

Edgar Filing: Penn Virginia GP Holdings, L.P. - Form 425

Penn Virginia GP Holdings, L.P.  
Form 425  
October 28, 2010

**Filed by Penn Virginia Resource Partners, L.P. pursuant to Rule 425 under the  
Securities Act of 1933 and  
deemed filed pursuant to Rule 14a-12 under the Securities Exchange Act of 1934**

**Subject Company: Penn Virginia GP Holdings, L.P.**

**Commission File No.: 001-33171**

Penn Virginia Resource Partners, L.P  
American Association of  
Individual Investors  
Philadelphia Chapter  
10/26/2010  
NYSE: PVR  
[www.pvresource.com](http://www.pvresource.com)

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#### Forward-Looking Statements

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 volatility of commodity prices for natural gas, NGLs and coal; our ability to access external sources of capital; any impairment or write-downs of our assets; the relationship between natural gas, NGL and coal prices; the projected demand for and supply of

gas, NGLs and coal; competition among producers in the coal industry generally and among natural gas midstream companies; extent to which the amount and quality of actual production of our coal differs from estimated recoverable coal reserves; our ability to generate sufficient cash from our businesses to maintain and pay the quarterly distribution to our general partner and our unitholders; the experience and financial condition of our coal lessees and natural gas midstream customers, including our lessees' ability to satisfy their royalty, environmental, reclamation and other obligations to us and others; operating risks, including unanticipated geological problems, incidental to our coal and natural resource management or natural gas midstream businesses; our ability to acquire new coal reserves or natural gas midstream assets and new sources of natural gas supply and connections to third-party pipelines on satisfactory terms; our ability to retain existing or acquire new natural gas midstream customers and coal lessees; the ability of our lessees to produce sufficient quantities of coal on an economic basis from our reserves and obtain favorable contracts for such production; the occurrence of unusual weather or operating conditions including force majeure events; delays in anticipated start-up dates of our lessees' mining operations and related coal infrastructure projects and new processing plants in our natural gas midstream business; environmental risks affecting the mining of coal reserves or the production, gathering and processing of natural gas; the timing of receipt of necessary governmental permits by us or our lessees; hedging results; accidents; changes in governmental regulation or enforcement practices, especially with respect to environmental, health and safety matters, including respect to emissions levels applicable to coal-burning power generators; uncertainties relating to the outcome of current and future litigation regarding mine permitting; risks and uncertainties relating to general domestic and international economic (including inflation, interest rates and financial and credit markets) and political conditions (including the impact of potential terrorist attacks) and other risks set forth in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission, including our Annual Report on Form 10-K for the year ended December 31, 2009. Management believes that 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.

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Diversified, Relatively Low-Risk Asset Base  
Strategically Located Coal Reserves and Midstream Assets  
Stable and Predictable Coal Royalty Business  
Solid Balance Sheet and Attractive Yield  
Stable Cash Flows and Distribution Coverage  
Well  
Positioned

to  
Capitalize  
on  
Partnership  
Momentum  
&  
Industry  
Trends  
Hedged Midstream Business with Growing Fee-Based Volumes  
Key Investment Highlights

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Current Structure  
Penn Virginia  
Resource Partners,  
L.P.  
(NYSE: PVR)  
Public  
Unitholders

32.7 MM

Common Units

60.4% LP interest

Penn Virginia

GP Holdings, L.P.

(NYSE: PVG)

Public

Unitholders

39.1 MM

Common Units

100% LP interest

Penn

Virginia

Resource

GP, LLC

100% ownership

2% GP Interest

and Incentive

Distribution Rights

37.6% LP interest

19.6 MM PVR Common Units

Notes:

1)

Chart displays simplified organizational structure

2)

Units outstanding and ownership interests are rounded

approximations

Penn Virginia

Operating Co., LLC

and its subsidiaries



5  
Coal royalty  
business,  
not  
coal  
mining  
Managed coal properties since 1882  
Controls 829 MM tons of high quality coal

reserves (24 year R/P ratio)

Long-term leases with experienced operators

Ancillary businesses include coal services,  
timber and gas royalties

Coal & Natural Resource Management

~ 2/3 of 2009 Adjusted EBITDA

(1)

Natural Gas Midstream

~ 1/3 of 2009 Adjusted EBITDA

(1)

