UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

Commission file number: 1-13283

PENN VIRGINIA CORPORATION

(Exact name of registrant as specified in its charter)

Virginia	**23-1184320**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087
(Address of principal executive offices)

Registrant's telephone number, including area code: **(610) 687-8900**

Securities registered pursuant to Section 12(b) of the Act: **None**

Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	**New York Stock Exchange**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 ("Exchange Act"). Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☐	Accelerated filer	☒	Non-accelerated filer	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of common stock held by non-affiliates of the registrant was $313,691,423 as of June 28, 2013 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such stock as quoted on the New York Stock Exchange. For purposes of making this calculation only, the registrant has defined affiliates as including all directors and executive officers of the registrant. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 19, 2014, 65,366,452 shares of common stock of the registrant were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to the registrant's Annual Meeting of Shareholders, to be held on May 7, 2014, are incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2013

Table of Contents

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, or the Exchange Act. 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 and natural gas;
- 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 oil, natural gas liquids 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 gas reserves;
- drilling and operating risks;
- our ability to compete effectively against oil and 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 Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2013.

Additional information concerning these and other factors can be found in our press releases and public periodic filings with the Securities and Exchange Commission. 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.

Glossary of Certain Industry Terminology

The following abbreviations, terms and definitions are commonly used in the oil and gas industry and are used within this Annual Report on Form 10-K.

Bbl	A standard barrel of 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.
Bcf	One billion cubic feet of natural gas.
Bcfe	One billion cubic feet of natural gas equivalent with one barrel of crude oil, condensate or natural gas liquids converted to six thousand cubic feet of natural gas based on the estimated relative energy content.
BOE	One barrel of oil equivalent with six thousand cubic feet of natural gas converted to one barrel of crude oil based on the estimated relative energy content.
BOEPD	Barrels of oil equivalent per day.
Completion	A process of treating a drilled well, including hydraulic fracturing among other stimulation processes, followed by the installation of permanent equipment for the production of oil or gas.
Developed acreage	Lease acreage that is allocated or assignable to producing wells or wells capable of production.
Development well	A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing either oil or gas in sufficient commercial quantities to justify completion of the well.
Exploratory well	A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.
GAAP	Accounting principles generally accepted in the Unites States of America.
Gross acre or well	An acre or well in which a working interest is owned.
HBP	Held by production is a provision in an oil and gas or mineral lease that perpetuates the leaseholder's right to operate the property as long as the property produces a minimum paying quantity of oil or gas.
LLS	Light Louisiana Sweet is a crude oil pricing index reference.
LIBOR	London Interbank Offered Rate.
MBbl	One thousand barrels of oil or other liquid hydrocarbons.
MBOE	One thousand barrels of oil equivalent.
Mcf	One thousand cubic feet of natural gas.
MMBbl	One million barrels of oil or other liquid hydrocarbons.
MMBOE	One million barrels of oil equivalent.
MMBtu	One million British thermal units, a measure of energy content.
MMcf	One million cubic feet of natural gas.
Net acre or well	The number of gross acres or wells multiplied by the owned working interest in such gross acres or wells.
NGL	Natural gas liquid.
NYMEX	New York Mercantile Exchange.
NYSE	New York Stock Exchange.
Operator	The entity responsible for the exploration and/or production of a lease or well.
Play	A geological formation with potential oil and gas reserves.

Productive wells	Wells that are not dry holes.
Possible reserves	Those additional reserves that are less certain to be recovered than probable reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
Probable reserves	Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
Proved reserves	Those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.
Proved developed reserves	Proved reserves that can be expected to be recovered: (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributable to any acreage for which application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same or analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
SEC	The United States Securities and Exchange Commission.
Standardized measure	The present value, discounted at 10% per year, of estimated future cash inflows from the production of proved reserves, computed by applying prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), reduced by estimated future development and production costs, computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year (including the settlement of asset retirement obligations), based on year-end costs and assuming continuation of existing economic conditions, further reduced by estimated future income tax expenses, computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the proved oil and gas reserves, less the tax basis of the properties involved and giving effect to the tax deductions and tax credits and allowances relating to the proved oil and gas reserves.
Revenue interest	An economic interest in production of hydrocarbons from a specified property.
Royalty interest	An interest in the production of a well entitling the owner to a share of production generally free of the costs of exploration, development and production.
Unconventional	Generally refers to hydrocarbon reservoirs that lack discrete boundaries that typically define conventional reservoirs. They are typically referred to as shales, tight sands or coal beds.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves.
WTI	West Texas Intermediate is a crude oil pricing index reference.
Working interest	A cost-bearing interest under an oil and gas lease that gives the holder the right to develop and produce the minerals under the lease.

Part I

Item 1 Business

Unless the context requires otherwise, references to the “Company,” “Penn Virginia,” “we,” “us” or “our” in this Annual Report on Form 10-K refer to Penn Virginia Corporation and its subsidiaries.

Description of Business

Penn Virginia Corporation is an independent oil and gas company engaged in the exploration, development and production of crude oil, NGLs and natural gas in various onshore regions of the United States. We were incorporated in the Commonwealth of Virginia in 1882. Our common stock is publicly traded on the NYSE. Our headquarters and corporate office is located in Radnor, Pennsylvania, and our operations are primarily conducted from our office in Houston, Texas. We also have district operations facilities at various locations in Texas, Oklahoma and Mississippi.

We operate in and report our financial results and disclosures as one segment which is the exploration, development and production of crude oil, NGLs and natural gas. Each of our operating regions has similar economic characteristics and meets the criteria for aggregation as one reporting segment. Prior to June 2010, we were also engaged in the coal and natural resource management and natural gas midstream businesses. We completely disposed of our interests in these businesses in 2010 and have reported them as discontinued operations for any applicable periods included herein.

In mid-2010, we made the decision to shift our investment and production focus away from natural gas and toward higher margin oil and NGLs. Over the course of three years, we have succeeded in transforming ourselves from a predominantly natural gas producer to a predominantly oil and NGL producer. Since 2010, we have increased our acreage position in the Eagle Ford Shale from approximately 7,500 net acres to approximately 78,000 net acres through the end of 2013 and, in 2013, crude oil and NGLs accounted for approximately 65 percent of total production and 88 percent of product revenues as compared to 15 percent of production and 26 percent of product revenues in 2009. Also in 2013, we spent $494 million, or 97 percent, of our capital program on Eagle Ford Shale operations. Our Eagle Ford Shale properties are located principally in the “volatile oil window” of the play, and we believe they provide us with an approximate ten-year drilling inventory based on our current pace of drilling and results.

To accomplish our natural gas-to-oil transformation, we made several significant oil and NGL acquisitions in the Eagle Ford Shale, and disposed of a significant portion of our natural gas and other non-core assets. We completed our initial acquisition in 2010 when we acquired 6,800 net undeveloped Eagle Ford Shale acres in Gonzales County, Texas. In 2013, we made a significant acquisition, or our 2013 EF Acquisition, of 40,600 gross (17,700 net) acres in Gonzales County and Lavaca County, Texas, including producing properties, primarily contiguous to our initial acreage. In addition, since 2010, we have acquired through a combination of leasing and earning through drilling approximately 67,800 gross (53,500 net) Eagle Ford Shale acres in Gonzales and Lavaca Counties contiguous to or near our previously acquired Eagle Ford Shale acreage.

Since 2010, we have disposed of an aggregate of approximately $161 million of natural gas assets located in Appalachia, the Arkoma Basin and the Gulf Coast regions of South Texas and Louisiana. In addition, in January 2014, we sold our South Texas natural gas gathering assets for $100 million, or approximately $94 million net to our working interest, and we recently initiated a process to sell our Granite Wash and Selma Chalk assets, which include proved reserves of approximately 26 MMBOE and production of approximately 4,200 BOEPD.

Current Operations

Our current operations consist of drilling unconventional horizontal development wells primarily concentrated in the Eagle Ford Shale in South Texas. We also have operations in the Granite Wash in the Mid-Continent (primarily Oklahoma), the Haynesville Shale and Cotton Valley in East Texas and the Selma Chalk in Mississippi. We retain undeveloped acreage in the Marcellus Shale in Pennsylvania, but our Appalachian operations are limited to three operated wells.

In 2013, our production totaled 6.8 MMBOE. Our total production was comprised of crude oil (50 percent), NGLs (15 percent) and natural gas (35 percent). Our total product revenues of $430.7 million were derived from sales of crude oil (81 percent), NGLs (seven percent) and natural gas (12 percent). Sixty percent of our production was derived from South Texas, primarily the Eagle Ford Shale. The remaining production was derived from the Haynesville Shale and Cotton Valley in East Texas (15 percent), the Granite Wash in the Mid-Continent (14 percent), the Selma Chalk in Mississippi (11 percent) and the Marcellus Shale in Appalachia (less than one percent).

As of December 31, 2013, our proved reserves were approximately 136 MMBOE, of which 40 percent were proved developed reserves and 61 percent were oil and NGLs. Our proved reserves and primary development plays are located in South Texas, East Texas, the Mid-Continent and Mississippi, which comprised 56 percent, 26 percent, eight percent and 10 percent of our total proved reserves, respectively, as of December 31, 2013.

In 2013, we drilled 59 gross (34.6 net) wells, of which 58 (34.1 net) were productive and one (0.5 net) was under evaluation as of December 31, 2013. Included in the total were 57 gross (34.1 net) wells drilled in the Eagle Ford Shale. We had 16 gross (11.5 net) wells in progress as of December 31, 2013 including three gross (2.8 net) wells completing, eight gross (5.0 net) wells waiting on completion and five gross (3.7 net) wells being drilled. As of December 31, 2013, we had 1,213 gross (969.2 net) productive wells, approximately 96 percent of which we operate, and owned approximately 280,400 gross (191,200 net) acres of leasehold and royalty interests, approximately 42 percent of which were undeveloped. For a more detailed discussion of our production, reserves, drilling activities, wells and acreage, see Item 2, "Properties."

In 2013, our capital expenditures, excluding our 2013 EF Acquisition, were approximately $510 million, of which approximately $405 million, or 80 percent, was related to development drilling, approximately $69 million, or 13 percent, was related to leasehold acquisitions and related title work and approximately $13 million, or three percent, was related to exploratory drilling. The remaining $23 million, or four percent, was related to pipelines, gathering assets, facilities and corporate projects.

For additional financial information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Developments" and our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplementary Data."

Business Strategy

We intend to pursue the following business strategies:

- *Executing our drilling program and further expanding in the Eagle Ford Shale*. We anticipate operating up to six rigs for our 2014 drilling program, but will assess, on a regular basis, the opportunity to increase the rig count further and accelerate the value of our undrilled locations. We are continuing efforts to lower our completion costs and improve results through the increased use of multi-well pads and more effective fracturing techniques and stimulation referred to as "zipper fracs." We currently own approximately 80,000 net acres in the Eagle Ford Shale, and we plan to further increase our acreage position in proximity to our existing holdings. As of February 19, 2014, our lease position provides us with a significant number of drilling locations, or the equivalent of an approximate ten-year inventory of drilling sites.
- *Improving our liquidity and financial position.* We are pursuing a goal of continuing to strengthen our balance sheet over the next three years. In furtherance of this goal, in January 2014, we sold our South Texas natural gas gathering assets. We have also initiated a process to sell our Selma Chalk and Granite Wash assets, consisting of proved reserves of approximately 26 MMBOE and production of approximately 4,200 BOEPD. We anticipate these proceeds would substantially fund our projected capital program outspend for 2014. Through these actions, we anticipate lowering our debt to EBITDAX ratio, a non-GAAP measure defined in our revolving credit agreement, or Revolver. Our goal is to maintain a level of financial liquidity (cash on hand plus availability under the Revolver) of a minimum of $150 million, and in the longer term, maintain a debt to EBITDAX ratio of less than 3.0 times.
- *Managing risk exposure through an active hedging program*. We actively manage our exposure to commodity price fluctuations by hedging the commodity price risk for our expected production. The level of our hedging activity and duration of the instruments employed depend upon our cash flows at risk, available hedge prices and our operating strategy. We have hedged approximately 70 percent of our estimated crude oil production for the first half of 2014 and approximately 65 percent for the second half of 2014 at a weighted-average floor price of $93.55 per barrel. In addition, we have hedged approximately 40 percent of our estimated natural gas production through the third quarter of 2014 at a weighted-average floor price of $4.13 per MMBtu and approximately 15 percent for the 2014 - 2015 winter at a weighted-average floor price of $4.50 per MMBtu.
- *Retain long-term optionality of our core natural gas assets.* We maintain substantial natural gas properties in the Haynesville Shale and Cotton Valley in East Texas, which are largely HBP. At this time, we plan to retain these assets, which provide us with the option to increase development in these regions.
- *Generating new exploration opportunities.* We are actively seeking new exploration opportunities with a goal of early entry into emerging plays at modest lease acquisition cost. Potential opportunities that we are considering include resource and unconventional play types with a horizontal drilling application.

Contractual Arrangements

In the ordinary course of operating our business, we enter into a number of contracts for goods and services. The following is a summary of our most significant contractual arrangements.

Marketing. We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts. Our crude oil sales are generally committed at the wellhead and are priced based on the NYMEX quoted price for WTI crude oil plus any differential for LLS less deductions for transportation and quality. Our NGLs are sold to interstate and midstream pipelines with pricing based on the Mont Belvieu, Texas or Conway, Kansas indices less deductions for transportation and fractionation and a marketing fee. Our natural gas production is also sold to interstate and midstream pipelines with pricing based on the NYMEX quoted price for Henry Hub natural gas adjusted for any basis differential or as a percentage of certain regional reference prices.

Drilling and Completion. We have agreements to purchase oil and gas well drilling and well completion services, including hydraulic fracturing services. Generally, these agreements are on a month-to-month basis, but certain agreements extend for terms beyond one year. These agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their original terms. We also purchase a substantial volume of well materials, including tubular products as well as proppant and other chemicals used in the well fracturing and stimulation process. Some of these products are provided for in our agreements for well completion services and in other cases we source such materials from different vendors.

Gathering and Compression. Concurrent with the recent sale of our South Texas natural gas gathering assets, we entered into a an agreement that will provide gathering and compression services for our natural gas production in the South Texas region for a term of 25 years.

Transportation. We have entered into contracts that provide firm transportation capacity rights for specified volumes of natural gas per day on various pipeline systems for terms ranging from one to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Commodity Derivatives. We generally utilize collar, swap and swaption derivative contracts, among others, to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

Major Customers and Seasonality

We sell a significant portion of our oil and gas production to a relatively small number of customers. For the year ended December 31, 2013, approximately 42 percent of our consolidated product revenues were attributable to three customers: Sunoco Refining and Marketing, Inc.; Gulfmark Energy Inc.; and Enterprise Crude Oil LLC. Our sales of oil and gas are dependent upon the number of producing wells that we are operating and, therefore, are not seasonal by nature. We do not believe that the pricing of our oil and NGL production is subject to any meaningful seasonal effects. Historically, the pricing of natural gas is seasonal with higher pricing typically occurring in the winter months.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies that are large, well-established and have greater financial and operational resources than we do, which may adversely affect our ability to compete or grow our business. Many such companies not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also carry on refining operations, electricity generation and the marketing of refined products. Competition is particularly intense in the acquisition of prospective oil and gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We compete with other oil and gas companies to secure drilling rigs and other equipment necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. We also compete with substantially larger oil and gas companies in the marketing and sale of oil and gas, and the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws that govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2013, we have recorded asset retirement obligations of $6.4 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations and cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing, could have the potential to adversely affect our financial condition, results of operations and cash flows.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the "Superfund" law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible parties" may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of oil and gas for a number of years. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and clean up of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future, and therefore be subject to RCRA.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term "waters of the United States" has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA subjects owners of facilities to strict, joint and several liability for all containment and clean up costs, and certain other damages arising from a spill.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, governs the discharge of certain pollutants into waters of the United States. The discharge of pollutants into regulated waters without a permit issued by the EPA or the state is prohibited. The Clean Water Act also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. Notably, in Pennsylvania, wastewater from the hydraulic fracturing process can no longer be sent to publicly owned treatment works directly. New wastewater discharges must be treated at a centralized waste treatment facility and comply with certain Total Dissolved Solids standards prior to being discharged to publicly owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. The EPA is currently developing analogous pretreatment standards on the federal level.

