	110	586	638	305	334
Schaefer #3H	2,903	12	42,253	108	1,035	1,129	546	604
Schaefer #1H	2,992	13	40,349	109	871	941	536	584
Munson Ranch #5H	3,153	13	51,446	88	1,063	1,164	723	791
Munson Ranch #7H	3,153	13	36,295	88	757	824	506	548
Hawn Dickson #1H	3,153	13	30,520	84	923	969	472	509
New On-Line Wells								
D. Foreman #1H	3,398	14	35,044	66	1,133	1,202	637	678
Rock Creek Ranch #2H	3,455	14	26,543	55	700	791	---	---
Culpepper #2H	4,903	20	18,649	49	531	560	388	413
Henning #1H	3,703	15	21,412	37	1,056	1,115	565	614
Rock Creek Ranch #6H	3,150	13	16,471	20	857	960	---	---
Rock Creek Ranch #5H	3,203	13	15,542	20	870	969	---	---
Effenberger #1H(5)	4,950	20	7,517	9	845	922	---	---
Vana #1H(5)	3,192	13	2,817	5	655	709	---	---
Averages	3,778	15	60,083	184	924	1,001	588	645
Maximums	4,950	20	159,852	451	1,755	1,921	1,207	1,315
Minimums	2,805	11	2,817	5	377	403	255	274
Other Wells								
Cannonade Ranch #3H(6)	3,451	12	7,192	91	205	228	73	81

Munson Ranch #9H[6]	1,700	7	13,756	123	393	400	184	202
Rock Creek Ranch #3H[6]	1,903	9	12,886	58	341	384	248	284
Rock Creek Ranch #4H[6]	2,403	10	21,407	54	243	291	379	451
Rock Creek Ranch #9H	WOC							
Schacherl #1H[5]	Drilling							
Rock Creek Ranch #10H	Drilling							

(4) Wellhead rates only; the natural gas associated with these wells is yielding approximately 145 barrels of NGLs per million cubic feet (MMcf).

(5) Wells located in Lavaca County; all other wells are located in Gonzales County.

(6) The Cannonade Ranch #3H had been shut-in to address H_2S production issues, while the Munson Ranch #9H, Rock Creek Ranch #3H and #4H had short laterals and fewer frac stages. As a result, production data for these four wells has been excluded from the statistics.

Full-Year 2012 Guidance

Full-year 2012 guidance highlights are as follows:

- Full-year 2012 production is expected to be 40.0 to 43.0 Bcfe, unchanged from previous guidance
  - Crude oil and liquids are expected to comprise approximately 43 percent of total production during 2012
- Full-year 2012 product revenues are expected to be $292 to $316 million, compared to $288 to $319 million of previous guidance, excluding the impact of our hedges
  - Crude oil and NGL product revenues are expected to be approximately 84 percent of total product revenues during 2012
  - Approximately 70 percent of estimated crude oil production volumes and 25 percent of estimated natural gas production volumes are hedged over the remaining three quarters of 2012 at weighted average prices of $102.21 per

barrel and $5.27 per Mcf, respectively
    - 2012 settlements of current commodity hedges are expected to result in cash receipts of approximately $28 million
- Full-year 2012 Adjusted EBITDAX, a non-GAAP measure, is expected to be $220 to $240 million, compared to previous guidance of $200 to $240 million
- Full-year 2012 cash flow from operating activities is expected to be $185 to $205 million, compared to previous guidance of $175 to $205 million (both ranges include an anticipated $30 million income tax refund in the fourth quarter of 2012)
- Full-year 2012 capital expenditures are expected to be $300 to $325 million, unchanged from previous guidance
    - Approximately 89 percent of the 2012 capital expenditures are expected to be allocated to the Eagle Ford Shale and approximately four percent to the Mid-Continent

Please see the Guidance Table included in this release for guidance estimates for full-year 2012. These estimates are meant to provide guidance only and are subject to revision as our operating environment changes.