\$185 million of 2009 Adjusted EBITDA

(1)

Traditional gathering and processing business

Assets are located in attractive natural gas

basins with long-lived reserves

4,118 miles of pipelines

6 processing facilities

400 MMcfd of capacity

Average throughput volume 332 MMcfd in

2009

(1)

Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income and

Overview

6  
Coal & Natural Resource Management  
San Juan  
Basin  
Northern  
Appalachia  
Illinois  
Basin

Central

Appalachia

Coal reserves located in major supply basins

Access to major coal hauling railroads and inland waterways

Close proximity to power generation facilities

Gathering systems located in major gas basins

Reserves in Oklahoma, North Texas and East Texas are moderately declining and long-lived

Significant growth potential from Marcellus Shale

Crossroads

Arkoma

Panhandle

North Texas

Thunder Creek

Hamlin

Natural Gas Midstream

Marcellus

Crescent

Strategically Located Assets

Coal and Natural  
Resource Management  
7

8

~ 2/3 of 2009 Adjusted EBITDA

(1)

(1)

Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income and

(2)

Does not include June 2010 acquisition of 10 millions tons of Pittsburgh Seam reserves. With that acquisition, the N. Appalachia Coal & Natural Resource Management

33.0  
603.9  
18.3  
Central  
Appalachia  
5.0  
37.4  
7.5  
San Juan  
Basin  
34.9  
163.9  
4.7  
Illinois Basin  
6.2  
23.4  
3.8  
Northern  
Appalachia  
(2)  
R/P  
Ratio  
(years)  
Proven /  
Probable  
Reserves  
(MM tons)  
2009 Lease  
Production  
(MM tons)  
Region  
24.2 years  
R/P Ratio:  
828.6 MM tons  
Proved / Probable Reserves:  
34.3 MM tons  
2009 Lease Production  
Coal Production & Reserves

9

Coal

Attractive Long Term Fundamentals

EIA

(1)

forecasts that coal:

usage will continue to increase for next

25 years



will continue to be the dominant fuel for  
electric power generation in the U.S.  
will retain its cost advantage as the  
cheapest energy source

(1)  
Annual Energy Outlook 2010 (March 2010), Energy Information Administration (EIA)

Coal

Liquid Fuels

Natural Gas

Other

0

20

40

60

80

100

120

140

U.S. Energy Supply Composition By Primary Source

Fuel Oil

Natural Gas

Steam Coal

0

5

10

15

20

25

Coal

Petroleum

Natural Gas

Nuclear

Other

0

1000

2000

3000

4000

5000

6000

Energy Prices

(2)

U.S. Electrical Generation By Fuel Type

(2)

Prices paid for energy by Electric Generation Sector as reported by EIA

10

Coal Royalty vs. Coal Operator

Coal royalty

not a coal mining operation

Historical Coal Prices vs. Coal Royalty Revenue

Majority of our royalty payments (82%) are based on the higher of a percentage of the gross sales price or a fixed price per ton

Our lessees generally sell their coal under long-term fixed-price contracts (1  
5 years),

which provides cash flow stability

Contracts with our lessees are long-term, with an average life of 10

15 years

No direct exposure to mine operating costs and risks or reclamation costs

Minimal maintenance capital expenditure requirements

Coal Royalty Business -

Stable and Predictable

High

Low

Reclamation Exposure

High

Low

Social Costs

(e.g. benefits, black lung)

High

Medium

Reinvestment Requirements

Variable

High

Cash Flow Stability

Variable

High

Operating Margins

Coal Operator

Coal Royalty

Characteristic

0

20

40

60

80

100

120

140

0

5

10

15

20

25

30

35

40

Quarterly Coal Royalty Revenue

Central Appalachia

Illinois Basin

Consists of a combination of surface and underground mines located in KY, VA and WV  
Lessees customers are primarily electric utilities  
Coal is higher quality, lower sulfur  
Proximity to East Coast ports make these mines an ideal source of exports  
Central Appalachia (73% of Reserves)

Illinois Basin (20% of Reserves)

Comprised of properties in southern Illinois and western Kentucky

Acquired 169 MM tons of reserves in the Illinois Basin beginning in 2005

The installation of scrubbers by Eastern and Midwestern utilities has increased demand for the high sulfur coal in the Illinois Basin

Primary Coal Basins

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Northern Appalachia (3% of Reserves)