Safe Drinking Water Act. The Safe Drinking Water Act, or the SDWA, and the Underground Injection Control Program promulgated under the SDWA, establish the requirements for salt water disposal well activities and prohibit the migration of fluid containing contaminants into underground sources of drinking water. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays like the Eagle Ford Shale, Granite Wash, Haynesville Shale and the Marcellus Shale formations. The Fracturing Responsibility and Awareness of Chemicals Act that was introduced in both the 111th and 112th Congresses would subject hydraulic fracturing operations to federal regulation under the SDWA and require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse impacts of hydraulic fracturing on drinking water and ground water. The EPA released a progress report on its study on December 21, 2012 and expects to release a final draft for public comment and peer review in 2014.

Additionally, certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Mississippi, Oklahoma, Pennsylvania and Texas have implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations. For example, Pennsylvania has instituted a moratorium on leasing state forest land for gas drilling, and municipalities in New York have banned or limited hydraulic fracturing within their borders. Additionally, the New York State Department of Environmental Conservation, or NYDEC, has ceased issuing drilling permits for horizontal drilling under the General Environmental Impact Statement, pending completion of the Supplemental General Environmental Impact Statement, or SGEIS, that takes into account the impacts of high volume hydraulic fracturing. However, the NYDEC has stated that it will consider individual, site-specific environmental reviews for any entity that wishes to proceed with a permit application as long as that review is of similar scope and depth as the SGEIS. The most recent draft of the SGEIS was released in September 2011 but final regulations have not yet been issued.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. Pennsylvania and West Virginia have issued setback regulations for wells. Colorado recently enacted new setback restrictions as well as requirements to conduct sampling on water wells before and after drilling. In addition, states such as Texas and Pennsylvania have water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or operating wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

A recent decision by the Pennsylvania Supreme Court may empower local governments to limit and/or regulate hydraulic fracturing, which could complicate and delay hydraulic fracturing activity. In February 2012, Pennsylvania passed Act 13, which, among other things, provided for new well fees assessed and collected on unconventional wells, substantial revisions to environmental protections for both surface and subsurface activities, and prevented local zoning rules from imposing burdens on oil and gas activities beyond those required by the state. However, in December 2013, the court struck down portions of Act 13, including deeming the statewide preemption of local zoning rules and the setback requirement waiver provisions unconstitutional. The Commonwealth has sought reconsideration and a remand. If this decision is not modified by subsequent rulings and the statute is not amended to address the decision, the net affect may be to subject hydraulic fracturing activities to local limitations and potentially duplicative and inconsistent regulations.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements. In 1990, the U.S. Congress adopted amendments to the CAA containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Further, stricter requirements could negatively impact our production and operations. For example, the Texas Commission on Environmental Quality and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. These initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state and federal levels.

Additionally, on April 17, 2012, the EPA issued new rules subjecting all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. The new rules regulate emissions from several types of emission sources that have never before been subject to federal standards, and also include NSPS standards for completion of hydraulically fractured gas wells. The standards apply to newly drilled and fractured wells, as well as existing wells that are refractured. The NESHAPS regulations apply to certain major sources of hazardous air pollutants not previously subject to Maximum Achievable Control Technology, or MACT, standards. In September 2013, the EPA published updates to the 2012 performance standards, setting the compliance deadline for tanks based upon when they were put into use. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions from our compressors at initial startup or by the applicable compliance deadline. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. We are currently researching the effect these new rules will have on our business, but generally expect them to add to the cost and expense of our operations.

There have been recent claims asserted that individual wells and other facilities should be "aggregated" together and their collective emissions considered in determining whether major source permitting requirements apply under the CAA. If we were required to aggregate individual wells and other facilities, it could bring us within the ambit of the Title V permitting program, and we could be considered a major source for MACT applicability. For example, though the Sixth Circuit recently vacated an EPA determination to aggregate natural gas wells and a sweetening plant in *Summit Petroleum Corp. v. EPA et al.*, the EPA released a December 21, 2012 memorandum stating that although the EPA will follow the court's interpretation when considering aggregation in the Sixth Circuit, it will continue to follow its current practice of considering interrelatedness in other jurisdictions. In addition, in *Citizens for Pennsylvania's Future v. Ultra Resources, Inc.*, a case challenging a decision not to aggregate certain facilities in Pennsylvania, the court allowed the case to move forward by denying defendant's motion to dismiss, even though the plaintiff had not exhausted review procedures with the administrative agency.

Greenhouse Gas Emissions. Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of greenhouse gas, or GHG, emissions. On June 28, 2010, the EPA issued the "Final Mandatory Reporting of Greenhouse Gases" Rule, or the Reporting Rule, requiring all stationary sources that emit more than 25,000 tons of GHGs per year to collect and report to the EPA data regarding such emissions. The Reporting Rule establishes a new comprehensive scheme, which began in 2011, requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. On November 9, 2010, the EPA issued final rules applying these regulations to the oil and gas source category, including oil and gas production, natural gas processing, transmission, distribution and storage facilities (Subpart W). This action does not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits.

In addition, in 2009, the EPA issued a final rule known as the EPA's Endangerment Finding finding that current and projected concentrations of six key GHGs in the atmosphere threaten public health and the environment, as well as the welfare of current and future generations. Legal challenges to these findings have been asserted, and the U.S. Congress is considering legislation to delay or repeal the EPA's actions, but we cannot predict the outcome of this litigation or these efforts. The EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. These rules were subject to judicial challenge, but on June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit rejected challenges to the tailoring rule and other EPA rules relating to the regulation of GHGs under the CAA.

Starting July 1, 2011, the EPA required facilities that must already obtain New Source Review permits for other pollutants to include GHGs in their permits for new construction projects that emit at least 100,000 tons per year of GHGs and existing facilities that increase their emissions by at least 75,000 tons per year. On March 27, 2012, the EPA issued its proposed NSPS for carbon dioxide emissions standard from new and modified power plants and held public hearings on the rule in May 2012 and accepted written comments until June 25, 2012. In its June 2013 Climate Action Plan, the Obama Administration announced its intent to issue regulations under Section 111(b) and Section 111(d) of the CAA to set NSPS for both new and existing power plants by June 2015. In January 2014, the EPA formally published re-proposed GHG NSPS for new and modified electric generating units ("EGUs"). The Climate Action Plan also directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas agency. In addition, in October 2013, the U.S. Supreme Court granted certiorari to hear arguments related to a combination of several petitions challenging the EPA's approach to CO_2 regulation. As a result of this continued regulatory focus, future federal GHG regulations of the oil and gas industry remain a possibility. Also, many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities. While it is not possible to predict how any regulations to restrict GHG emissions may come into force, these and other legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require us to incur additional operating costs or curtail oil and gas operations in certain areas and could also adversely affect demand for the oil and gas we sell.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species.

Employees and Labor Relations

We had a total of 144 employees as of December 31, 2013. We consider our current employee relations to be favorable. We and our employees are not subject to any collective bargaining agreements.

Available Information

Our internet address is http://www.pennvirginia.com. We make available free of charge on or through our website our Corporate Governance Principles, Code of Business Conduct and Ethics, Executive and Financial Officer Code of Ethics, Audit Committee Charter, Compensation and Benefits Committee Charter and Nominating and Governance Committee Charter, and we will provide copies of such documents to any shareholder who so requests. We also make available free of charge on or through our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A Risk Factors

Our business and operations are subject to a number of risks and uncertainties as described below. However, the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, financial condition, results of operations and cash flows. If any of the following risks actually occur, our business, financial condition, results of operations and cash flows could suffer.

Crude oil, NGL and natural gas prices are volatile, and a substantial or extended decline in prices would hurt our profitability and financial condition.

Our revenues, operating results, cash flows, profitability, future rate of growth and the carrying value of our oil and gas properties depend heavily on prevailing market prices for crude oil, NGLs and natural gas. Historically, crude oil, NGL and natural gas prices have been volatile, and they are likely to continue to be volatile. Even relatively modest drops in prices can affect significantly our financial results and impede our growth. Wide fluctuations in crude oil, NGLs and natural gas prices may result from relatively minor changes in the supply of and demand for oil and gas, market demand and other factors that are beyond our control, including:

- domestic and foreign supplies of crude oil, NGLs and natural gas;
- domestic and foreign consumer demand for crude oil, NGLs and natural gas;
- political and economic conditions in oil or gas producing regions;
- overall domestic and foreign economic conditions;
- prices and availability of, and demand for, alternative fuels;
- the availability of gathering, processing and transportation facilities;
- weather conditions; and
- domestic and foreign governmental regulation.

Many of our projections and estimates are based on assumptions as to the future prices of crude oil, NGLs and natural gas. These price assumptions are used for planning purposes. We expect our assumptions will change over time and that actual prices in the future will likely differ from our estimates. Any substantial or extended decline in the actual prices of crude oil, NGLs or natural gas would have a material adverse effect on our business, financial position, results of operations and cash flows, borrowing capacity and possible asset impairment), the quantities of oil and gas reserves that we can economically produce, the quantity of estimated proved reserves that may be attributed to our properties and our ability to fund our capital program.

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operating activities. We have historically succeeded in substantially replacing reserves primarily through exploration and development and, to a lesser extent, acquisitions. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves and production from such activities at acceptable costs. Lower prices also decrease our cash flows from operating activities and may cause us to reduce capital expenditures.

The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operating activities are reduced and external sources of capital are limited. In addition, exploration and development activities involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating acquisition opportunities. However, competition for oil and gas properties is intense and many of our competitors have financial and other resources substantially greater than those available to us. In the event we are successful in completing an acquisition, we cannot ensure that such acquisition will consist of properties that contain economically recoverable reserves or that such acquisition will be profitably integrated into our operations.

We may not be able to fund our planned capital expenditures.

We make, and will continue to make, substantial capital expenditures to find, acquire, develop and produce oil and gas reserves. In 2014, we anticipate making capital expenditures, excluding acquisitions, of up to approximately $640 million.

If crude oil or NGL prices decrease, natural gas prices fail to recover or we encounter operating difficulties that result in our cash flow from operations being less than expected, we may have to reduce our capital expenditures unless we have sufficient borrowing capacity under the Revolver.

Future cash flows and the availability of financing will also be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and prices of crude oil, NGLs and natural gas.

If our revenues were to decrease due to lower crude oil, NGL and natural gas prices, decreased production or other reasons, and if we could not obtain capital through the Revolver, or otherwise on acceptable terms, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

We have a significant amount of indebtedness and our ability to service our indebtedness depends on certain financial, business and other factors, many of which are beyond our control.

As of December 31, 2013, we had an aggregate of approximately $1.3 billion of debt outstanding and would have been able to incur an additional $257.3 million (net of $2.7 million of letters of credit) under the Revolver. We may incur additional indebtedness in the future. Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;
- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure; and
- depending on the levels of our outstanding debt, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited.

Our ability to make scheduled payments of principal and interest on our indebtedness or to refinance our debt obligations depends on our future financial condition and operating performance, which will be subject to general economic conditions and to certain financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to generate sufficient cash flows from operating activities in the future to service our debt, we may be forced, among other things, to:

- seek additional financing in the debt or equity markets;
- refinance or restructure all or a portion of our indebtedness;
- sell selected assets;
- reduce or delay planned capital expenditures; or
- reduce or delay planned operating expenditures.

Such measures might not be successful and might not enable us to service our debt. In addition, any such financing, refinancing or sale of assets might not be available on economically favorable terms.

The borrowing base under the Revolver may be reduced in the future if commodity prices decline.

The borrowing base under the Revolver is $425 million as of December 31, 2013. Our borrowing base is redetermined twice each year and is scheduled to be redetermined during April 2014. If crude oil, NGL or natural gas prices decline, the borrowing base under the Revolver may be reduced. As a result, we may be unable to obtain funding under the Revolver. If funding is not available when or in the amounts needed, or is available only on unfavorable terms, it might adversely affect our development plan as currently anticipated and our ability to make new acquisitions, each of which could have a material adverse effect on our production, financial condition, results of operations and cash flows.

The Revolver and our other debt instruments have restrictive covenants that could limit our financial flexibility.

The Revolver and the indentures related to our outstanding senior notes contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Revolver is subject to compliance with certain financial covenants, including leverage and interest coverage ratios. The Revolver includes other restrictions that, among other things, limit our ability to incur indebtedness; grant liens; engage in mergers, consolidations and liquidations; make asset dispositions, restricted payments and investments; enter into transactions with affiliates; and amend, modify or prepay certain indebtedness. The indentures related to our outstanding senior notes contain limitations on our ability to effect mergers and change of control events, as well as other limitations, including:

- limitations on the declaration and payment of dividends or other restricted payments;
- limitations on incurring additional indebtedness or issuing preferred stock;
- limitations on the creation or existence of certain liens;
- limitations on incurring restrictions on the ability of certain of our subsidiaries to pay dividends or other payments;
- limitations on transactions with affiliates; and
- limitations on the sale of assets.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our debts. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or gas reserves will be found. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, crews, equipment and materials;
- shortages in experienced labor;
- failure to or delays in securing necessary regulatory approvals and permits, including delays due to potential hydraulic fracturing regulations;
- fires, explosions, blow-outs and surface cratering; and
- adverse weather conditions.

The prevailing prices of crude oil, NGLs and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. The availability of drilling rigs and equipment can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. In addition, limitations on the use of hydraulic fracturing could have an adverse effect on our ability to develop and produce oil and gas from new wells, which would reduce our rate of return on these wells and our cash flows. Drilling activities can result in dry wells or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our business, financial condition, results of operations and cash flows. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

We are exposed to the credit risk of our customers, and nonpayment or nonperformance by these parties would reduce our cash flows.

We are subject to risk from loss resulting from our customers' nonperformance or nonpayment. We depend on a limited number of customers for a significant portion of revenues. In 2013, approximately 42 percent of our total consolidated product revenues resulted from three of our customers. Any nonpayment or nonperformance by our customers would reduce our cash flows.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one party. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the possibility of an economic downturn and the volatility in commodity prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established than we, are not able to fulfill their joint activity obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems may lead our partners to attempt to delay the pace of drilling or project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial condition, results of operations and cash flows.

Our business involves many operating risks, including hydraulic fracturing, that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for and the production and transportation of oil and gas, including well stimulation and completion activities such as hydraulic fracturing. These operating risks include:

- fires, explosions, blowouts, cratering and casing collapses;
- formations with abnormal pressures;
- pipeline ruptures or spills;
- uncontrollable flows of oil, natural gas or well fluids;
- migration of fracturing fluids into surrounding groundwater;
- spills or releases of fracturing fluids including from trucks sometimes used to deliver these materials;
- spills or releases of brine or other produced water that may go off-site;
- subsurface conditions that prevent us from (i) stimulating the planned number of stages, (ii) accessing the entirety of the wellbore with our tools during completion or (iii) removing all fracturing materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases;
- personal injuries and death; and
- natural disasters.

Any of these risks could result in substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. In addition, under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

If we experience any of these problems with well stimulation and completion activities, such as hydraulic fracturing, our ability to explore for and produce oil or natural gas may be adversely affected. We could incur substantial losses or otherwise fail to realize reserves in particular formations as a result of:

- the need to shut down, abandon and relocate drilling operations;
- the need to sample, test and monitor drinking water in particular areas and to provide filtration or other drinking water supplies to users of water supplies that may have been impacted or threatened by potential contamination from fracturing fluids;
- the need to modify drill sites to ensure there are no spills or releases off-site and to investigate and/or remediate any spills or releases that might have occurred; or
- suspension of our operations.

In accordance with industry practice, we maintain insurance at a level that balances the cost of insurance with our assessment of the risk and our ability to achieve a reasonable rate of return on our investments. We cannot assure you that our insurance will be adequate to cover losses or liabilities or that we can purchase insurance against all possible losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our business depends on gathering, processing and transportation facilities owned by others.

We deliver substantially all of our oil and gas production through pipelines that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines, as well as gathering systems and processing facilities. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather, process and market our oil and gas.

Estimates of oil and gas reserves are not precise.

This Annual Report on Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the estimated quantities and present value of our reserves.

Actual future production, crude oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil, NGL and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2013, approximately 60 percent of our estimated proved reserves were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is based on volumetric calculations and adjacent reserve performance data. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Production revenues from proved developed non-producing reserves will not be realized until some time in the future. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with these reserves in accordance with industry standards, these estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

Moreover, the reserve estimation standards provide that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These standards may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not develop those reserves within the required five-year time frame or cannot demonstrate that we could do so. We removed approximately 20 MMBOE of proved undeveloped reserves in 2013 as a result of the five-year limitation.