Capital Resources and Liquidity, Interest Expense and Impact of Derivatives

As of March 31, 2012, we had total debt with a carrying value of approximately $718 million ($724 million aggregate principal amount), consisting of $294 million of 10.375 percent senior unsecured notes due 2016 ($300 million principal amount), $300 million principal amount of 7.25 percent senior unsecured notes due 2019, $5 million principal amount of 4.5 percent convertible senior subordinated notes due 2012 (classified as a current liability) and $119 million of borrowings under our revolving credit facility (Revolver). Our indebtedness at March 31, 2012 was approximately 46 percent of book capitalization and 3.0 times the latest twelve months' Adjusted EBITDAX of $242.7 million, a reduction from 3.2 times at year-end 2011.

We have no material debt maturities until 2016. Our business strategy for 2012 requires capital expenditures in excess of our anticipated operating cash flows, although within the Revolver's borrowing base, as shown in the table below.

Year Ending December 31, 2012 *In millions*	**Guidance Range** **Low**	 **High**
Net cash provided by operating activities *(7)*	**$ 185.0**	**$ 205.0**
Less: Common stock dividends	*(10.3)*	*(10.3)*
Less: Repayment of 4.5 percent convertible senior subordinated notes due December 2012	*(4.9)*	*(4.9)*
Less: Capitalized interest	*(2.0)*	*(2.0)*
Cash flows available for investment	**$ 167.8**	**$ 187.8**
Less: Capital expenditures (including seismic expenditures)	*(325.0)*	*(300.0)*
Plus: Seismic expenditures (included in cash flows from operating activities)	*10.0*	*5.0*
Capital outspend of cash flows	**$ (147.2)**	**$ (107.2)**

(7) Please see the Guidance Table included in this release for guidance estimates for full-year 2012, which include production of 40.0 to 43.0 Bcfe (6.7 to 7.2 million BOE) and average benchmark prices of $95.75 per barrel for crude oil, $42.29 per barrel for NGLs and $2.40 per MMBtu for natural gas, adjusted to reflect any premium or discount for quality, basin differentials and other adjustments. In addition, cash flows from operating activities include an estimated $30 million cash income tax refund expected to be received in the fourth quarter of 2012.

We plan to fund our 2012 capital program with operating cash flows, proceeds from asset sales and borrowings under the Revolver.

Borrowing Base Redetermination

In August 2011, we entered into the Revolver, which matures in August 2016. The Revolver provided for a $300 million commitment amount and initial borrowing base of $380 million. Following the semi-annual redetermination in April 2012 and as a result of decreased natural gas prices, the borrowing base was lowered to $300 million, which is at the upper end of our previously disclosed expectations. Our business plan anticipates us borrowing amounts under the Revolver during the remainder of 2012 that are within this redetermined borrowing base. As of April 30, 2012, we had approximately $22 million of cash on hand and approximately $151 million of unused borrowing capacity under the Revolver, net of outstanding letters of credit of $1.7 million.

Planned Asset Sale

We expect to reduce our indebtedness and supplement liquidity under the Revolver with proceeds from the sale of non-core assets. We recently engaged a financial advisor to assist us in the sale of the majority of our remaining Mid-Continent assets. The sales process for these liquids-rich and largely non-operated properties has commenced. The properties anticipated to be sold include our Granite Wash production and reserves, as well as a few exploratory prospects. However, we will retain our Viola Limestone prospect acreage, which we expect to drill late in the second quarter of this year. Based on internal estimates, the properties to be divested have proved reserves of approximately 123 Bcfe, 46 percent of which are NGLs and oil, and 81 gross remaining drilling locations. First quarter 2012 production for these assets was 23.6 MMcfe per day, 48 percent of which was NGLs and oil. No assurances can be given that a sale will be completed or as to the timing of or the net proceeds from such a sale.

Explanation of Non-GAAP Gross Operating Margin per Mcfe

Gross operating margin is a non-GAAP financial measure under SEC regulations which represents total product revenues less total direct operating expenses. Gross operating margin per Mcfe is equal to gross operating margin divided by total natural gas, crude oil and NGL production. Gross operating margin is not adjusted for the impact of hedges. We believe that gross operating margin per Mcfe 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.