San Juan Basin (4% of Reserves)

Northern Appalachia holdings consist of the  
Federal and Upshur properties

Reserves are 100% owned and 98% have been  
leased to operators

Our Lee Ranch property is located in the San  
Juan Basin of northwestern New Mexico and

contains only surface coal mines  
Increased production from 2006 to 2007,  
whereas statewide coal production dropped  
Other Coal Basins

12

13  
Changes  
in  
Coal  
Reserves:  
2002  
  
2009



Coal Production

Reserves

by  
Type

2009

Net  
Royalties  
by  
Region

2009

Reserves  
by  
Region

2009

Coal  
Operations  
492.8  
571.3  
(235.5)

0  
200  
400  
600  
800  
1000

Reserves

12/31/01

Production

2002-2009

Acquired

2003-2009

828.6

0  
5  
10  
15  
20  
25  
30  
35  
40

2004

2005

2006

2007

2008

2009

Central Appalachia  
San Jaun Basin  
Illinois Basin  
Northern Appalachia  
Central  
Appalachia  
69%  
San Juan  
Basin  
14%  
Illinois  
Basin  
11%  
Northern  
Appalachia 6%  
Central  
Appalachia  
73%  
San Juan  
Basin  
4%  
Illinois  
Basin  
20%  
Northern  
Appalachia 3%  
Steam  
89%  
Metallurgical  
11%

Fees charged to lessees for  
use of coal preparation and  
loading facilities  
JV formed in July 2004

Fee-based revenues

Predictable cash flows

Services

5% of Coal & NRM Net Revenue

(1)

Approximately 243,000 acres  
of forestland in Kentucky,  
Virginia and West Virginia

Premium quality hardwood  
primarily used for furniture

Timber

4% of Coal & NRM Net Revenue

(1)

In October 2007, we  
purchased oil and gas  
royalties located on 165,000  
acres in eastern Kentucky  
and southwestern Virginia

Almost all of our oil and  
gas royalty interests are  
associated with leases of  
these properties

Oil & Gas Royalties

2% of Coal & NRM Net Revenue

(1)

Services, Timber & Oil & Gas Royalties

14

Represents 2009 Coal & NRM revenue less Coal Royalty expenses

(1)

Natural Gas  
Midstream  
15

16

~ 1/3 of 2009 Adjusted EBITDA

(1)

(1)

Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to net income and

Natural Gas Midstream Overview

47

80

8  
Crossroads  
8  
20  
AMIs  
with Range Resources  
and a private E&P company  
Marcellus  
18  
N/A  
134  
North  
Texas  
13  
N/A  
78  
Arkoma  
224  
260  
1,681  
Panhandle  
516  
Hamlin  
22  
40  
1,701  
Crescent  
375  
N/A  
588  
Thunder  
Creek  
(25% JV)  
2009  
Volume  
(MMcfd)  
Processing  
Capacity  
(MMcfd)  
Gathering  
Pipeline  
(Miles)  
System  
332 MMcfd  
2009 Avg. System Throughput Vol:  
400 MMcfd  
Natural Gas Processing Capacity:  
4,118 Miles  
Gathering Pipeline:  
Natural Gas Midstream Systems

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Significant organic fee-based growth potential from Crossroads, Thunder Creek and Marcellus project (initial start-up in late 2010 / early 2011)

Target hedging 50-60% of remaining commodity-sensitive volumes over 2 years

Currently, 60% of 2010 and 58% of 2011 price-sensitive volumes are hedged

Additionally, many gas purchase / keep-whole contracts contain a processing fee floor

Volumes by Contract



2004

Volumes by Contract

2009

Since entering the midstream business, we have focused on reducing commodity price risk:

Acquiring fee-based businesses (North Texas and Thunder Creek)

Pursuing green field projects backed by fee-based contracts (Crossroads and Marcellus)

Converting a portion of existing keep-whole contracts to fee-based or POP

Hedged Midstream Business with

Growing Fee-Based Volumes

Fee-

Based

14%

Keep-

Whole

52%

Percent-of-

Proceeds

34%

Fee-Based

19%

Keep-

Whole

28%

Percent-of-

Proceeds

53%

18

Gas Rig Count vs. Natural Gas Production

Lower 48 State On-Shore Gas Production

Oil-to-Natural Gas Price Ratio

Source: Energy Information Administration, Baker Hughes, and Bloomberg

Our assets are well positioned to benefit from increasing activity in emerging resource plays:

Granite Wash

Marcellus Shale

Haynesville Shale / Horizontal Cotton Valley

Attractive processing economics are expected to persist

Well Positioned Asset Base

0  
200  
400  
600  
800  
1000  
1200  
1400  
1600  
1800  
50  
52  
54  
56  
58  
60  
62  
64  
66

Rig Count

Production

0  
2  
4  
6  
8  
10  
12  
14  
16  
18  
20

Shale gas drives future production growth

0.0x  
5.0x  
10.0x  
15.0x  
20.0x  
25.0x  
1990  
1995

2000

2005

2010

2015

2020

2025

2030

2035

Conventional

Shale Gas

Coalbed

Methane

Oil Associated

19

Gathering system in the Anadarko Basin of  
Texas and Oklahoma

Comprised of a number of major gathering  
systems and compressor stations

Beaver / Spearman plants

200 MMcfd of

inlet capacity

Sweetwater plant

Acquired in July

2009,

60 MMcfd of inlet capacity

Approximately 203 producers pursuant to

332 contracts

Positioned to capitalize on the development

of the Granite Wash

Overview

Operating Statistics

Processing Plants

3

Processing Capacity (MMcfd)

260

Gathering System Length (miles)

1,681

Panhandle System

20

Crossroads

Gathering system in Oklahoma

Sooner Trend

Consists of 1,701 miles of pipeline  
and 15 related compressor stations

Crescent

processing  
plant

NGL

recovery plant with capacity of  
40 MMcfd

Wells are generally low-volume and  
long-lived with large NGL quantities

Crescent

Thunder Creek Gas Services

Hamlin

Arkoma

North Texas

Gathering system stretching over  
West Central Texas with the Hamlin  
processing plant located in Fisher  
County, Texas

Consists of 500+ miles of pipeline  
and 8 related compressor stations

Hamlin plant

20 MMcfd capacity

Consists of three separate stand-  
alone gathering systems in  
southeastern Oklahoma's Arkoma  
Basin

Two systems are 100% owned,  
third system is 49% owned

Average 2009 throughput volume  
of 13 MMcfd

Purchased 25% JV interest in  
Thunder Creek from Kinder Morgan  
Energy Partners (April 08) in  
Wyoming's Powder River Basin

Devon Energy owns the other  
75% interest

100% fee-based model

Average 2009 throughput volume of  
375 MMcfd

Located in the southeast portion of  
Harrison County, Texas

Anchored by a long-term  
commitment under a fee-based  
arrangement

80 MMcfd of inlet capacity

Centered around 5 major producers

Positioned for growth from



Haynesville Shale  
Acquired gas gathering and  
transportation assets in the Barnett  
Shale play in the Fort Worth Basin

134 miles of gathering pipeline

Approximately 240,000 acres  
100% fee-based revenues

Potential to increase revenues  
through addition of processing,  
treating and other services  
Natural Gas Midstream  
Other Systems

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AMI with Range Resources in Lycoming, Bradford and Tioga Counties, PA

PVR to provide gathering, compression and related services

Range to initially dedicate over 75,000 acres with ongoing active lease acquisition program within the Area of Mutual Interest ( AMI )

Gathering system will have over 700 MMcfd of throughput capacity

Total capital investment:

Expect \$170  
\$200 million  
between 2010 and 2015  
(approx. \$60 million in  
2010)  
100% fee-based:

Firm reservation charges  
that provide a floor on  
returns

Additional volumetric fees  
based upon delivered  
volumes  
Area Infrastructure and Range Positions  
Tennessee 300 Line

Connects Gulf coast and  
Rockies supply with  
northeastern markets

Capability to move 400 MMcfd  
of Marcellus production  
Transco Leidy Lateral

Connects Leidy storage facility  
with northeastern markets

Capability to move 1.5 Bcfd of  
Marcellus production through  
physical or backhaul transport  
Columbia Gas Transmission / Columbia Gulf  
Marcellus Fairway  
Areas under development  
Texas Eastern Transmission  
Tennessee Gas Pipeline  
Dominion Transmission  
Transcontinental Gas Pipeline  
Marcellus Project Provides Significant Fee-Based Growth