You should not assume that the present value of estimated future net cash flows (standardized measure) referred to herein is the current fair value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual current and future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. As a result, net present value estimates using actual prices and costs may be significantly less than the SEC estimate that is provided herein. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for us.

We may record impairment losses on our oil and gas properties.

Quantities of proved reserves are estimated based on economic conditions in existence in the period of assessment. Lower crude oil, NGL and natural gas prices may have the impact of shortening the economic lives on certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves occur, it will have the effect of increasing the rates of depreciation, depletion and amortization, or DD&A, on the affected properties, which would decrease earnings or result in losses through higher DD&A expense. The revisions may also be sufficient enough to cause impairment losses on certain properties that would result in a further non-cash charge to reported earnings.

GAAP requires that the carrying value of oil and gas properties be reviewed on a periodic basis for possible impairment. An impairment charge is recognized when the carrying value of oil and gas properties is greater than the undiscounted future net cash flows attributable to the property. In addition to revisions to reserves and the impact of lower commodity prices, impairments may occur due to increases in estimated operating and development costs and other factors. During the past several years, we have been required to impair certain of our oil and gas properties and related assets. If crude oil, NGL and natural gas prices decline or we drill uneconomic wells, it is reasonably possible that we will have to record a significant impairment in the future. While an impairment charge reflects our ability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

We have limited control over the activities on properties we do not operate.

In 2013, other companies operated approximately 11 percent of our net production. Our success in properties operated by others will depend upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund for their operation. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could have a material adverse effect on the realization of our targeted returns or lead to unexpected future costs.

Our property acquisitions carry significant risks.

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. In the event we do complete an acquisition, its success will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future crude oil, NGL and natural gas prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results, and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive federal, state and local laws and regulations, including complex environmental laws. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations, inability to obtain necessary regulatory approvals or a failure to comply with existing legal requirements may harm our business, results of operations or financial condition. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs and land owners may file claims for alternative water supplies, property damage or bodily injury. Laws and regulations protecting the environment have become more stringent in recent years, and may, in some circumstances, result in liability for environmental damage regardless of negligence or fault. In addition, pollution and similar environmental risks generally are not fully insurable. These liabilities and costs could have a material adverse effect on our business, financial condition, results of operations and cash flows. See Item 1, "Business — Government Regulation and Environmental Matters."

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The practice of hydraulic fracturing has come under increased scrutiny by the environmental community. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into prospective rock formations to stimulate oil and gas production. We use this completion technique on all of our wells. The EPA is studying the potential environmental impacts of hydraulic fracturing and is expected to release a draft report in 2014. The EPA is also expected to announce a proposed rulemaking regarding chemical substances and mixtures used in oil and gas exploration and production and propose new pretreatment standards for wastewater from hydraulically fractured wells in 2014. In addition, some states and local governments have enacted legislation or adopted regulations, and the U.S. Congress and other states are considering enacting legislation or adopting regulations, that could impose more stringent permitting, disclosure, well construction and water use requirements on hydraulic fracturing operations. Individually or collectively, such new legislation or regulation could result in increased compliance and operating costs, delays or additional operating restrictions. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Derivative transactions may limit our potential gains and involve other risks.

In order to manage our exposure to price risks in the sale of our crude oil, NGLs and natural gas, we periodically enter into commodity price hedging arrangements with respect to a portion of our expected production. Our hedges are limited in duration, usually for periods of two years or less. While intended to reduce the effects of volatile crude oil, NGL and natural gas prices, such transactions may limit our potential gains if crude oil, NGL or natural gas prices were to rise over the price established by the hedging arrangements. In trying to maintain an appropriate balance, we may end up hedging too much or too little, depending upon how crude oil, NGL or natural gas prices fluctuate in the future.

In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts crude oil, NGL or natural gas prices.

In addition, derivative instruments involve basis risk. Basis risk in a derivative contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective. For example, a NYMEX index used for hedging certain volumes of production may have more or less variability than the regional price index used for the sale of that production.

Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

Our ability to utilize U.S. net operating loss. or NOL, carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended, or the Code. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. As of December 31, 2013, we do not believe that an ownership change has occurred; however, to the extent an ownership change has occurred or were to occur in the future, it is possible that the limitations imposed on our ability to use pre-ownership change losses could cause a significant net increase in our U.S. federal income tax liability and could cause U.S. federal income taxes to be paid earlier than they otherwise would be paid if such limitations were not in effect.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

President Obama’s budget proposal for fiscal year 2013 recommended the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, the repeal of the percentage depletion allowance for oil and gas properties, the elimination of current deductions for intangible drilling and development costs, the elimination of the deduction for United States production activities for oil and gas production, and an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could have a material adverse effect on us.

A cyber incident could result in theft of confidential information, data corruption or operational disruption.

The oil and gas industry is dependent on digital technologies to conduct certain exploration, development and production activities. Software programs are used for, among other things, reserve estimates, seismic interpretation, modeling and compliance reporting. In addition, the use of mobile communication is widespread. Increasingly, we must protect our business against potential cyber incidents including attacks.

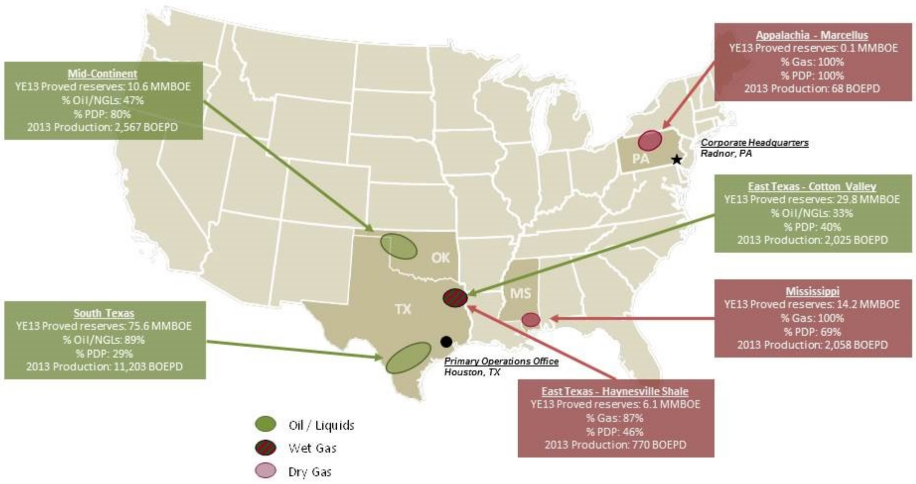
If our systems for protecting against cyber incidents prove not to be sufficient, we could be adversely affected by unauthorized access to our digital systems which could result in theft of confidential information, data corruption or operational disruption. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Item 1B Unresolved Staff Comments

We have received no written SEC staff comments regarding our periodic or current reports under the Exchange Act that were issued 180 days or more preceding the end of our 2013 fiscal year and remain unresolved.

Item 2 Properties

The following map shows the general locations of our oil and gas assets as of December 31, 2013:



Facilities

All of our office facilities are leased with the exception of our district operations facilities in Scottsville, Texas. We believe that our facilities are adequate for our current needs.

Title to Oil and Gas Properties

Prior to completing an acquisition of producing oil and gas assets, we review title opinions on all material leases. However, as is customary in the oil and gas industry, we make only a cursory review of title to farmout acreage and when we acquire undeveloped oil and gas leases. Prior to the commencement of drilling operations, a thorough title examination is conducted. To the extent the title examination reflects defects, we cure such title defects. If we are unable to cure any title defect of a nature such that it would not be prudent to commence drilling operations on a property, we could suffer a loss of our investment in the property. Our oil and gas properties are subject to customary royalty interests, liens for debt obligations, current taxes and other burdens that we believe do not materially interfere with the use or materially affect the value of such properties. We believe that we have satisfactory title to all of our properties and the associated oil and gas in accordance with standards generally accepted in the oil and gas industry.

Summary of Oil and Gas Reserves

Proved Reserves

The following tables summarize certain information regarding our estimated proved reserves as of December 31 for each of the years presented:

	Crude Oil	NGLs	Natural Gas	Oil Equivalents	Standardized Measure	Price Measurement Used [1]		
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$/Bbl of Oil	$/Bbl of NGLs	$/MMBtu
2013								
Developed								
Producing	19.0	7.5	146.5	50.9	$ 701.7			
Non-producing	0.3	1.0	16.7	4.1	7.3			
	19.3	8.5	163.2	55.0	709.0			
Undeveloped	41.4	13.4	158.9	81.3	554.8			
	60.7	21.9	322.1	136.3	$ 1,263.8	$ 103.11	$ 31.10	$ 3.47
2012								
Developed								
Producing	10.2	7.0	152.0	42.5	$ 408.5			
Non-producing	0.3	1.2	17.4	4.5	43.0			
	10.5	8.3	169.4	47.0	451.5			
Undeveloped	14.4	12.4	238.1	66.5	46.4			
	24.9	20.7	407.5	113.5	$ 497.9	$ 102.24	$ 39.48	$ 2.47
2011								
Developed								
Producing	6.4	8.1	308.1	65.8	$ 552.8			
Non-producing	0.7	1.3	22.4	5.8	49.0			
	7.1	9.4	330.5	71.6	601.8			
Undeveloped	7.0	12.1	339.4	75.6	52.7			
	14.1	21.5	669.9	147.2	$ 654.5	$ 92.22	$ 50.69	$ 3.95

[1] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price.

All of our reserves are located in the continental United States. The following table sets forth by region the estimated quantities of proved reserves and the percentages thereof that are represented by proved developed reserves as of December 31, 2013:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(MMBOE)		
Texas			
South Texas	75.6	55.4%	29.0%
East Texas	35.9	26.3%	40.9%
Mid-Continent	10.6	7.8%	80.0%
Mississippi	14.2	10.4%	69.2%
Appalachia	0.1	0.1%	100.0%
	136.3	100.0%	40.4%

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2013:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year	14.4	12.4	238	66.5
Revisions of previous estimates	(3.3)	(4.2)	(105)	(25.1)
Extensions, discoveries and other additions	27.7	5.2	27	37.3
Purchase of reserves	5.1	0.6	3	6.1
Conversion to proved developed reserves	(2.4)	(0.6)	(3)	(3.6)
Proved undeveloped reserves at end of year	41.4	13.4	160	81.3

In 2013, our proved undeveloped reserves increased by 14.8 MMBOE. We experienced negative revisions due to locations that are not expected to be drilled during a five-year period primarily in the Haynesville Shale (8.3 MMBOE), Cotton Valley (7.1 MMBOE), Selma Chalk (3.7 MMBOE) and all other locations combined, including the Granite Wash and Marcellus Shale (1.0 MMBOE). We also experienced downward revisions in the Eagle Ford Shale due primarily to the elimination of certain locations (2.2 MMBOE) and revisions to existing locations (2.5 MMBOE) attributable to changes in our development plans including the effects of reduced down-spacing. The balance of negative revisions (0.3 MMBOE) is attributable to non-participation and lease expirations partially offset by improved pricing. Extensions, discoveries and other additions were substantially attributable to our activities in the Eagle Ford Shale and our purchases of reserves were exclusively attributable to the 2013 EF Acquisition. In addition, we converted 3.6 MMBOE from proved undeveloped to proved developed reserves, consisting of 11 gross (8.9 net) wells in the Eagle Ford Shale and 2 gross (0.5 net) wells in the Granite Wash. During 2013, we incurred capital expenditures of approximately $80 million in connection with the conversion of proved undeveloped reserves to proved developed reserves.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by Wright & Company, Inc., our independent third party petroleum engineers. For additional information regarding estimates of proved reserves and other information about our oil and gas reserves, see the Supplemental Information on Oil and Gas Producing Activities (Unaudited) in our Notes to the Consolidated Financial Statements and the report of Wright & Company, Inc., prepared for us and dated January 27, 2014, which is included as an Exhibit to this Annual Report on Form 10-K. We did not file any reports during the year ended December 31, 2013 with any federal authority or agency with respect to our estimate of oil and gas reserves.

Our policies and practices regarding the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and GAAP. Our Vice President, Operations & Engineering is primarily responsible for overseeing the preparation of the reserve estimate by Wright & Company, Inc. Our Vice President, Operations & Engineering has over 28 years of industry experience in the estimation and evaluation of reserve information, holds a B.S. degree in Petroleum Engineering from Texas A&M University and is licensed by the State of Texas as a Professional Engineer. Our internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. For additional information about the risks inherent in our estimates of proved reserves, see Item 1A, "Risk Factors."

Qualifications of Third Party Petroleum Engineers

The technical person primarily responsible for review of our reserve estimates at Wright & Company, Inc. meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Oil and Gas Production, Production Prices and Production Costs

Oil and Gas Production by Region

The following tables set forth by region the average daily production and total production for the periods presented:

	Average Daily Production for the Year Ended December 31,			Total Production for the Year Ended December 31,		
Region	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**
		(BOEPD)			(MBOE)	
Texas						
South Texas [1]	11,208	6,377	2,335	4,091	2,334	852
East Texas	2,795	3,652	5,817	1,020	1,337	2,123
Mid-Continent [2]	2,567	3,309	5,973	937	1,211	2,180
Mississippi	2,058	2,314	2,993	751	847	1,092
Appalachia [3]	68	2,143	4,139	25	784	1,511
	18,696	17,795	21,257	6,824	6,513	7,758

[1] We completed the 2013 EF Acquisition in April 2013.
[2] We sold a substantial portion of our Arkoma Basin properties in August 2011, which represented annual production of approximately 700 MBOE (1,800 BOEPD).
[3] We sold all of our properties in West Virginia, Kentucky and Virginia in July 2012, which represented annual production of approximately 741 MBOE (2,100 BOEPD) in 2012 and 1,500 MBOE (4,100 BOEPD) in 2011.

Production Prices and Production Costs

The following table sets forth the average sales prices per unit of volume and our average production costs, not including ad valorem and production/severance taxes, per unit of production for the periods presented:

	Year Ended December 31,		
	2013	**2012**	**2011**
Average prices:			
Crude oil ($ per Bbl)	$ 101.13	$ 101.95	$ 93.19
NGLs ($ per Bbl)	$ 31.30	$ 35.13	$ 47.83
Natural gas ($ per Mcf)	$ 3.64	$ 2.46	$ 4.10
Aggregate ($ per BOE)	$ 63.11	$ 47.67	$ 38.67
Average production cost ($ per BOE):			
Lease operating	$ 5.20	$ 4.80	$ 4.77
Gathering processing and transportation	1.88	2.18	1.95
	$ 7.08	$ 6.98	$ 6.72

Significant Fields

Our Eagle Ford Shale play in South Texas, which contains primarily oil reserves, represents approximately 55% of our total equivalent proved reserve quantities as of December 31, 2013. Our Carthage field in East Texas, consisting primarily of our Cotton Valley and Haynesville Shale properties, represents approximately 26% of our total equivalent proved reserve quantities as of December 31, 2013. These are the only fields that comprise 15% or more of our total proved reserves as of that date.

The following table sets forth certain information with respect to these fields for the periods presented:

	Year Ended December 31,		
	2013	**2012**	**2011**
Eagle Ford Shale			
Production:			
Crude oil (MBbl)	3,197	1,960	751
NGLs (MBbl)	478	205	55
Natural gas (MMcf)	2,406	1,015	277
Total (MBOE)	4,077	2,334	852
Percent of total company production	60%	36%	11%
Average prices:			
Crude oil ($ per Bbl)	$ 101.55	$ 103.33	$ 93.72
NGLs ($ per Bbl)	$ 26.68	$ 31.43	$ 51.33
Natural gas ($ per Mcf)	$ 3.52	$ 2.56	$ 3.66
Aggregate ($ per BOE)	$ 84.85	$ 90.63	$ 87.10
Average production cost ($ per BOE) [1]:			
Lease operating	$ 4.30	$ 3.12	$ 1.67
Gathering processing and transportation	1.08	0.72	0.48
	$ 5.38	$ 3.84	$ 2.15
Carthage Field			
Production:			
Crude oil (MBbl)	60	68	106
NGLs (MBbl)	191	281	440
Natural gas (MMcf)	4,168	5,467	8,417
Total (MBOE)	945	1,260	1,949
Percent of total company production	14%	19%	25%
Average prices:			
Crude oil ($ per Bbl)	$ 99.80	$ 96.61	$ 93.97
NGLs ($ per Bbl)	$ 35.36	$ 36.31	$ 49.82
Natural gas ($ per Mcf)	$ 3.38	$ 2.30	$ 3.69
Aggregate ($ per BOE)	$ 28.36	$ 23.29	$ 32.29
Average production cost ($ per BOE) [1]:			
Lease operating	$ 6.84	$ 4.64	$ 4.76
Gathering processing and transportation	2.07	2.21	1.90
	$ 8.91	$ 6.85	$ 6.66

[1] Excludes production/severance and ad valorem taxes.