First Quarter 2012 Financial and Operational Results Conference Call

A conference call and webcast, during which management will discuss first quarter 2012 financial and operational results, is scheduled for Thursday, May 3, 2012 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 1-866-630-9986 five to 10 minutes before the scheduled start of the conference call (use the passcode 8452642), 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 888-203-1112 (international: 719-457-0820) and using the replay code 8452642. 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 primarily in the development, exploration and production of natural gas and oil in various domestic onshore regions including Texas, Appalachia, the Mid-Continent and Mississippi. 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 natural gas, natural gas liquids and oil; our ability to develop, explore for, acquire and replace oil and 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 natural gas, natural gas liquids and oil; reductions in the borrowing base under our Revolver; 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 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 March 31,	
	2012	2011
Revenues		
Natural gas	$ 14,886	$ 41,189
Crude oil	58,723	16,583
Natural gas liquids (NGLs)	9,071	9,921
Total product revenues	82,680	67,693
Gain on sales of property and equipment	756	480
Other	975	410
Total revenues	84,411	68,583
Operating expenses		
Lease operating	9,143	10,277
Gathering, processing and transportation	4,154	4,028
Production and ad valorem taxes	3,580	5,064
General and administrative (excluding share-based compensation)	10,526	11,556
Total direct operating expenses	27,403	30,925
Share-based compensation (a)	1,615	1,796
Exploration	7,998	29,548
Depreciation, depletion and amortization	50,817	34,843
Total operating expenses	87,833	97,112
Operating loss	(3,422)	(28,529)
Other income (expense)		
Interest expense	(14,774)	(13,484)
Derivatives	(305)	1,328
Other	1	144

Loss before income taxes	(18,500)	(40,541)
Income tax benefit	6,601	14,201
Net loss	$(11,899)	$(26,340)
Loss per share:		
Basic	$(0.26)	$(0.58)
Diluted	$(0.26)	$(0.58)
Weighted average shares outstanding, basic	45,945	45,687
Weighted average shares outstanding, diluted	45,945	45,687

	Three months ended March 31,	
	2012	2011
Production		
Natural gas (MMcf)	6,294	9,726
Crude oil (MBbls)	549	188
NGLs (MBbls)	215	220
Total natural gas, crude oil and NGL production (MMcfe)	10,874	12,171
Prices		
Natural gas ($ per Mcf)	$2.37	$4.23
Crude oil ($ per Bbl)	$107.05	$88.37
NGLs ($ per Bbl)	$42.24	$45.11
Prices - Adjusted for derivative settlements		
Natural gas ($ per Mcf)	$3.65	$4.95
Crude oil ($ per Bbl)	$106.85	$87.17
NGLs ($ per Bbl)	$42.24	$45.11

(a) Our 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. Share-based compensation expense related to liability-classified awards payable in cash is included in general and administrative expense.

PENN VIRGINIA CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS - unaudited
(in thousands)

	As of March 31, 2012	December 31, 2011
Assets		
Current assets	$ 128,546	$ 145,346
Net property and equipment	1,809,291	1,777,575
Other assets	20,866	20,132
Total assets	$ 1,958,703	$ 1,943,053
Liabilities and shareholders' equity		
Current liabilities (a)	$ 119,634	$ 106,607
Revolving credit facility	119,000	99,000
Senior notes due 2016	293,848	293,561
Senior notes due 2019	300,000	300,000
Other liabilities and deferred income taxes	292,760	297,576
Total shareholders' equity	833,461	846,309
Total liabilities and shareholders' equity	$ 1,958,703	$ 1,943,053

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

	Three months ended March 31, 2012	2011
Cash flows from operating activities		
Net loss	$ (11,899)	$ (26,340)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	50,817	34,843
Derivative contracts:		
Net losses (gains)	305	(1,328)
Cash settlements	7,981	6,744
Deferred income tax benefit	(6,601)	(14,201)
Gain on the sales of property and equipment, net	(756)	(480)
Non-cash exploration expense	8,171	26,999
Non-cash interest expense	1,015	3,272