22  
Distributable Cash Flow  
(1)  
vs. Distributions  
Annual Adjusted EBITDA  
(1)  
\$0  
\$40

\$80  
\$120  
\$160  
\$200  
2005  
2006  
2007  
2008  
2009

\$0  
\$35  
\$70  
\$105  
\$140  
\$175  
2005  
2006  
2007  
2008  
2009

Distributions

DCF

(1)

Adjusted EBITDA and Distributable Cash Flows are non-GAAP financial measures. See Appendix for a reconciliations of the

Relatively moderate maintenance capital

expenditure requirements

Target distribution coverage ratio of 1.2x

Target long-term debt / EBITDA ratio of < 3.5x

Growth financed 50% debt / 50% equity

Debt / Adjusted EBITDA

(1)

Average: 2.7x

0.0x  
1.0x  
2.0x  
3.0x  
4.0x  
2005  
2006  
2007  
2008  
2009

Financial Overview

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Conservative Pro Forma Leverage with Strong Liquidity Profile  
Balance Sheet as of June 30, 2010

(1)

Adjusted EBITDA is a non-GAAP financial measure. See Appendix for a reconciliation of Adjusted EBITDA to operating income.

(2)

On August 13, 2010, PVR closed on an amended 5 year credit facility of \$850 million

(3)

Revolver availability includes adjustment for \$1.6 million in letters of credit

Conservative Capitalization

Total Debt

646.5

\$

Partners' Capital

459.4

Total Capitalization

1,105.9

\$

LTM Adjusted EBITDA

(1)

190.6

Debt / Adjusted EBITDA

3.4x

Debt / Capitalization

58%

Revolver Capacity

(2)

850.0

Revolver Availability

(3)

501.9

Diversified, Relatively Low-Risk Asset Base  
Strategically Located Coal Reserves and Midstream Assets  
Stable and Predictable Coal Royalty Business  
Solid Balance Sheet and Attractive Yield  
Stable Cash Flows and Distribution Coverage  
Well  
Positioned  
to



Capitalize  
on  
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Momentum  
&  
Industry  
Trends  
Hedged Midstream Business with Growing Fee-Based Volumes  
Conclusion: Key Investment Highlights  
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Appendix

PVR / PVG Merger

Hedging Strategy

Financial Information

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PVR and PVG will file a joint proxy statement/prospectus and other documents with the SEC in relation to the merger. Investors are urged to read these documents carefully when they become available because they will contain important information regarding PVR, PVG, and the transaction. A definitive joint proxy statement/prospectus will be sent to unitholders of PVR and PVG seeking their approvals as contemplated by the merger agreement. Once available, investors may obtain a free copy of the joint proxy statement/prospectus and other documents containing information about PVR and PVG, without charge, at the SEC website at [www.sec.gov](http://www.sec.gov). Copies of the joint proxy statement/prospectus and the SEC filings that will be incorporated by reference in the joint proxy statement/prospectus may also be obtained free of charge by contacting investor relations at 610-975-8204, or

by accessing [www.pyresource.com](http://www.pyresource.com)  
or [www.pvgpholdings.com](http://www.pvgpholdings.com). PVR, PVG, and the officers and directors of the general partner of  
each partnership may be deemed to be participants in the solicitation of proxies from their security holders. Information about  
these  
entities  
and  
persons  
can  
be  
found  
in  
PVR's  
and  
PVG's  
Annual  
Reports  
on  
Form 10-K  
for  
the  
year  
ended  
December  
31,  
2009.  
Additional  
information  
about  
such  
entities  
and  
persons  
may  
also  
be  
obtained  
from  
the  
joint  
proxy  
statement/prospectus  
when it becomes available.

#### PVR / PVG Merger Legal Notices

Certain statements by PVR and PVG contained herein that are not descriptions of historical facts are forward-looking  
statements by PVR and PVG 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. Words such as may, will, could, should, expect, plan, propose,  
intend, anticipate, believe, estimate, predict, potential, pursue, target, continue, and similar expressions  
intended to identify such forward-looking statements. These forward-looking statements include, without limitation, the  
anticipated benefits and other aspects of the proposed merger, future financial and operating results and expectations and  
intentions with respect to future operations and services, approval of the proposed transaction by PVR and PVG unitholders, the

satisfaction of the closing conditions to the proposed transaction, and the timing of the completion of the proposed transaction. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. Many of the factors that will determine PVR's and PVG's 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. PVR and PVG undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as the result of new information, future events or otherwise. These risks as well as other risks, uncertainties and contingencies are discussed in more detail in PVR's and PVG's joint press release and public periodic filings with the Securities and Exchange Commission (SEC) including PVR's and PVG's Annual Reports on Form 10-K for the year ended December 31, 2009 and most recent Quarterly Reports on Form 10-Q.