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development and exploratory wells that we drilled during the years ended December 31, 2013, 2012 and 2011 and wells that were in progress at the end of each year. The number of wells drilled refers to the number of wells completed at any time during the year, regardless of when drilling was initiated.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	58	34.1	36	27.8	45	32.1
Non-productive	—	—	—	—	—	—
Under evaluation	1	0.5	—	—	2	1.3
Total development	59	34.6	36	27.8	47	33.4
Exploratory						
Productive	—	—	5	3.9	5	3.8
Non-productive	—	—	—	—	4	2.7
Under evaluation	—	—	1	1.0	—	—
Total exploratory	—	—	6	4.9	9	6.5
Total	59	34.6	42	32.7	56	39.9
Wells in progress at end of year [1]	16	11.5	3	2.7	7	5.8

[1] Includes three gross (2.8 net) wells completing, eight gross (5.0 net) waiting on completion and five gross (3.7 net) wells being drilled as of December 31, 2013.

The following table sets forth the regions in which we drilled our wells for the periods presented:

	2013		2012		2011	
Region	Gross	Net	Gross	Net	Gross	Net
Texas						
South Texas [1]	57	34.1	35	29.5	32	26.7
East Texas	—	—	—	—	—	—
Mid-Continent	2	0.5	7	3.2	19	8.9
Mississippi	—	—	—	—	—	—
Appalachia	—	—	—	—	5	4.3
	59	34.6	42	32.7	56	39.9

[1] Includes six gross (2.2 net) wells acquired in the 2013 EF Acquisition that were in progress when acquired.

Present Activities

As of December 31, 2013, we had 16 gross (11.5 net) wells in progress, all of which were located in South Texas. As of February 19, 2014, four gross (2.7 net) of these wells, all of which were Eagle Ford Shale wells, had been successfully completed and were producing.

Delivery Commitments

We generally sell our oil, NGL and natural gas products using short-term floating price physical and spot market contracts. Although it is not our general practice, from time to time we enter into certain transactions in which we provide production commitments extending beyond one month. As of December 31, 2013, we did not have any material commitments to provide a fixed and determinable quantity of our products beyond the current month.

Productive Wells

The following table sets forth the productive wells in which we had a working interest as of December 31, 2013:

	Primarily Oil		Primarily Natural Gas		Total	
Region	Gross	Net	Gross	Net	Gross	Net
Texas						
South Texas	180	116.9	—	—	180	116.9
East Texas	—	—	356	254.3	356	254.3
Mid-Continent	11	7.1	99	42.3	110	49.4
Mississippi	—	—	564	545.6	564	545.6
Appalachia	—	—	3	3.0	3	3.0
	191	124.0	1,022	845.2	1,213	969.2

Of the total wells presented in the table above, we are the operator of 1,094 gross (166 oil and 928 gas) and 928.3 net (112.6 oil and 815.6 gas) wells. In addition to the above working interest wells, we own royalty interests in 10 gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2013 (in thousands):

	Developed		Undeveloped		Total	
Region	Gross	Net	Gross	Net	Gross	Net
Texas						
South Texas	60.3	39.4	55.4	38.5	115.7	77.9
East Texas	43.9	31.9	2.4	1.5	46.3	33.4
Mid-Continent	19.8	10.0	32.2	20.0	52.0	30.0
Mississippi	34.9	27.8	1.0	0.4	35.9	28.2
Appalachia	1.7	1.1	28.8	20.6	30.5	21.7
	160.6	110.2	119.8	81.0	280.4	191.2

The primary terms of our leases generally range from three to five years and we do not have any concessions. As of December 31, 2013, our net undeveloped acreage is scheduled to expire as shown in the table below, unless the primary lease terms are, where appropriate, extended, HBP or otherwise changed:

	2014	2015	2016	Thereafter
Percent of gross undeveloped acreage	25%	17%	22%	36%
Percent of net undeveloped acreage	20%	12%	17%	51%

We do not believe that the scheduled expiration of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3 Legal Proceedings

Since December 2013, we have been involved in an arbitration with Magnum Hunter Resources Corporation ("MHR"), the seller in our 2013 EF Acquisition. The arbitration relates to disputes we have with MHR regarding contractual adjustments to the purchase price for the 2013 EF Acquisition and suspense funds that we believe MHR is obligated to transfer to us. On February 3, 2014, both we and MHR submitted initial briefs describing our respective positions to the arbitrator. MHR has acknowledged that it owes us approximately $26.5 million; we believe the amount is higher. Both parties are scheduled to submit rebuttals to the initial briefs on March 3, 2014. We expect this matter to be resolved early during the second quarter of 2014.

See Note 12 to our Consolidated Financial Statements included in Item 8,"Financial Statements and Supplementary Data," for a more detailed discussion of our legal contingencies. We are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject. See Item 1, "Business—Government Regulation and Environmental Matters," for a more detailed discussion of our material environmental obligations.

Item 4 Mine Safety Disclosures

Not applicable.

Part II

Item 5 Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock is traded on the NYSE under the symbol "PVA." The high and low sales prices (composite transactions) and dividends declared related to each fiscal quarter in 2013 and 2012 were as follows:

Quarter Ended	Sales Price High	Sales Price Low	Cash Dividends Declared
December 31, 2013	$ 11.21	$ 6.50	$ —
September 30, 2013	$ 6.72	$ 4.50	$ —
June 30, 2013	$ 5.17	$ 3.56	$ —
March 31, 2013	$ 5.00	$ 3.97	$ —
December 31, 2012	$ 6.72	$ 4.07	$ —
September 30, 2012	$ 7.74	$ 6.01	$ —
June 30, 2012	$ 7.37	$ 3.92	$ 0.05625
March 31, 2012	$ 6.27	$ 4.27	$ 0.05625

Equity Holders

As of February 19, 2014, there were 399 record holders and 10,936 beneficial owners (held in street name) of our common stock.

Dividends

In July 2012, we discontinued the quarterly dividend on our common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

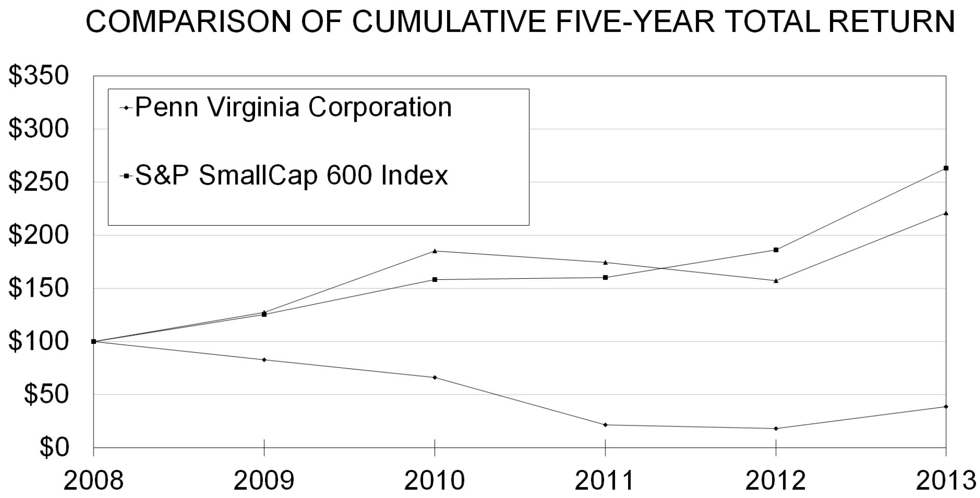
See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" and Note 14 to our Consolidated Financial Statements included in Item 8. "Financial Statements and Supplementary Data" for information regarding shares of common stock authorized for issuance under our stock compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any shares of our common stock in 2013. Prior to 2012, certain of our employees made elective deferrals of compensation under the Penn Virginia Corporation Supplemental Employee Retirement Plan, or SERP, a portion of which was invested, at the employee's direction, in our common stock. In addition, a portion of the compensation paid to certain non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon retirement from our board of directors. Common stock held by the SERP and deferred common stock units that have not been converted into common stock are presented for financial reporting purposes as treasury stock carried at cost.

Performance Graph

The following graph compares our five-year cumulative total shareholder return (assuming reinvestment of dividends) with the cumulative total return of the Standard & Poor's 600 Oil & Gas Exploration & Production Index and the Standard & Poor's Small Cap 600 Index. As of December 31, 2013, there were eleven exploration and production companies in the Standard & Poor's 600 Oil & Gas Exploration & Production Index: Approach Resources Inc., Carrizo Oil & Gas, Inc., Comstock Resources, Inc., Contango Oil & Gas Company, Forest Oil Corporation, Northern Oil & Gas, Inc., PDC Energy, Inc., Penn Virginia Corporation, PetroQuest Energy, Inc., Stone Energy Corporation and Swift Energy Company. The graph assumes $100 is invested on January 1, 2009 in us and each index at December 31, 2008 closing prices.



	December 31,									
	2009		2010		2011		2012		2013	
Penn Virginia Corporation	$	83.02	$	66.41	$	21.41	$	18.23	$	38.98
S&P Small Cap 600 Index	$	125.57	$	158.60	$	160.22	$	186.37	$	263.37
S&P 600 Oil & Gas Exploration & Production Index	$	127.39	$	185.22	$	174.39	$	157.62	$	221.05

Item 6 Selected Financial Data

The following selected historical financial and operating information was derived from our Consolidated Financial Statements as of and for the years ended December 31, 2013, 2012, 2011, 2010 and 2009. The selected financial data should be read in conjunction with our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data."

	2013	2012	2011	2010	2009
	(in thousands, except per share amounts)				
Statements of Operations Data[1]:					
Revenues	$ 431,468	$ 317,149	$ 306,005	$ 254,438	$ 235,206
Operating loss[2]	$ (92,046)	$ (147,091)	$ (155,419)	$ (98,808)	$ (205,346)
Loss from continuing operations	$ (143,070)	$ (104,589)	$ (132,915)	$ (65,327)	$ (130,856)
Net income (loss)	$ (143,070)	$ (104,589)	$ (132,915)	$ 19,667	$ (77,368)
Loss attributable to Penn Virginia Corporation	$ (143,070)	$ (104,589)	$ (132,915)	$ (8,423)	$ (114,643)
Preferred stock dividends	$ 6,900	$ 1,687	$ —	$ —	$ —
Loss attributable to common shareholders	$ (149,970)	$ (106,276)	$ (132,915)	$ (8,423)	$ (114,643)
Common Stock Data[1]:					
Earnings (loss) per common share, basic					
Continuing operations	$ (2.41)	$ (2.22)	$ (2.90)	$ (1.44)	$ (2.99)
Discontinued operations	$ —	$ —	$ —	$ 0.12	$ 0.37
Gain on sale of discontinued operations	$ —	$ —	$ —	$ 1.13	$ —
Net income (loss)	$ (2.41)	$ (2.22)	$ (2.90)	$ (0.19)	$ (2.62)
Earnings (loss) per common share, diluted					
Continuing operations	$ (2.41)	$ (2.22)	$ (2.90)	$ (1.44)	$ (2.99)
Discontinued operations	$ —	$ —	$ —	$ 0.12	$ 0.37
Gain on sale of discontinued operations	$ —	$ —	$ —	$ 1.13	$ —
Net income (loss)	$ (2.41)	$ (2.22)	$ (2.90)	$ (0.19)	$ (2.62)
Weighted-average shares outstanding:					
Basic	62,335	47,919	45,784	45,553	43,811
Diluted	62,335	47,919	45,784	45,553	43,811
Actual shares outstanding at year-end	65,307	55,117	45,714	45,557	45,272
Dividends declared per share of common stock	$ —	$ 0.1125	$ 0.225	$ 0.225	$ 0.225
Market value at year-end	$ 9.43	$ 4.41	$ 5.29	$ 16.82	$ 21.29
Number of shareholders	11,335	7,656	6,787	6,708	3,486
Preferred Stock Data[3]:					
Actual shares outstanding at year-end	11,500	11,500	—	—	—
Dividends declared per share of preferred stock	$ 600.00	$ 146.67	$ —	$ —	$ —
Balance Sheet and Other Financial Data[1]:					
Property and equipment, net	$ 2,237,304	$ 1,723,359	$ 1,777,575	$ 1,705,584	$ 1,479,452
Total assets	$ 2,507,087	$ 1,842,989	$ 1,943,053	$ 1,944,600	$ 2,888,507
Total debt	$ 1,281,000	$ 594,759	$ 697,307	$ 506,536	$ 498,427
Shareholders' equity	$ 788,804	$ 895,116	$ 846,309	$ 980,276	$ 1,237,999
Cash provided by operating activities	$ 261,512	$ 241,458	$ 144,741	$ 79,839	$ 117,733
Cash paid for capital expenditures	$ 504,203	$ 370,907	$ 445,623	$ 405,994	$ 205,676
Other Statistical Data:					
Total production (MBOE)	6,824	6,513	7,759	7,867	8,500
Proved reserves (MMBOE)	136	113	147	157	156

[1] Our former coal and natural resource management and natural gas midstream businesses are reported as discontinued operations for 2010 and 2009.

[2] Operating loss for 2013, 2012, 2011, 2010 and 2009 included impairment charges of $132.2 million, $104.5 million, $104.7 million, $46.0 million and $106.4 million related to our oil and gas properties and other assets.

[3] Outstanding preferred stock is in the form of 1,150,000 depositary shares each representing a 1/100th ownership interest in a share of our 6% Series A Convertible Perpetual Preferred Stock, or 6% Preferred Stock. Each share of the 6% Preferred Stock has a liquidation preference of $10,000 per share or $100 per depositary share.

ItemManagement's Discussion and Analysis of Financial Condition and Results of Operations 7

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, "Financial Statements and Supplementary Data." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Certain year-over-year changes are presented as not meaningful, or "NM," where disclosure of the actual value does not otherwise enhance the analysis. Also, due to the combination of different units of volumetric measure and the number of decimal places presented, certain results may not calculate explicitly from the values presented in the tables.

Overview and Executive Summary

We are an independent oil and gas company engaged in the exploration, development and production of oil, NGLs and natural gas in various onshore regions of the United States. Our current operations consist primarily of the drilling of unconventional horizontal development wells in shale formations and are currently concentrated in the Eagle Ford Shale in South Texas. We also have operations in the Granite Wash in the Mid-Continent (primarily Oklahoma), the Haynesville Shale and Cotton Valley in East Texas and the Selma Chalk in Mississippi. As of December 31, 2013, we had proved oil and gas reserves of approximately 136 MMBOE.