Share-based compensation	1,615	1,796
Other, net	56	236
Changes in operating assets and liabilities	19,997	(2,105)
Net cash provided by operating activities	70,701	29,436
Cash flows from investing activities		
Capital expenditures - property and equipment	(94,469)	(100,729)
Proceeds from the sales of property, plant and equipment, net	778	360
Other, net	-	100
Net cash used in investing activities	(93,691)	(100,269)
Cash flows from financing activities		
Dividends paid	(2,586)	(2,576)
Proceeds from revolving credit facility borrowings	23,000	-
Repayment of revolving credit facility borrowings	(3,000)	-
Other, net	-	838
Net cash provided by (used in) financing activities	17,414	(1,738)
Net decrease in cash and cash equivalents	(5,576)	(72,571)
Cash and cash equivalents - beginning of period	7,512	120,911
Cash and cash equivalents - end of period	$1,936	$48,340
Supplemental disclosures of cash paid for:		
Interest (net of amounts capitalized)	$557	$387
Income taxes (net of refunds received)	$(301)	$(120)

(a) The convertible notes are due in November 2012 and are included in current liabilities.

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

	Three months ended March 31,	
	2012	2011
Reconciliation of GAAP "Net loss" to Non-GAAP "Net loss, as adjusted"		
Net loss	$(11,899)	$(26,340)
Adjustments for derivatives:		
Net losses (gains) included in net loss	305	(1,328)
Cash settlements	7,981	6,744
Adjustment for restructuring costs	-	18

Adjustment for net loss (gain) on sale of assets	(756)	(480)
Impact of adjustments on income taxes	(2,687)	(1,735)
Net loss, as adjusted (a)	$(7,056)	$(23,121)
Net loss, as adjusted, per share, diluted	$(0.15)	$(0.51)

Reconciliation of GAAP "Net loss" to Non-GAAP "Adjusted EBITDAX"

Net loss	$(11,899)	$(26,340)
Income tax benefit	(6,601)	(14,201)
Interest expense	14,774	13,484
Depreciation, depletion and amortization	50,817	34,843
Exploration	7,998	29,548
Share-based compensation expense	1,615	1,796
EBITDAX	56,704	39,130
Adjustments for derivatives:		
Net gains included in net income	305	(1,328)
Cash settlements	7,981	6,744
Adjustment for net loss (gain) on sale of assets	(756)	(480)
Adjusted EBITDAX (b)	$64,234	$44,066

(a) Net loss, as adjusted, represents the net loss adjusted to exclude the effects of non-cash changes in the fair value of derivatives, restructuring costs, 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 loss, 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.

(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, 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. 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 full-year 2012. These estimates are meant to provide guidance only and are subject to change as PVA's operating environment changes.

	First Quarter 2012	Full-Year 2012 Guidance	
Production:			
Natural gas (Bcf)	6.3	23.0	- 24.4
Crude oil (MBbls)	549	2,100	- 2,275
NGLs (MBbls)	215	733	- 825
Equivalent production (Bcfe)	10.9	40.0	- 43.0
Equivalent daily production (MMcfe per day)	119.5	109.3	- 117.8
Equivalent production (MBOE)	1,812	6,667	- 7,167
Equivalent daily production (MBOE per day)	19.9	18.2	- 19.6
Percent crude oil and NGLs	42.1 %	42.5 %	- 43.3 %
Production revenues (a):			
Natural gas	$ 14.9	46.0	- 51.0
Crude oil	$ 58.7	214.0	- 230.0
NGLs	$ 9.1	32.0	- 35.0
Total product revenues	$ 82.7	292.0	- 316.0
Total product revenues ($ per Mcfe)	$ 7.60	7.30	- 7.35
Total product revenues ($ per BOE)	$ 45.62	43.80	- 44.09
Percent crude oil and NGLs	$ 82.0 %	82.5 %	- 85.4 %
Operating expenses:			
Lease operating ($ per Mcfe)	$ 0.84	0.80	- 0.85
Lease operating ($ per BOE)	$ 5.04	4.80	- 5.10
Gathering, processing and transportation costs ($ per Mcfe)	$ 0.38	0.31	- 0.36
Gathering, processing and transportation costs ($ per BOE)	$ 2.29	1.86	- 2.16
Production and ad valorem taxes (percent of oil and gas revenues)	4.3 %	4.0 %	- 4.5 %
General and administrative:			