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PVR / PVG Merger -  
Transaction Summary

The boards of directors of PVR and PVG have agreed to a merger of the two partnerships in a tax-free, 100% equity exchange

Terms of the merger were approved by the conflicts committees and boards of PVR and

PVG

The merger is subject to approval by a majority of each of PVR's and PVG's unitholders

PVG has agreed to vote its approximate 37.6% interest in PVR units in favor of the merger

PVG unitholders will receive 0.98 PVR limited partnership ( LP ) units in exchange for each PVG LP unit they own

The merger would result in 38.3 million additional PVR units being issued and the cancellation of the approximate 19.6 million PVR LP units currently owned by PVG

Following the merger, the former PVG unitholders will own approximately 54% of PVR's LP units

The merger would result in PVR owning its General Partner and the cancellation of PVG's incentive distribution rights ( IDRs )

The PVR management team will continue in their current roles

PVR's unitholders will elect all of the directors of its general partner's board of directors beginning in 2011

All three of PVG's independent directors are expected to join PVR's board of directors

The transaction is expected to result in dilution of PVR's distributable cash flow per unit of approximately 1.0% in 2011

(a)

Thereafter, the transaction is expected to be accretive as the economic benefits of the merger are realized

(a)

Accretion

/

dilution

calculations

are

based

on

management

assumptions

see

PVR/PVG

merger

presentation

dated

9/22/2010

28  
Current Structure  
Penn Virginia  
Resource Partners, L.P.  
(NYSE: PVR)  
Public  
Unitholders  
32.7 MM



Common Units

60.4% LP interest

Penn Virginia

GP Holdings, L.P.

(NYSE: PVG)

Public

Unitholders

39.1 MM

Common Units

100% LP interest

Penn

Virginia

Resource

GP, LLC

100% ownership

2% GP Interest

and Incentive

Distribution Rights

37.6% LP interest

19.6 MM PVR Common Units

Notes:

1)

Chart displays simplified organizational structure

2)

Units outstanding and ownership interests are rounded approximations

Penn Virginia

Operating Co., LLC

and its subsidiaries

29  
Post-Transaction Structure  
Penn Virginia  
Resource Partners, L.P.  
(NYSE: PVR)  
Public  
Unitholders  
71.0 Million

Common Units

100% LP interest

Penn Virginia

Operating Co., LLC

and its subsidiaries

Penn Virginia

Resource GP, LLC

100% (Indirect)

Non-economic GP interest

Notes:

1)

Chart displays simplified organizational structure

2)

Units outstanding and ownership interests are rounded approximations

30

Expected Merger Benefits

The merger is expected to provide benefits to both PVR and PVG unitholders, including:

Lower Cost of Capital

Elimination of the IDRs

will reduce PVR's cost of capital

Lower cost of capital enhances the cash accretion from investments in internal growth projects and acquisitions

Strengthens PVR's overall competitive position when pursuing growth opportunities

Simplified Structure

Provides a capital structure more easily understood by the investing public

Streamlines governance of PVR

Eliminates the potential for conflicts of interest from dual management roles

Reduces  
G&A  
costs  
associated  
with  
the  
elimination  
of  
one  
publicly  
traded  
entity

Enhanced Investor and Market Profile

Improves transparency for debt and equity investors

Attracts a broader investor base by increasing the public float and trading liquidity of the market for PVR's LP units

Provides PVR's unitholders the right to elect all of the directors of its general partner's board of directors

Based on the exchange ratio and upon closing of the merger, PVG unitholders quarterly cash distributions will increase 18%

31  
Derivative Hedging Strategy

PVR is long NGLs  
and short natural gas

Active hedge strategy to mitigate commodity price risk

Exposed to frac  
spread  
risk through wellhead purchase  
contract and to direct commodity price risk through percent-  
of-proceeds contracts