The following table sets forth certain summary operating and financial statistics for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Total production (MBOE)	6,824	6,513	7,759
Daily production (BOEPD)	18,696	17,795	21,257
Crude oil and NGL production (MBbl)	4,418	3,136	2,190
Crude oil and NGL production as a percent of total	65%	48%	28%
Product revenues, as reported	$ 430,693	$ 310,484	$ 300,046
Product revenues, adjusted for derivatives	$ 429,651	$ 338,802	$ 323,608
Crude oil and NGL revenues as a percent of total, as reported	88%	84%	54%
Realized prices:			
Crude oil ($/Bbl)	$ 101.13	$ 101.95	$ 93.19
NGL ($/Bbl)	$ 31.30	$ 35.13	$ 47.83
Natural gas ($/Mcf)	$ 3.64	$ 2.46	$ 4.10
Aggregate ($/BOE)	$ 63.11	$ 47.67	$ 38.67
Production and lifting costs ($/BOE):			
Lease operating	$ 5.20	$ 4.80	$ 4.77
Gathering, processing and transportation	$ 1.88	$ 2.18	$ 1.95
Production and ad valorem taxes ($/BOE)	$ 3.28	$ 1.63	$ 1.76
General and administrative ($/BOE) [1]	$ 6.69	$ 5.87	$ 4.97
Total operating costs ($/BOE)	$ 17.05	$ 14.48	$ 13.45
Depreciation, depletion and amortization ($/BOE)	$ 35.99	$ 31.68	$ 20.95
Cash provided by operating activities [2]	$ 261,512	$ 241,458	$ 144,741
Cash paid for capital expenditures, excluding 2013 EF Acquisition	$ 504,203	$ 370,907	$ 445,623
Cash and cash equivalents at end of period	$ 23,474	$ 17,650	$ 7,512
Debt outstanding, net of discount, at end of period	$ 1,281,000	$ 594,759	$ 697,307
Liquidation preference of convertible preferred stock at end of period	$ 115,000	$ 115,000	$ —
Credit available under revolving credit facility at end of period [3]	$ 191,346	$ 297,922	$ 199,600
Proved reserves (MMBOE)	136	113	147
Net development wells drilled	34.6	27.8	33.4
Net exploratory wells drilled	—	4.9	6.5

[1] Excludes equity-classified share-based compensation, which is a non-cash expense, of $0.84, $0.98 and $0.96 and restructuring expenses and 2013 EF Acquisition transaction expenses of $0.38, $0.20 and $0.30 for the years ended December 31, 2013, 2012 and 2011.

[2] Includes the receipt of a federal income tax refund of approximately $32 million in the year ended December 31, 2012 attributable to 2010 and prior years.

[3] As reduced by outstanding borrowings and letters of credit and limited by financial covenants, if applicable. Also, excludes an additional $25 million attributable to the excess of the borrowing base of $425 million over the current commitment of $400 million.

In 2013, our crude oil and NGL production represented the majority of our total production consistent with our strategy to become a more liquids-focused oil and gas exploration and production company. As illustrated in the table above and as discussed further in the *Key Developments* and *Results of Operations* that follow, crude oil and NGL production was 65 percent of our total production for 2013 and the revenues generated from liquids production represented 88 percent of our total product revenues. Consistent with this strategic shift in investment and operational focus, we realized significantly higher cash operating margins. Our cash operating margin increased $20.84 per BOE, or 83 percent, to $46.06 per BOE in 2013 from $25.22 per BOE in 2011. Due primarily to the growth in cash operating margins, our cash provided by operating activities also increased significantly each successive year, despite higher interest payment requirements associated with our increased leverage. In 2013, cash from operating activities increased $116.8 million, or 81 percent, to $261.5 million from $144.7 million in 2011.

Our growth in crude oil and NGL production has been focused almost exclusively in the Eagle Ford Shale in South Texas. Since our initial lease acquisition in this region in 2010, we have drilled or acquired and turned in line 179 gross (116.7 net) total wells (operated and non-operated) through February 19, 2014. Our growth plans accelerated in April 2013 with the 2013 EF Acquisition and additional leasehold acquisitions, both of which increased the scope and scale of our Eagle Ford Shale operations. Accordingly, our cash paid for capital expenditures grew to $504.2 million, excluding the 2013 EF Acquisition, in 2013 from $370.9 in 2012 and is projected to be up to approximately $640 million in 2014. This contemplates a total of up to six operated rigs in the Eagle Ford Shale for 2014 as compared to an average of two prior to the 2013 EF Acquisition.

Our expansion in the Eagle Ford Shale and our overall shift in investment to liquids-focused opportunities has been financed over the past several years by a combination of cash from operating activities, the sale of non-core assets, borrowings under the Revolver and a mix of debt and equity offerings. Our most recent financing transaction occurred in April 2013 with the private placement and subsequent registration of $775 million of 8.5% Senior Notes due 2020, or 2020 Senior Notes. The 2020 Senior Notes were used to finance a portion of the 2013 EF Acquisition as well as adjust our total capitalization by retiring our high-cost $300 million of 10.375% Senior Notes due 2016, or 2016 Senior Notes resulting in an annual reduction of interest payments of $5.6 million. We also issued 10 million shares of common stock to the seller in connection with the 2013 EF Acquisition.

Key Developments

The following general business developments and corporate actions had or will have a significant impact on the financial reporting and disclosure of our financial position, results of operations and cash flows: (i) drilling results and future development plans for the Eagle Ford Shale, (ii) the 2013 EF Acquisition, (iii) the amendment, or Amendment, of the Revolver, and the borrowing base redetermination thereunder, (iv) the sale of our natural gas gathering assets in South Texas, (v) hedging a portion of our oil and gas production through calendar year 2015 to the levels permitted by our Revolver and our internal policies, (vi) the tender offer and the redemption, or the Tender Offer and the Redemption, of our 2016 Senior Notes and (vii) the private placement and subsequent registration of our 2020 Senior Notes to finance the 2013 EF Acquisition, the Tender Offer and the Redemption.

Drilling Results and Future Development Plans for the Eagle Ford Shale

During 2013, we drilled 49 gross (30.8 net) successful wells, and our joint venture partner drilled seven (2.8 net) successful non-operated wells in the Eagle Ford Shale. We also drilled one (0.5 net) well that is currently under evaluation.

Our Eagle Ford Shale production was approximately 11,169 net BOEPD during 2013 and 13,111 net BOEPD during the fourth quarter of 2013 with oil comprising approximately 78 percent, NGLs approximately 12 percent and natural gas approximately 10 percent. In the Eagle Ford Shale, we have a total of 179 gross (116.7 net) producing wells, 13 gross (10.1 net) operated wells completing or waiting on completion, two gross (0.9 net) outside operated wells being completed, six gross (4.2 net) operated wells being drilled and no outside operated wells being drilled as of February 19, 2014. While our production during the fourth quarter was consistent with previous guidance, we had a number of wells brought on line later than anticipated and these wells did not contribute as much to the fourth quarter results as we had expected. In addition, our non-operated partner has suspended its drilling program. In response, we have increased our operated drilling rig count to six rigs where we intend to remain during 2014, subject to market conditions.

The average total drilling and completion cost per frac stage for our operated Eagle Ford Shale wells was approximately $380,000 in the fourth quarter of 2013, as compared to $390,000 in the third quarter of 2013. In addition to the sequential decrease in costs per frac stage, our well productivity per stage increased as a result of pumping additional proppant and the continued use of multi-well pads and “zipper fracs.” A total of 22 of our recently drilled wells were drilled off of ten multi-well pads, with an average effective nominal spacing of approximately 60 acres.

We have approximately 118,000 gross (80,000 net) acres as of February 19, 2014, which to a large extent are contiguous and the majority of which are in the “volatile oil window” of the Eagle Ford Shale. Approximately 96,800 gross (70,300 net) acres are operated by us.

Acquisition and Integration of New Eagle Ford Shale Assets

We closed the 2013 EF Acquisition on April 24, 2013, or the Acquisition Date, and acquired approximately 40,600 gross (17,700 net) mineral acres, including producing and undeveloped property, located in Gonzales and Lavaca Counties, Texas most of which was adjacent to our existing Eagle Ford Shale position. The 2013 EF Acquisition was originally valued at $401 million with an effective date of January 1, 2013, or the Effective Date. On the Acquisition Date, we paid approximately $380 million in cash, including approximately $19 million of initial purchase price adjustments related to the period from the Effective Date to the Acquisition Date utilizing a portion of the proceeds from the 2020 Senior Notes offering, and issued to the seller 10 million shares of our common stock, or Shares, with a fair value of $4.23 per Share. Shortly after the Acquisition Date, certain of our joint interest partners exercised preferential rights related to the 2013 EF Acquisition. We received approximately $21 million from the exercise of those rights, which was recorded as a decrease to the purchase price of the 2013 EF Acquisition. In September 2013, the seller divested all of the Shares. See Item 3, "Legal Proceedings" for information regarding an arbitration in which we are involved with the seller.

The 2013 EF Acquisition included working interests in 46 gross (22.1 net) producing wells. At the time of the 2013 EF Acquisition, the estimated net oil and gas production for the acquired assets was approximately 2,700 BOEPD. Based on the seller's third-party reserve engineering firm's year-end 2012 review of the acquired assets, proved reserves were approximately 12.0 MMBOE, 96 percent of which were oil and NGLs and 37 percent of which were proved developed.

Revolver Amendment and Borrowing Base Redetermination

The Revolver was amended in October 2013 to increase the revolving commitment from $350 million to $400 million. Concurrently, the borrowing base under the Revolver was increased from $350 million to $425 million. The Amendment also provides for an extension of the current maximum leverage ratio of 4.5 to 1.0 through June 30, 2014 and allows the Revolver's administrative agent to replace any lender who fails to approve a borrowing base increase approved by lenders representing two thirds of the aggregate commitment.

Sale of South Texas Natural Gas Gathering Assets

In December 2013, we entered into an agreement to sell our natural gas gathering assets in South Texas. The sale was completed in January 2014 and provided net proceeds of approximately $94 million, net to our working interest. Accordingly, the net carrying value of these assets is included on our Consolidated Balance Sheet as a component of current assets.

Commodity Hedging Activities

We have hedged approximately 70 percent of our estimated crude oil production for the first half of 2014 and approximately 65 percent for the second half of 2014 at a weighted-average floor price of $93.55 per barrel. In addition, we have hedged approximately 40 percent of our estimated natural gas production through the third quarter of 2014 at a weighted-average floor price of $4.13 per MMBtu and approximately 15 percent for the 2014 - 2015 winter at a weighted-average floor price of $4.50 per MMBtu.

Tender Offer and Redemption of the 2016 Senior Notes

In April 2013, we initiated the Tender Offer for any and all of the $300 million principal amount of the 2016 Senior Notes. Holders of approximately 58% of the 2016 Senior Notes tendered their notes. The total consideration payable for each $1,000 principal amount of those 2016 Senior Notes tendered was $1,065.34, which included a consent payment of $30.00 per $1,000 principal amount. In April 2013, we paid approximately $191 million, including accrued interest of $6.5 million, for the 2016 Senior Notes tendered. In May 2013, we made an irrevocable election in connection with the Redemption to redeem the remaining 42% of the 2016 Senior Notes outstanding in accordance with the 2016 Senior Notes indenture. We paid a total of $1,061.31 per $1,000 principal amount of the 2016 Senior Notes, or approximately $140 million, including accrued interest of $5.3 million, in connection with the Redemption. We recognized a loss on the extinguishment of debt of $29.2 million during the three months ended June 30, 2013 in connection with the Tender Offer and the Redemption, including non-cash charges of $10.0 million attributable to the write-off of unamortized debt issuance costs and the remaining debt discount associated with the 2016 Senior Notes.

Issuance of 2020 Senior Notes

On April 24, 2013, we completed a private placement of $775 million of 2020 Senior Notes. The 2020 Senior Notes were priced at par and interest is payable on June 15 and December 15 of each year. The 2020 Senior Notes are fully and unconditionally guaranteed by all of our material subsidiaries, or Guarantor Subsidiaries. Approximately $380 million of the net proceeds from the private placement were used to finance the cash consideration for the 2013 EF Acquisition, including initial purchase price adjustments. The remaining net proceeds were used to pay down borrowings under the Revolver and to fund a portion of the Tender Offer and the Redemption. In July 2013, we completed an exchange offer to register of all of the 2020 Senior Notes.

Results of Operations

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Production

The following tables set forth a summary of our total and daily production volumes by product and geographic region for the periods presented (certain results in the tables below may not calculate due to rounding):

Crude Oil	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
South Texas	3,199.5	1,959.6	1,239.9	8,765.8	5,354.0	3,411.8	64 %
East Texas	63.4	71.1	(7.6)	173.7	194.2	(20.5)	(11)%
Mid-Continent	160.4	206.2	(45.7)	439.5	563.3	(123.8)	(22)%
Mississippi	11.9	14.1	(2.2)	32.6	38.6	(6.0)	(15)%
Appalachia	0.1	1.0	(0.8)	0.3	2.6	(2.3)	(89)%
	3,435.4	2,251.9	1,183.6	9,411.8	6,152.6	3,259.2	53 %

NGLs	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
South Texas	485.3	205.2	280.1	1,329.5	560.8	768.7	137 %
East Texas	190.7	280.7	(90.0)	522.6	767.0	(244.4)	(32)%
Mid-Continent	306.5	397.2	(90.7)	839.7	1,085.4	(245.7)	(23)%
Mississippi	—	—	—	—	—	—	— %
Appalachia	—	0.8	(0.8)	—	2.1	(2.1)	(100)%
	982.5	884.0	98.6	2,691.8	2,415.3	276.5	11 %

Natural Gas	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
	(MMcf)			(MMcf per day)			
Texas							
South Texas	2,436	1,015	1,421	6.7	2.8	3.9	140 %
East Texas	4,593	5,909	(1,316)	12.6	16.1	(3.5)	(22)%
Mid-Continent	2,823	3,646	(823)	7.7	10.0	(2.3)	(23)%
Mississippi	4,436	4,997	(561)	12.2	13.7	(1.5)	(11)%
Appalachia	147	4,695	(4,548)	0.4	12.8	(12.4)	(97)%
	14,435	20,261	(5,827)	39.6	55.4	(15.8)	(29)%

Combined Total	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
	(MBOE)			(BOE per day)			
Texas							
South Texas[1]	4,091	2,334	1,757	11,208	6,377	4,831	75 %
East Texas	1,020	1,337	(317)	2,795	3,652	(857)	(24)%
Mid-Continent	937	1,211	(274)	2,567	3,309	(742)	(23)%
Mississippi	751	847	(96)	2,058	2,314	(256)	(11)%
Appalachia[2]	25	784	(759)	68	2,143	(2,074)	(97)%
	6,824	6,513	311	18,696	17,795	901	5 %

[1] Comprised primarily of production from our Eagle Ford Shale wells as well as our Pearsall Shale and Austin Chalk wells.
[2] Subsequent to the sale of our Appalachian natural gas properties in July 2012, our remaining production from this region is provided by 3 gross (3.0 net) wells in the Marcellus Shale.

Total production increased during 2013 compared to 2012 due primarily to the 2013 EF Acquisition and the continued expansion of our development program in the Eagle Ford Shale. The increase was partially offset by the effect of the sale of our Appalachian natural gas properties in July 2012 along with natural production declines in our East Texas and Mid-Continent regions. The effect of the sale of the Appalachian properties was approximately 741 MBOE. Approximately 65% of total production during 2013 was attributable to oil and NGLs, which represents an increase of approximately 41% over the prior year. During 2013, our Eagle Ford Shale production represented approximately 60% of our total production as compared to approximately 36% from this play during 2012.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographic region for the periods presented:

Crude Oil	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2013	**2012**	**(Unfavorable)**	**2013**	**2012**	**(Unfavorable)**
				($ per Bbl)		
Texas						
South Texas	$ 324,899	$ 202,479	$ 122,420	$ 101.55	$ 103.33	$ (1.78)
East Texas	6,325	6,862	(537)	99.69	96.55	3.14
Mid-Continent	14,920	18,667	(3,747)	93.01	90.55	2.46
Mississippi	1,249	1,477	(228)	104.79	104.66	0.13
Appalachia	14	87	(73)	101.45	91.29	10.16
	$ 347,407	$ 229,572	$ 117,835	$ 101.13	$ 101.95	$ (0.82)

NGLs	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2013	**2012**	**(Unfavorable)**	**2013**	**2012**	**(Unfavorable)**
				($ per Bbl)		
Texas						
South Texas	$ 12,969	$ 6,451	$ 6,518	$ 26.72	$ 31.43	$ (4.71)
East Texas	6,743	10,195	(3,452)	35.36	36.32	(0.96)
Mid-Continent	11,036	14,365	(3,329)	36.01	36.16	(0.15)
Mississippi	—	—	—	—	—	—
Appalachia	—	40	(40)	—	51.61	NM
	$ 30,748	$ 31,051	$ (303)	$ 31.30	$ 35.13	$ (3.83)

Natural Gas	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2013	**2012**	**(Unfavorable)**	**2013**	**2012**	**(Unfavorable)**
				($ per Mcf)		
Texas						
South Texas	$ 8,586	$ 2,593	$ 5,993	$ 3.52	$ 2.56	$ 0.96
East Texas	15,571	13,607	1,964	3.39	2.30	1.09
Mid-Continent	10,655	7,920	2,735	3.77	2.17	1.60
Mississippi	17,157	14,387	2,770	3.87	2.88	0.99
Appalachia	569	11,354	(10,785)	3.87	2.42	1.45
	$ 52,538	$ 49,861	$ 2,677	$ 3.64	$ 2.46	$ 1.18

Combined Total	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2013	**2012**	**(Unfavorable)**	**2013**	**2012**	**(Unfavorable)**
				($ per BOE)		
Texas						
South Texas	$ 346,454	$ 211,523	$ 134,931	$ 84.69	$ 90.63	$ (5.94)
East Texas	28,639	30,664	(2,025)	28.08	22.94	5.14
Mid-Continent	36,611	40,952	(4,341)	39.07	33.81	5.26
Mississippi	18,406	15,864	2,542	24.51	18.73	5.78
Appalachia	583	11,481	(10,898)	23.32	14.64	8.68
	$ 430,693	$ 310,484	$ 120,209	$ 63.11	$ 47.67	$ 15.44

As illustrated below, the effect of higher oil and NGL production volume coupled with improved natural gas prices more than offset the overall decline in crude oil and NGL prices and natural gas production volume.