Recurring general and administrative	$ 10.5	39.0	- 41.0
Share-based compensation	$ 1.6	6.5	- 7.0
Restructuring	$ -		
Total reported G&A	$ 12.1	45.5	- 48.0
Total reported exploration	$ 8.0	43.0	- 46.0
Unproved property amortization	$ 8.2	35.0	- 36.0
Depreciation, depletion and amortization ($ per Mcfe)	$ 4.67	4.75	- 5.00
Depreciation, depletion and amortization ($ per BOE)	$ 28.04	28.50	- 30.00
Adjusted EBITDAX (b)	$ 64.2	220.0	- 240.0
Net cash provided by operating activities (c)	$ 70.7	185.0	- 205.0
Capital expenditures:			
Drilling and completion	$ 82.6	265.0	275.0
Pipeline, gathering, facilities	$ 3.9	10.0	- 15.0
Seismic (d)	$ (0.4)	5.0	- 10.0
Lease acquisitions, field projects and other	$ 4.3	20.0	- 25.0
Total oil and gas capital expenditures	$ 90.4	300.0	- 325.0
End of period debt outstanding	$ 717.6		
Effective interest rate	8.5 %		
Income tax benefit rate	35.7 %	38.0 %	- 39.0 %

(a) Assumes average benchmark prices of $95.75 per barrel for crude oil, $42.29 per barrel for NGLs and $2.40 per MMBtu for natural gas, prior to any premium or discount for quality, basin differentials, the impact of hedges and other adjustments.

(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 from continuing operations.

(c) Includes an estimated $30 million cash income tax refund expected to be received in the fourth quarter of 2012.

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

PENN VIRGINIA CORPORATION
GUIDANCE TABLE - unaudited - (continued)

Note to Guidance Table:

The following table shows our current derivative positions.

	Instrument Type	Average Volume Per Day	Weighted Average Price Floor/ Swap	Ceiling
Natural gas:		**(MMBtu)**	**($ / MMBtu)**	
Second quarter 2012	Swaps	20,000	5.31	
Third quarter 2012	Swaps	20,000	5.31	
Fourth quarter 2012	Swaps	10,000	5.10	
Crude oil:		**(barrels)**	**($ / barrel)**	
Second quarter 2012	Collars	1,000	90.00	97.00
Third quarter 2012	Collars	1,000	90.00	97.00
Fourth quarter 2012	Collars	1,000	90.00	97.00
First quarter 2013	Collars	1,000	90.00	100.00
Second quarter 2013	Collars	1,000	90.00	100.00
Third quarter 2013	Collars	1,000	90.00	100.00
Fourth quarter 2013	Collars	1,000	90.00	100.00
Second quarter 2012	Swaps	3,000	103.05	
Third quarter 2012	Swaps	3,000	104.40	
Fourth quarter 2012	Swaps	3,000	104.40	
First quarter 2013	Swaps	2,250	103.51	
Second quarter 2013	Swaps	2,250	103.51	
Third quarter 2013	Swaps	1,500	102.77	
Fourth quarter 2013	Swaps	1,500	102.77	
First quarter 2014	Swaps	2,000	100.44	
Second quarter 2014	Swaps	2,000	100.44	
Third quarter 2014	Swaps	1,500	100.20	
Fourth quarter 2014	Swaps	1,500	100.20	
First quarter 2013	Swaption	1,100	100.00	
Second quarter 2013	Swaption	1,000	100.00	
Third quarter 2013	Swaption	900	100.00	
Fourth quarter 2013	Swaption	750	100.00	
First quarter 2014	Swaption	812	100.00	
Second quarter 2014	Swaption	812	100.00	
Third quarter 2014	Swaption	812	100.00	
Fourth quarter 2014	Swaption	812	100.00	

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 remainder of 2012 would increase or decrease by approximately $17 million. In addition, we estimate that for every $10.00 per barrel increase or decrease in the crude oil price, operating income for the remainder of 2012 would increase or decrease by approximately $15 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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Source: Penn Virginia Corporation