Current and future hedges

2010 hedges are 60% of current price-sensitive volumes

2011 hedges are 58% of current price-sensitive volumes

Target hedging 50-60% of price sensitive exposure out 2 years

Sensitivity to commodity price changes is expected to  
decrease as a result of increasing fixed-fee volumes  
from the Marcellus Shale, Thunder Creek and  
Crossroads

32  
\$51.2  
30.6  
-  
13.0  
(4.8)  
1.3  
-



(4.6)  
 \$86.7  
 \$104.5  
 58.2  
 31.8  
 (11.4)  
 (38.5)  
 (0.2)  
 -  
 (14.5)  
 \$129.9  
 (\$ in millions)  
 Year Ended December 31,  
 2009  
 2008  
 2007  
 2006  
 2005  
 2004  
 Net Income  
 DD&A  
 Impairments  
 Total derivative losses (gains)  
 Cash settlements of derivatives  
 Equity earnings from jv s, net of distributions.  
 Other  
 Other CAPEX  
 Distributable Cash Flow  
 \$34.3  
 18.6  
 -  
 -  
 -  
 0.6  
 -  
 (0.1)  
 \$53.4  
 \$73.9  
 37.5  
 -  
 13.2  
 (19.4)  
 1.3  
 4.6  
 (9.5)  
 \$101.6  
 \$56.6  
 41.5  
 -  
 50.2

(17.8)

(0.3)

-

(9.8)

\$120.5

\$65.2

70.2

1.5

22.7

3.0

(2.5)

-

(8.4)

\$151.7

PVR -

Historical Distributable Cash Flow Summary

Distributable Cash Flow Reconciliation

33  
(in thousands)  
2009  
2008  
2007  
2006  
2005

Reconciliation of net income to Adjusted EBITDA:

Net income	
\$ 65,215	
\$ 104,500	
\$ 56,623	
\$ 73,928	
\$ 51,161	
Depreciation, depletion and amortization	
70,235	
58,166	
41,512	
37,493	
30,628	
Interest expense	
24,653	
24,672	
17,338	
18,821	
14,054	
EBITDA	
160,103	
187,338	
115,473	
130,242	
95,843	
Impairments	
1,511	
31,801	
-	
-	
-	
Equity earnings, net of distributions received	
(2,537)	
(224)	
(285)	
1,317	
1,269	
Derivative losses (gains)	
22,700	
(11,357)	
50,163	
13,213	
13,036	
Net cash settlements of derivatives	
3,000	
(38,466)	
(17,779)	
(19,436)	
(4,752)	
Adjusted EBITDA	
\$ 184,777	

\$	169,092
\$	147,572
\$	125,336
\$	105,396
Reconciliation of cash flows from operating activities to Adjusted EBITDA:	
Cash flows from operating activities	
\$	159,972
\$	139,176
\$	127,824
\$	107,344
\$	93,712
Changes in operating assets and liabilities	
	5,308
	6,529
	2,243
	(60)
	(635)
Non-cash interest expense	
	(4,391)
	(2,693)
	(678)
	(769)
	(1,735)
Interest expense	
	24,653
	24,672
	17,338
	18,821
	14,054
Equity earnings, net of distributions received	
	2,537
	224
	285
	(1,317)
	(1,269)
Derivative gains (losses)	
	(22,700)
	11,357
	(50,163)
	(13,213)
	(13,036)
Cash settlement on derivatives	
	(3,000)
	38,466
	17,779
	19,436
	4,752
Impairments	
	(1,511)

	(31,801)
	-
	-
	-
Other	(765)
	1,408
	845
	-
	-
EBITDA	
	160,103
	187,338
	115,473
	130,242
	95,843
Impairments	
	1,511
	31,801
	-
	-
	-
Equity earnings, net of distributions received	
	(2,537)
	(224)
	(285)
	1,317
	1,269
Derivative losses (gains)	
	22,700
	(11,357)
	50,163
	13,213
	13,036
Net cash settlements of derivatives	
	3,000
	(38,466)
	(17,779)
	(19,436)
	(4,752)
Adjusted EBITDA	
\$	184,777
\$	169,092
\$	147,572
\$	125,336
\$	105,396
Year Ended December 31,	
PVR -	
Historical Adjusted EBITDA Summary	
Reconciliation of Adjusted EBITDA	