The following table provides an analysis of the change in our revenues for 2013 as compared to 2012:

	Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ 120,652	$ (2,817)	$ 117,835
NGL	3,460	(3,763)	(303)
Natural gas	(14,356)	17,033	2,677
	$ 109,756	$ 10,453	$ 120,209

Effects of Derivatives

In 2013, we paid $1.0 million and, in 2012, we received $28.3 million in cash settlements of oil and gas derivatives. The following table reconciles crude oil and natural gas revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Favorable	
	2013	2012	(Unfavorable)	% Change
Crude oil revenues as reported	$ 347,407	$ 229,572	$ 117,835	51 %
Cash settlements on crude oil derivatives, net	(2,624)	8,428	(11,052)	(131)%
	$ 344,783	$ 238,000	$ 106,783	45 %
Crude oil prices per Bbl, as reported	$ 101.13	$ 101.95	$ (0.82)	(1)%
Cash settlements on crude oil per Bbl	(0.76)	3.74	(4.50)	(120)%
	$ 100.37	$ 105.69	$ (5.32)	(5)%
Natural gas revenues as reported	$ 52,538	$ 49,861	$ 2,677	5 %
Cash settlements on natural gas derivatives, net	1,582	19,890	(18,308)	(92)%
	$ 54,120	$ 69,751	$ (15,631)	(22)%
Natural gas prices per Mcf, as reported	$ 3.64	$ 2.46	$ 1.18	48 %
Cash settlements on natural gas derivatives per Mcf	0.11	0.98	(0.87)	(89)%
	$ 3.75	$ 3.44	$ 0.31	9 %

Gain (Loss) on Sales of Property and Equipment

In 2013, we recognized losses related to certain properties in West Virginia associated with our 2012 sale of Appalachian natural gas assets as well as certain post-closing adjustments for other asset sales that occurred in prior years. In 2012, we recognized a gain attributable to the sale of substantially all of our Appalachian natural gas assets. In addition, we recognized several individually insignificant gains and losses on the sale of property, equipment, tubular inventory and well material during both periods.

Other Revenues

Other revenues, which includes gathering, transportation, compression and water disposal fees and other miscellaneous operating income, net of marketing and related expenses, decreased during 2013 due primarily to accretion expense attributable to our unused firm transportation obligation in the Appalachian region partially offset by a gain of $1.6 million on the sale of certain proprietary seismic data. Total accretion expense recognized during 2013 was $1.7 million representing a full year as compared to $0.6 million for one quarter in 2012.

Production and Lifting Costs

	Year Ended December 31,		Favorable	
	2013	2012	(Unfavorable)	% Change
Lease operating	$ 35,461	$ 31,266	$ (4,195)	(13)%
Per unit of production ($/BOE)	$ 5.20	$ 4.80	$ (0.40)	(8)%

Lease operating expense increased during 2013 due primarily to higher subsurface maintenance costs for wells located in East Texas. In addition, we incurred subsurface maintenance costs for certain wells in the 2013 EF Acquisition in which we had to remove submersible pumps and replace them with rods and pumps. We also incurred higher water disposal and chemical costs associated with our increased oil production. These increases were partially offset by the effect of the sale of our higher-cost Appalachian natural gas properties in July 2012.

	Year Ended December 31, 2013	2012	Favorable (Unfavorable)	% Change
Gathering, processing and transportation	$ 12,839	$ 14,196	$ 1,357	10%
Per unit production ($/BOE)	$ 1.88	$ 2.18	$ 0.30	14%

Gathering, processing and transportation charges decreased during 2013 as compared to 2012 due primarily to the effect of the sale of our higher-cost Appalachian properties in July 2012, partially offset by an increase in processing costs related to expanded natural gas production in the Eagle Ford Shale.

Production and Ad Valorem Taxes

	Year Ended December 31, 2013	2012	Favorable (Unfavorable)	% Change
Production/severance taxes	$ 17,355	$ 7,534	$ (9,821)	(130)%
Ad valorem taxes	5,049	3,100	(1,949)	(63)%
	$ 22,404	$ 10,634	$ (11,770)	(111)%
Per unit production ($/BOE)	$ 3.28	$ 1.63	$ (1.65)	(101)%
Production/severance tax rate as a percent of product revenue	4.03%	2.43%		

Production and ad valorem taxes increased during 2013 due primarily to our increased leasing and drilling activities in the Eagle Ford Shale in Gonzales and Lavaca Counties. In addition, we recognized approximately $4 million of non-recurring credits in the 2012 period for severance tax rebates on certain horizontal and ultra-deep natural gas wells in Oklahoma and Texas.

General and Administrative

	Year Ended December 31, 2013	2012	Favorable (Unfavorable)	% Change
Recurring general and administrative expenses	$ 40,410	$ 37,547	$ (2,863)	(8)%
Share-based compensation (liability-classified)	4,116	714	(3,402)	NM
Share-based compensation (equity-classified)	5,781	6,347	566	9 %
2013 EF Acquisition transaction costs	2,587	—	(2,587)	NM
2013 EF Acquisition integration costs	442	—	(442)	NM
ERP system development costs	655	—	(655)	NM
Restructuring expenses	7	1,292	1,285	99 %
	$ 53,998	$ 45,900	$ (8,098)	(18)%
Per unit of production ($/BOE)	$ 7.91	$ 7.05	$ (0.86)	(12)%
Per unit of production excluding share-based compensation, acquisition transaction costs and restructuring charges ($/BOE)	$ 6.69	$ 5.87	$ (0.82)	(14)%

Recurring general and administrative expenses increased due primarily to higher compensation, benefits and cash-based incentive charges resulting from higher employee headcount. Liability-classified share-based compensation is attributable to our performance-based restricted stock units, or PBRSUs, and represents mark-to-market charges associated with the increase in fair value of both the 2013 and 2012 PBRSU grants. Equity-classified share-based compensation charges attributable to stock options and restricted stock units, which represent non-cash expenses, decreased during 2013 due primarily to fewer employees receiving grants. We incurred transaction costs associated with the 2013 EF Acquisition including advisory, legal, due diligence and other professional fees, as well as certain integration expenses including transition accounting services, settlement statement audit fees and costs to convert acquired land and related records for use in our systems. In 2013, we initiated a project to replace certain of our primary information technology platforms with an integrated ERP system that became operational during the first quarter of 2014. Accordingly, we incurred certain costs including those associated with the preliminary project analysis, data conversion from our legacy systems, backfill labor and end-user training that were not subject to capitalization. Restructuring charges during the 2012 period include employee termination benefits and a provision for lease costs attributable to exit activities in connection with the sale of our Appalachian assets.

Exploration

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
Unproved leasehold amortization	$ 17,451	$ 32,634	$ 15,183	47 %
Geological and geophysical costs	2,882	816	(2,066)	NM
Other, primarily delay rentals	661	642	(19)	(3)%
	$ 20,994	$ 34,092	$ 13,098	38 %

Unproved leasehold amortization declined during 2013 as costs related to successful Eagle Ford Shale wells were transferred to proved properties. In addition, due to the significance of the unproved acreage acquired in the 2013 EF Acquisition, our unproved property in the Eagle Ford Shale is now considered a "significant leasehold" and is not subject to systematic amortization. For further discussion of this matter, see "Critical Accounting Estimates — Oil and Gas Properties." Geological and geophysical costs increased during 2013 due primarily to the purchase of certain seismic data for the South Texas region. Delay rentals decreased during 2013 due primarily to the sale of our Appalachian natural gas properties.

Depreciation, Depletion and Amortization (DD&A)

The following table sets forth the nature of the DD&A variances for the periods presented:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
DD&A expense	$ 245,594	$ 206,336	$ (39,258)	(19)%
DD&A rate ($/BOE)	$ 35.99	$ 31.68	$ (4.31)	(14)%
	Production	Rates	Total	
DD&A variance due to:	$ (9,789)	$ (29,469)	$ (39,258)	

The effect of higher overall production volumes and higher depletion rates associated with oil and NGL production were the primary factors attributable to the increase in DD&A. Our average DD&A rate increased due primarily to higher capitalized finding and development costs attributable to our drilling program in the Eagle Ford Shale as well as lower natural gas reserves due to revisions.

Impairments

The following table summarizes the impairments recorded for the periods presented:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
Oil and gas properties	$ 132,224	$ 103,417	$ (28,807)	(28)%
Other - tubular inventory and well materials	—	1,067	1,067	NM
	$ 132,224	$ 104,484	$ (27,740)	(27)%

In 2013, we recognized oil and gas asset impairments of $121.8 million in the Granite Wash in the Mid-Continent, $9.5 million in the Marcellus Shale in Pennsylvania and $0.9 million in the Selma Chalk in Mississippi, in each case due primarily to market declines in current and expected future commodity prices. In June 2012, we recognized a $28.4 million impairment of our Appalachian assets triggered by the expected disposition of those properties and a $75.0 million impairment of our Marcellus Shale assets due primarily to market declines in natural gas prices and the resultant reduction in proved natural gas reserves. We also recognized impairments of certain tubular inventory and well materials in 2012 due primarily to declines in asset quality.

Loss on Firm Transportation Commitment

We have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022. Subsequent to the sale of our natural gas assets in that region in 2012, we no longer have production to satisfy this commitment. As a result, we recorded a charge of $17.3 million in 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract. Accretion of this liability for 2013 and 2012 has been recorded as a component of Other revenues.

Interest Expense

The following table summarizes the components of our interest expense for the periods presented:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
Interest on borrowings and related fees	$ 80,263	$ 56,080	$ (24,183)	(43)%
Accretion of original issue discount	431	1,367	936	68 %
Amortization of debt issuance costs	3,413	2,695	(718)	(27)%
Capitalized interest	(5,266)	(803)	4,463	NM
	$ 78,841	$ 59,339	$ (19,502)	(33)%
Weighted-average debt outstanding	$ 1,022,337	$ 697,786	$ (324,551)	
Weighted-average interest rate	8.23%	8.62%		

Interest expense increased during 2013 due primarily to higher overall weighted-average debt outstanding and a larger proportion of fixed-rate debt with higher interest rates in the 2013 period as compared to a larger proportion of Revolver borrowings at lower variable interest rates in 2012. The increase was partially offset by higher capitalized interest resulting from the significant increase in the value of our proved undeveloped and unproved properties following the 2013 EF Acquisition. For further discussion of this matter, see “Critical Accounting Estimates — Oil and Gas Properties.”

Loss on Extinguishment of Debt

In May 2013, we completed the Tender Offer and the Redemption for all of our outstanding 2016 Senior Notes. We paid a total of $330.9 million including consent payments and accrued interest in connection with the Tender Offer and Redemption and recognized a loss on the extinguishment of debt of $29.2 million. The loss on extinguishment of debt included non-cash charges of $10.0 million attributable to the write-off of unamortized debt issuance costs and the remaining debt discount associated with the 2016 Senior Notes. When we entered into the Revolver in September 2012, we expensed issuance costs of $3.2 million attributable to our previous revolving credit facility.

Derivatives

The following table summarizes the components of our derivatives income for the periods presented:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
Oil and gas derivatives settled	$ (1,042)	$ 28,317	$ (29,359)	104 %
Oil and gas derivative (loss) gain	(19,810)	6,464	(26,274)	(406)%
Interest rate swap gain	—	1,406	(1,406)	(100)%
	$ (20,852)	$ 36,187	$ (57,039)	(158)%

We paid net cash settlements of $1.0 million, all of which were attributable to commodity derivatives, during 2013 and $29.7 million, including $1.2 million attributable to the termination of an interest rate swap agreement, during 2012. The loss in the 2013 period is due primarily to period-end oil prices exceeding hedged prices as well as a substantially lower volume of natural gas production being hedged during 2013 period as compared to 2012.

Income Taxes

	Year Ended December 31, 2013	Year Ended December 31, 2012	Favorable (Unfavorable)	% Change
Income tax benefit	$ 77,696	$ 68,702	$ 8,994	13%
Effective tax benefit rate	35.2%	39.6%		

Due to the operating losses incurred, we recognized an income tax benefit during both periods. The effective tax benefit rate for 2013 includes a deferred tax asset valuation allowance for all current state net operating losses. The benefit rate for 2012 included a deferred tax asset valuation allowance related to the inability to recognize tax benefits for certain state net operating losses.

Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

Production

The following tables set forth a summary of our total and daily production volumes by product and geographic region for the periods presented:

Crude Oil	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
South Texas	1,959.6	751.2	1,208.4	5,354.0	2,058.1	3,295.9	NM
East Texas	71.1	117.5	(46.4)	194.2	321.9	(127.7)	(39)%
Mid-Continent	206.2	395.1	(188.9)	563.3	1,082.6	(519.3)	(48)%
Mississippi	14.1	18.9	(4.8)	38.6	51.7	(13.1)	(25)%
Appalachia	1.0	0.5	0.5	2.6	1.3	1.3	100 %
	2,251.9	1,283.2	968.8	6,152.6	3,515.5	2,637.1	75 %

NGLs	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
	(MBbl)			(Bbl per day)			
Texas							
South Texas	205.2	54.9	150.3	560.8	150.3	410.5	NM
East Texas	280.7	440.3	(159.6)	767.0	1,206.3	(439.3)	(36)%
Mid-Continent	397.2	411.1	(13.9)	1,085.4	1,126.4	(41.0)	(3)%
Mississippi	—	—	—	—	—	—	NM
Appalachia	0.8	0.9	(0.1)	2.1	2.5	(0.4)	(11)%
	884.0	907.2	(23.3)	2,415.3	2,485.5	(70.2)	(3)%

Natural Gas	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
	(MMcf)			(MMcf per day)			
Texas							
South Texas	1,015	277	738	2.8	0.8	2.0	NM
East Texas	5,909	9,393	(3,484)	16.1	25.7	(9.6)	(37)%
Mid-Continent	3,646	8,244	(4,598)	10.0	22.6	(12.6)	(56)%
Mississippi	4,997	6,441	(1,444)	13.7	17.6	(3.9)	(22)%
Appalachia	4,695	9,055	(4,360)	12.8	24.8	(12.0)	(48)%
	20,261	33,410	(13,148)	55.4	91.5	(36.1)	(39)%

Combined Total	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
	(MBOE)			(BOE per day)			
Texas							
South Texas	2,334	852	1,482	6,377	2,335	4,042	NM
East Texas	1,337	2,123	(786)	3,652	5,817	(2,165)	(37)%
Mid-Continent	1,211	2,180	(969)	3,309	5,973	(2,664)	(44)%
Mississippi	847	1,092	(245)	2,314	2,993	(679)	(22)%
Appalachia[1]	784	1,511	(727)	2,143	4,139	(1,996)	(48)%
	6,513	7,759	(1,245)	17,795	21,257	(3,462)	(16)%

[1] Subsequent to the sale of our Appalachian natural gas properties in July 2012, our remaining production from this region is provided by 3 gross (3.0 net) wells in the Marcellus Shale.

The decline in total production during 2012 compared to 2011 was due primarily to natural production declines as well as the effect of the sale of our Appalachian and Arkoma Basin natural gas properties in July 2012 and August 2011, respectively. The effect of the sale of the Appalachian properties was approximately 4.4 Bcfe (700 MBOE) and the Arkoma Basin properties was approximately 2.0 Bcfe (333 MBOE). The natural declines in production from our remaining natural gas properties were partially offset by an increase in oil, NGL and natural gas production attributable to our drilling activity in the Eagle Ford Shale. Approximately 48% of total production in 2012 was attributable to oil and NGLs, which represents an increase of approximately 43% over the previous year. During 2012, our Eagle Ford Shale production of 2,334 MBOE represented approximately 36% of our total production, which represents an increase of approximately 25% over the previous year.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product and geographic region for the periods presented:

Crude Oil	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2012	**2011**	**(Unfavorable)**	**2012**	**2011**	**(Unfavorable)**
				($ per Bbl)		
Texas						
South Texas	$ 202,479	$ 70,399	$ 132,080	$ 103.33	$ 93.72	9.61
East Texas	6,862	11,074	(4,212)	96.55	94.24	2.31
Mid-Continent	18,667	36,145	(17,478)	90.55	91.48	(0.93)
Mississippi	1,477	1,924	(447)	104.66	102.05	2.61
Appalachia	87	40	47	91.29	84.21	7.08
	$ 229,572	$ 119,582	$ 109,990	$ 101.95	$ 93.19	$ 8.76

NGLs	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2012	**2011**	**(Unfavorable)**	**2012**	**2011**	**(Unfavorable)**
				($ per Bbl)		
Texas						
South Texas	$ 6,451	$ 2,817	$ 3,634	$ 31.43	$ 51.33	$ (19.90)
East Texas	10,195	21,936	(11,741)	36.32	49.82	(13.50)
Mid-Continent	14,365	18,595	(4,230)	36.16	45.23	(9.07)
Appalachia	—	—	—	—	—	—
Mississippi	40	46	(6)	51.61	50.94	0.67
	$ 31,051	$ 43,394	$ (12,343)	$ 35.13	$ 47.83	$ (12.70)

Natural Gas	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2012	**2011**	**(Unfavorable)**	**2012**	**2011**	**(Unfavorable)**
				($ per Mcf)		
Texas						
South Texas	$ 2,593	$ 1,015	$ 1,578	$ 2.56	$ 3.66	$ (1.10)
East Texas	13,607	37,057	(23,450)	2.30	3.95	(1.65)
Mid-Continent	7,920	35,315	(27,395)	2.17	4.28	(2.11)
Mississippi	14,387	27,047	(12,660)	2.88	4.20	(1.32)
Appalachia	11,354	36,636	(25,282)	2.42	4.05	(1.63)
	$ 49,861	$ 137,070	$ (87,209)	$ 2.46	$ 4.10	$ (1.64)

Combined Total	**Year Ended December 31,**		**Favorable**	**Year Ended December 31,**		**Favorable**
	2012	**2011**	**(Unfavorable)**	**2012**	**2011**	**(Unfavorable)**
				($ per BOE)		
Texas						
South Texas	$ 211,523	$ 74,231	$ 137,292	$ 90.63	$ 87.10	$ 3.53
East Texas	30,664	70,067	(39,403)	22.94	33.00	(10.06)
Mid-Continent	40,952	90,055	(49,103)	33.81	41.31	(7.50)
Mississippi	15,864	28,971	(13,107)	18.73	26.52	(7.79)
Appalachia	11,481	36,722	(25,241)	14.64	24.31	(9.67)
	$ 310,484	$ 300,046	$ 10,438	$ 47.67	$ 38.67	$ 9.00

As illustrated below, higher oil production volume coupled with improved oil prices were the significant factors for increasing revenues. The increase was partially offset by lower natural gas and NGL production volumes and prices. Included in the price variance for natural gas was approximately $0.7 million of unfavorable adjustments attributable to the change in prices associated with gas imbalances due to us from partners in the Mid-Continent region.

The following table provides an analysis of the change in our revenues for 2012 as compared to 2011.

	Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ 90,274	$ 19,716	$ 109,990
NGL	(1,110)	(11,233)	(12,343)
Natural gas	(53,946)	(33,263)	(87,209)
	$ 35,218	$ (24,780)	$ 10,438

Effects of Derivatives

In 2012 and 2011, we received $28.3 million and $23.6 million, respectively, in cash settlements of oil and gas derivatives. The following table reconciles crude oil and natural gas revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Crude oil revenues as reported	$ 229,572	$ 119,582	$ 109,990	92 %
Cash settlements on crude oil derivatives	8,428	1,404	7,024	(500)%
	$ 238,000	$ 120,986	$ 117,014	97 %
Crude oil prices per Bbl, as reported	$ 101.95	$ 93.19	$ 8.76	9 %
Cash settlements on crude oil derivatives per Bbl	3.74	1.09	2.65	(243)%
	$ 105.69	$ 94.28	$ 11.41	12 %
Natural gas revenues as reported	$ 49,861	$ 137,070	$ (87,209)	(64)%
Cash settlements on natural gas derivatives	19,890	22,158	(2,268)	(10)%
Natural gas revenues adjusted for derivatives	$ 69,751	$ 159,228	$ (89,477)	(56)%
Natural gas prices per Mcf, as reported	$ 2.46	$ 4.10	$ (1.64)	(40)%
Cash settlements on natural gas derivatives per Mcf	0.98	0.66	0.32	48 %
	$ 3.44	$ 4.76	$ (1.32)	(28)%

Gain on Sales of Property and Equipment

In 2012, we recognized a gain of $3.3 million attributable to the sale of substantially all of our Appalachian natural gas assets for proceeds of $95.7 million, net of transaction costs. In 2011, we sold approximately 2,700 net undeveloped acres in Butler and Armstrong counties in Pennsylvania for proceeds of $8.1 million, net of transaction costs, and recognized a gain of $3.3 million. We also recognized a gain of $0.6 million in 2012 attributable to the sale of our remaining undeveloped acreage in those counties. In addition, we recognized several individually insignificant gains on the sale of property, equipment, tubular inventory and well material during both periods.

Production and Lifting Costs

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Lease operating	$ 31,266	$ 36,988	$ 5,722	15 %
Per unit of production ($/BOE)	$ 4.80	$ 4.77	$ (0.03)	(1)%

Lease operating expense decreased on an absolute basis during 2012 due primarily to the effect of the sale of our higher-cost Appalachian and Arkoma Basin natural gas properties. In addition to the effect of property sales, we incurred lower repair and maintenance expenses and lower compression costs during 2012. Cost decreases were partially offset by higher environmental and regulatory compliance, chemical treatment, field contracting and well tending costs attributable to our significantly expanded oil drilling program.

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Gathering, processing and transportation	$ 14,196	$ 15,157	$ 961	6 %
Per unit production ($/BOE)	$ 2.18	$ 1.95	$ (0.23)	(12)%

Gathering, processing and transportation charges decreased on an absolute basis during 2012 due primarily to the effect of the sale of our Appalachian and Arkoma Basin natural gas properties, partially offset by higher processing costs related to increased natural gas production in the Eagle Ford Shale as well as higher transportation costs in the Appalachian region in 2012 for periods prior to the sale.

Production and Ad Valorem Taxes

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Production/severance taxes	$ 7,534	$ 11,086	$ 3,552	32 %
Ad valorem taxes	3,100	2,604	(496)	(19)%
	$ 10,634	$ 13,690	$ 3,056	22 %
Per unit production ($/BOE)	$ 1.63	$ 1.76	$ 0.13	7 %
Production/severance tax rate as a percent of product revenue	2.4%	3.7%		

Production and ad valorem taxes decreased during 2012 due primarily to the recognition of Oklahoma severance tax rebates of $2.8 million attributable to horizontal and ultra-deep wells for the period of July 1, 2009 through June 30, 2011. Reductions were also recognized for production taxes on certain Texas wells in 2012 and for a property tax recovery attributable to West Virginia wells in 2011. Production taxes also decreased due to the Appalachian and Arkoma Basin natural gas properties sales as well as lower overall natural gas volumes and prices in 2012 as compared to 2011.

General and Administrative

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Recurring general and administrative expenses	$ 37,547	$ 38,547	$ 1,000	3 %
Share-based compensation (liability-classified)	714	—	(714)	NM
Share-based compensation (equity-classified)	6,347	7,430	1,083	15 %
Restructuring expenses	1,292	2,351	1,059	45 %
	$ 45,900	$ 48,328	$ 2,428	5 %
Per unit of production ($/BOE)	$ 7.05	$ 6.23	$ (0.82)	(13)%
Per unit of production excluding share-based compensation,				
acquisition transaction costs and restructuring charges ($/BOE)	$ 5.87	$ 4.97	$ (0.90)	(18)%

Recurring general and administrative expenses decreased due to reduced headcount and lower support costs following the sale of our Appalachian and Arkoma Basin natural gas properties. Liability-classified share-based compensation is attributable to our PBRSUs, which were issued for the first time in 2012. The 2012 grant of PBRSUs are payable in cash in 2015 upon achievement of specified market-based performance metrics. Equity-classified share-based compensation attributable to stock options and restricted stock units decreased during 2012 due primarily to a lower number of awards granted. Restructuring expenses for both the 2012 and 2011 periods include employee termination benefits and office relocation costs. The 2012 charge includes a provision for lease costs associated with the closing of our Canonsburg, Pennsylvania office, partially offset by a favorable adjustment to the lease obligation for our former Tulsa, Oklahoma office due to a change in estimated sub-lease rental income.

Exploration

The following table sets forth the components of exploration expenses for the periods presented:

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Unproved leasehold amortization	$ 32,634	$ 42,076	$ 9,442	22%
Geological and geophysical costs	816	11,202	10,386	93%
Dry hole costs	—	18,864	18,864	NM
Drilling rig standby charges	—	4,620	4,620	NM
Other, primarily delay rentals	642	2,181	1,539	71%
	$ 34,092	$ 78,943	$ 44,851	57%

Unproved leasehold amortization declined during 2012 as costs related to successful Eagle Ford Shale wells were transferred to proved properties. Geological and geophysical costs decreased during 2012 because our efforts in 2012 were concentrated on development drilling in the Eagle Ford Shale whereas in 2011 we conducted exploratory prospect activities in multiple areas. Dry hole costs in 2011 related to several unsuccessful wells in the Mid-Continent region. We also recorded drilling rig standby charges in 2011 in connection with the suspension of our exploratory drilling program in the Marcellus Shale.

Depreciation, Depletion and Amortization

The following tables set forth the nature of the DD&A variances for the periods presented:

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
DD&A expense	$ 206,336	$ 162,534	$ (43,802)	(27)%
DD&A rate ($/BOE)	$ 31.68	$ 20.95	$ (10.73)	(51)%

	Production	Rates	Total
DD&A variance due to:	$ 26,103	$ (69,905)	$ (43,802)

The effect of lower overall production volumes on DD&A was more than offset by higher depletion rates associated with oil and NGL production. Our average DD&A rate increased due primarily to higher capitalized finding and development costs attributable to our drilling program in the Eagle Ford Shale as well as lower natural gas reserves due to revisions.

Impairments

The following table summarizes the impairments recorded for the periods presented:

	Year Ended December 31, 2012	Year Ended December 31, 2011	Favorable (Unfavorable)	% Change
Oil and gas properties	$ 103,417	$ 104,688	$ 1,271	1%
Other - tubular inventory and well materials	1,067	—	(1,067)	NM
	$ 104,484	$ 104,688	$ 204	—%

In 2012, we recognized a $28.4 million impairment of our Appalachian natural gas assets triggered by the expected disposition of those properties, and a $75.0 million impairment of our Marcellus Shale assets due primarily to market declines in natural gas prices and the resultant reduction in proved natural gas reserves. In 2012, we also recognized an impairment of certain tubular inventory and well materials triggered primarily by declines in asset quality. In 2011, we recognized an impairment of our Arkoma Basin natural gas assets for $71.1 million, which was triggered by the expected disposition of those properties. Also during 2011, we recognized impairments of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $6.8 million, in each case due primarily to market declines in natural gas prices.

Loss on Firm Transportation Commitment

We have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the sale of our Appalachian natural gas assets in 2012, we no longer have production to satisfy this commitment. Accordingly, we recorded a charge of $17.3 million in 2012 representing the liability for estimated discounted future net cash outflows over the remaining term of the contract.

Other Operating Expense

During 2011, we recorded a reserve of $0.2 million for litigation attributable to properties that were previously sold. This matter was ultimately settled in January 2012 for the reserved amount. In addition, we wrote down certain gas imbalance assets that originated in prior years due to lower settlement rates.

Interest Expense

The following table summarizes the components of our total interest expense for the periods presented:

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Interest on borrowings and related fees	$ 56,080	$ 51,392	$ (4,688)	(9)%
Accretion of original issue discount	1,367	3,427	2,060	60 %
Amortization of debt issuance costs	2,695	3,380	685	20 %
Capitalized interest	(803)	(1,983)	(1,180)	60 %
	$ 59,339	$ 56,216	$ (3,123)	(6)%
Weighted-average debt outstanding	$ 697,786	$ 590,512		
Weighted-average interest rate	8.6%	9.9%		

The issuance of our 7.25% Senior Notes due 2019, or the 2019 Senior Notes, and borrowings under the Revolver, partially offset by the repurchase of approximately 98% of our 4.50% Convertible Senior Subordinated Notes due 2012, or the Convertible Notes, with an effective interest rate of 8.5%, resulted in an approximate $107 million higher weighted-average balance of debt outstanding during 2012 compared to 2011. Accordingly, interest expense increased due to a higher average outstanding principal balance despite lower effective interest rates attributable to the 2019 Senior Notes and the Revolver. Capitalized interest was lower during 2012 due to lower carrying values on eligible capital projects.

Loss on Extinguishment of Debt

When we entered into the Revolver in September 2012, we expensed issuance costs of $3.2 million attributable to our previous revolving credit facility. During 2011, we expensed $1.2 million attributable to a change in the composition of the bank syndicate for our previous revolving credit facility. The repurchase in April 2011 of approximately 98% of the Convertible Notes resulted in a loss on extinguishment of debt of $24.2 million.

Derivatives

The following table summarizes the components of our derivatives income for the periods presented:

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Oil and gas derivatives settled	$ 28,317	$ 23,562	$ 4,755	20 %
Oil and gas derivative gain (loss)	6,464	(9,140)	15,604	(171)%
Interest rate swap settled	—	3,818	(3,818)	(100)%
Interest rate swap gain (loss)	1,406	(2,589)	3,995	(154)%
	$ 36,187	$ 15,651	$ 20,536	131 %

We received cash settlements of $29.7 million during 2012 and $27.4 million during 2011. The cash settlements in 2012 and 2011 included $1.2 million and $2.9 million attributable to the termination of our interest rate swap agreements during those periods. The increase in the commodity derivative gain was due primarily to oil and natural gas prices declining below our hedged prices.

Income Taxes

	Year Ended December 31,		Favorable	
	2012	2011	(Unfavorable)	% Change
Income tax benefit	$ 68,702	$ 88,155	$ (19,453)	(22)%
Effective tax benefit rate	39.6%	39.9%		

Due to the operating losses incurred, we recognized an income tax benefit during both periods. In addition, the effective tax rates for 2012 and 2011 included a deferred tax asset valuation allowance related to the inability to recognize tax benefits for certain state net operating losses.

Financial Condition

Liquidity

Our primary sources of liquidity include cash from operating activities, borrowings under our Revolver, proceeds from the sales of non-core assets and, when appropriate, proceeds from capital market transactions including the sale of debt and equity securities. Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGLs and natural gas products as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among others.

Our business plan contemplates capital expenditures in excess of our projected cash from operating activities for 2014 and 2015. Subject to the variability of commodity prices and production that impact our cash from operating activities, anticipated timing of our capital projects and unanticipated expenditures such as acquisitions, we plan to fund our 2014 capital program with cash from operating activities, borrowings under the Revolver, proceeds from the sales of non-core assets and supplemental issues of debt and equity, if appropriate. We have no debt maturities until September 2017 when the Revolver matures. We believe that our cash from operating activities, borrowing capacity under the Revolver and the projected proceeds from the sales of non-core assets will be sufficient to meet our debt service, preferred stock dividend and working capital requirements as well as our anticipated capital expenditures.

Capital Resources

In 2014, we anticipate making capital expenditures, excluding any acquisitions, of up to approximately $640 million. Based on expenditures to date and forecasted activity for the remainder of 2014, we expect to allocate 98 percent of our capital expenditures to the Eagle Ford Shale. This allocation includes approximately 85 percent for drilling and completions, 11 percent for leasehold acquisition and four percent for pipeline, gathering, seismic, facilities and other projects. The total forecasted activity assumes a drilling program utilizing a total of up to six operated drilling rigs in the Eagle Ford Shale. For a detailed analysis of our historical capital expenditures, see the *Cash Flows* discussion that follows. We continually review drilling and other capital expenditure plans and may change the amount we spend in any area based on available opportunities, industry conditions, cash from operating activities and the overall availability of capital.

Cash From Operating Activities. Our cash from operating activities is subject to significant volatility due primarily to changes in commodity prices for our products and variations in our production. Accordingly, we actively manage the exposure of our revenues to commodity price fluctuations by hedging the commodity price risk for a portion of our expected production, typically through the use of collar, swap and swaption contracts. The level of our hedging activity and duration of the instruments employed depend on our cash flow at risk, available hedge prices and our operating strategy. During 2013, our commodity derivatives portfolio resulted in $2.6 million of net cash payments related to higher than anticipated prices received for our oil production and provided $1.6 million of net cash receipts attributable to lower than anticipated prices received for our natural gas production.

We have hedged approximately 70 percent of our estimated crude oil production for the first half of 2014 and approximately 65 percent for the second half of 2014 at a weighted-average floor price of $93.55 per barrel. In addition, we have hedged approximately 40 percent of our estimated natural gas production through the third quarter of 2014 at a weighted-average floor price of $4.13 per MMBtu and approximately 15 percent for the 2014 - 2015 winter at a weighted-average floor price of $4.50 per MMBtu.

In addition to recurring payments for production and lifting costs, production and ad valorem taxes and general and administrative costs, our most significant operating cash outflows are attributable to debt service costs. Historically, we have also made operating cash payments with respect to restructuring programs and certain costs for other transactions, including the 2013 EF Acquisition. For a detailed analysis of our historical cash flows from operating activities, see the *Cash Flows* discussion that follows.

Revolver Borrowings. The Revolver provides for a $400 million revolving commitment and has a borrowing base of $425 million. The Revolver has an accordion feature that allows us to increase the commitment by up to an additional $200 million upon receiving additional commitments from one or more lenders. The Revolver also includes a $20 million sublimit for the issuance of letters of credit. The Revolver is governed by a borrowing base calculation, which is redetermined semi-annually, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The next semi-annual redetermination is scheduled for May 2014. The Revolver allows for the administrative agent to replace any lender who fails to approve a borrowing base increase approved by lenders representing two thirds of the aggregate commitment. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017.

We had letters of credit of $2.7 million outstanding as of December 31, 2013. As of December 31, 2013, our available borrowing capacity under the Revolver was $191.3 million. Excluding the impact of any potential asset sales, we anticipate our borrowing base to increase upon the next scheduled redetermination in May 2014 due to our expanded drilling activity in the Eagle Ford Shale.

For additional information regarding the terms and covenants associated with our Revolver, see the *Capitalization* discussion that follows. The following table summarizes our borrowing activity under the Revolver during the periods presented:

	Borrowings Outstanding		
	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended December 31, 2013	$ 172,011	$ 206,000	2.0124%
Year ended December 31, 2013	$ 89,389	$ 206,000	1.9339%

Proceeds from Asset Sales. In January 2014, we sold our natural gas gathering assets in South Texas for proceeds of approximately $94 million, net to our working interest, and we recently began a process to sell our Granite Wash and Selma Chalk assets. For a detailed analysis of our historical proceeds from asset sales, see the *Cash Flows* discussion that follows.

Capital Market Transactions. From time-to-time and under market conditions that we believe are favorable to us, we will consider capital market transactions, including the offering of debt and equity securities. Historically, we have entered into such transactions generally to facilitate certain transactions, including the 2013 EF Acquisition, and to pursue opportunities to adjust our total capitalization. For a detailed analysis of our historical proceeds from capital market transactions, see the *Cash Flows* discussion that follows.

Cash Flows

The following table summarizes our cash flows for the periods presented:

	Year Ended December 31,		
	2013	2012	Variance
Cash flows from operating activities			
Operating cash flows, net	$ 314,424	$ 217,688	$ 96,736
Working capital changes, net	19,120	20,157	(1,037)
Commodity derivative settlements (paid) received, net:			—
Crude oil	(2,624)	8,427	(11,051)
Natural gas	1,582	19,890	(18,308)
Interest payments, net of amounts capitalized	(65,107)	(54,808)	(10,299)
Income tax refunds received, net	—	32,603	(32,603)
2013 EF Acquisition transaction and integration costs paid	(3,029)	—	(3,029)
Restructuring and exit costs paid	(2,854)	(2,499)	(355)
Net cash provided by operating activities	261,512	241,458	20,054
Cash flows from investing activities			
2013 EF Acquisition and settlement of related obligations, net	(380,694)	—	(380,694)
Capital expenditures - property and equipment	(504,203)	(370,907)	(133,296)
Proceeds from sales of assets and other, net	(54)	96,899	(96,953)
Net cash used in investing activities	(884,951)	(274,008)	(610,943)
Cash flows from financing activities			
Proceeds from the issuance of preferred stock, net	—	110,337	(110,337)
Proceeds from the issuance of common stock, net	—	43,474	(43,474)
Proceeds from the issuance of senior notes	775,000	—	775,000
Retirement of senior notes	(319,090)	(4,915)	(314,175)
Proceeds from revolving credit facility borrowings, net	206,000	(99,000)	305,000
Debt issuance costs paid	(25,634)	(2,032)	(23,602)
Dividends paid on preferred and common stock	(6,862)	(5,176)	(1,686)
Other, net	(151)	—	(151)
Net cash provided by financing activities	629,263	42,688	586,575
Net increase in cash and cash equivalents	$ 5,824	$ 10,138	$ (4,314)

Cash Flows From Operating Activities. Higher realized cash flows from higher operating margin oil and NGL operations resulted in an increase in our cash flows from operating activities during 2013 as compared to 2012. When comparing 2013 and 2012, the higher realized cash flows were partially offset by (i) higher amounts paid for interest during the 2013 period due to higher average outstanding Revolver balances and a higher level of outstanding senior indebtedness, (ii) the receipt of a significant federal income tax refund during 2012, (iii) the realization of substantially lower net settlements from our commodity derivatives portfolio during 2013 due primarily to realized crude oil prices exceeding hedged prices as well as a significantly lower volume of natural gas production subject to hedges, (iv) the payment of transaction costs, including advisory, legal, due diligence and other professional fees in connection with the 2013 EF Acquisition during 2013 and (v) higher restructuring and exit costs payments during 2013 due primarily to ongoing contractual payments for firm transportation capacity in the Appalachian region.

Cash Flows From Investing Activities. We paid approximately $380 million for the 2013 EF Acquisition. This amount includes: (i) approximately $379 million, including approximately $19 million of initial purchase price adjustments, paid to the seller at settlement, (ii) approximately $22 million, net paid subsequent to the Acquisition Date to settle obligations assumed in the 2013 EF Acquisition and (iii) the receipt of approximately $21 million of proceeds received from certain of our joint interest partners upon the exercise of their preferential rights with respect to the 2013 EF Acquisition.

Capital expenditures were substantially higher during 2013 as compared to 2012 due primarily to a higher level of drilling activity and facilities construction attributable to the expansion of our operations in the Eagle Ford Shale.

The following table sets forth costs related to our capital expenditure program for the periods presented:

	Year Ended December 31,	
	2013	2012
Oil and gas:		
Development drilling	$ 404,957	$ 287,363
Lease acquisitions and other land-related costs [1]	69,155	28,380
Pipeline, gathering facilities and other equipment	17,583	18,330
Exploration drilling	13,289	49,462
Geological and geophysical (seismic) costs	2,882	816
	507,866	384,351
Other - Corporate [2]	2,370	629
Total capital program costs	$ 510,236	$ 384,980

[1] Includes site-preparation and other pre-drilling costs.
[2] Includes approximately $2 million in 2013 for an integrated enterprise-wide information technology platform.

The following table reconciles the total costs of our capital expenditure program with the net cash paid for capital expenditures for additions to property and equipment as reported in our Consolidated Statements of Cash Flows for the periods presented:

	Year Ended December 31,	
	2013	2012
Total capital program costs	$ 510,236	$ 384,980
Increase in accrued capitalized costs	(6,355)	(4,550)
Less:		
Exploration expenses charged to operations:		
Geological and geophysical (seismic)	(2,882)	(816)
Other, primarily delay rentals	(662)	(646)
Transfers from tubular inventory and well materials	(2,471)	(13,359)
Add:		
Tubular inventory and well materials purchased in advance of drilling	1,071	4,495
Capitalized interest	5,266	803
Total cash paid for capital expenditures	$ 504,203	$ 370,907

We received proceeds, net of related costs, and other settlements from the disposition of certain non-core properties and other assets during both 2013 and 2012 as follows:

	Year Ended December 31,	
	2013	2012
Appalachian natural gas properties, net	$ 62	$ 95,687
Other property sales, net	23	1,482
Tubular inventory and well materials, net	399	96
Proceeds from the sales of assets, net	484	97,265
Payments of post-closing adjustments attributable to sales of assets	(538)	(546)
Other, net	—	180
	$ (54)	$ 96,899

Cash Flows From Financing Activities. In April 2013, we issued the the 2020 Senior Notes which were used to fund the 2013 EF Acquisition and a portion of the Tender Offer and the Redemption of our outstanding 2016 Senior Notes. We incurred and paid costs associated with the issuance of the 2020 Senior Notes as well as costs associated with an amendment to our Revolver. Cash flows from financing activities for 2013 include net borrowings under the Revolver while the 2012 period includes net repayments under the Revolver which were funded by the proceeds from the sale of our Appalachian natural gas assets and a federal income tax refund. Dividends paid in the 2013 period were attributable to our 6% Series A Convertible Perpetual Preferred Stock, or the 6% Preferred Stock, and dividends paid in 2012 were attributable to our common stock.

Capitalization

The following table summarizes our total capitalization as of the dates presented:

	As of December 31,	
	2013	2012
Revolving credit facility	$ 206,000	$ —
Senior notes due 2016 [1]	—	294,759
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	—
Total debt	1,281,000	594,759
Shareholders' equity [2]	788,804	895,116
	$ 2,069,804	$ 1,489,875
Debt as a % of total capitalization	62%	40%

[1] The 2016 Senior Notes were retired in 2013 in connection with the Tender Offer and the Redemption.

[2] Includes 11,500 shares of the 6% Preferred Stock which has a liquidation preference of $10,000 per share, or $115 million.

Revolving Credit Facility. Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from LIBOR, as adjusted for statutory reserve requirements for Eurocurrency liabilities, or Adjusted LIBOR, plus an applicable margin (ranging from 1.500% to 2.500%) or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0%, and, in each case, plus an applicable margin (ranging from 0.500% to 1.500%). In each case, the applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. As of December 31, 2013, the actual interest rate applicable to the Revolver was 2.1875% which is derived from an Adjusted LIBOR rate of 0.1875% plus an applicable margin of 2.0%. Commitment fees are charged at 0.375% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2013, commitment fees are charged at a rate of 0.500%.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries, or the Guarantor Subsidiaries. The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

2019 Senior Notes. The 7.25% Senior Notes due 2019, or the 2019 Senior Notes, which were issued at par in April 2011, bear interest at an annual rate of 7.25% payable on April 15 and October 15 of each year. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

2020 Senior Notes. The 2020 Senior Notes, which were issued at par in April 2013, bear interest at an annual rate of 8.5% payable on May 1 and November 1 of each year. The 2020 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The 2020 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

6% Preferred Stock. The annual dividend on each share of the 6% Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on January 15, April 15, July 15 and October 15 of each year. We may, at our option, pay dividends in cash, common stock or a combination thereof.

Each share of the 6% Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $6.00 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the 6% Preferred Stock. The initial conversion price represents a premium of 20 percent relative to the 2012 common stock offering price of $5.00 per share. The 6% Preferred Stock is not redeemable by us or the holders at any time. At any time on or after October 15, 2017, we may, at our option, cause all outstanding shares of the 6% Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the 6% Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

Covenant Compliance. The Revolver and the indentures associated with our senior notes require us to maintain certain financial and non-financial covenants. These covenants impose limitations on our ability to pay dividends as well as our ability to incur indebtedness, grant liens, make certain loans, acquisitions and investments, make any material change to the nature of our business, or enter into a merger or sale of our assets, including the sale or transfer of interests in our subsidiaries, among other requirements. As of December 31, 2013 and through the date upon which our Consolidated Financial Statements were issued, we were in compliance with these covenants.

In the event that we would be in default of a covenant under the Revolver, we could request a waiver of the covenant from our bank group. Should the banks deny our request to waive the covenant requirement, the outstanding borrowings under the Revolver would become payable on demand and would be reclassified as a component of current liabilities on our Consolidated Balance Sheets.

The Revolver requires us to maintain certain financial covenants as follows:

- Total debt to EBITDAX, each as defined in the Revolver, for any four consecutive quarters may not exceed 4.5 to 1.0 for periods through June 30, 2014, 4.25 to 1.0 for periods through December 31, 2014 and 4.0 to 1.0 for periods through maturity in 2017. EBITDAX, which is a non-GAAP measure, generally means net income plus interest expense, taxes, depreciation, depletion and amortization expenses, exploration expenses, impairments and other non-cash charges or losses.
- The current ratio, as of the last day of any quarter, may not be less than 1.0 to 1.0. The current ratio is generally defined as current assets to current liabilities. Current assets and current liabilities attributable to derivative instruments are excluded. In addition, current assets include the amount of any unused commitment under the Revolver.

The indentures for our senior notes include an incurrence test which is determined by an interest coverage ratio, as defined in the indentures. The interest coverage ratio may not be less than 2.25 times consolidated EBITDAX, a non-GAAP measure.

The following table summarizes the actual results of our financial covenant compliance under the Revolver and senior note indentures as of and for the period ended December 31, 2013:

Description of Covenant	Required Covenant	Actual Results
Total debt to EBITDAX	< 4.50 to 1	3.7 to 1
Current ratio	> 1.00 to 1	1.7 to 1
Interest coverage	> 2.25 to 1	3.5 to 1

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2013, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, well drilling commitments, hydraulic fracturing service commitments, firm transportation agreements and letters of credit, all of which are customary in our business. See Contractual Obligations summarized below for more details related to the value of our off-balance sheet arrangements. We did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We are, therefore, not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2013:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Revolver [1]	$ 206,000	$ —	$ —	$ 206,000	$ —
Senior Notes due 2019 and 2020 [2]	1,075,000	—	—	—	1,075,000
Interest on long-term debt [3]	564,723	92,131	184,263	178,642	109,687
Operating leases [4]	7,393	1,884	3,510	1,318	681
Well drilling and completion commitments	93,013	88,398	4,615	—	—
Firm transportation commitments [5]	42,201	4,788	8,670	7,762	20,981
Derivatives [6]	10,141	10,141	—	—	—
Asset retirement obligations [7]	22,217	—	—	—	22,217
Other commitments [8]	13,588	$ 4,021	$ 9,567	$ —	$ —
Total contractual obligations	$ 2,034,276	$ 201,363	$ 210,625	$ 393,722	$ 1,228,566

[1] Assumes that the amount outstanding of $206 million as of December 31, 2013 will remain outstanding until its maturity in 2017.

[2] Upon their maturities in April 2019 and May 2020, the principal amounts of $300 million and $775 million each will be due.

[3] Represents estimated interest payments that will be due under the Revolver, assuming the amount outstanding of $206 million as of December 31, 2013 will remain until its maturity in 2017, as well as contractual interest payments on the 2019 Senior Notes and the 2020 Senior Notes.

[4] Relates primarily to office and equipment leases.

[5] Includes $24.1 million of undiscounted payments attributable to a firm transportation obligation for which $16.0 million has been recognized on our Consolidated Balance Sheet as of December 31, 2013.

[6] Represents estimated payments that we will make resulting from commodity derivatives that are in a liability position as of December 31, 2013.

[7] Represents the undiscounted balance payable in periods more than five years in the future for which $6.4 million has been recognized on our Consolidated Balance Sheet as of December 31, 2013. While we anticipate making payments to settle asset retirement obligations during each of the next five years, none are currently required by contract to be made during this time frame.

[8] Represents all other significant obligations including minimum commitments under a natural gas gathering and compression service agreement and information technology licensing and service agreements, among others.

Critical Accounting Estimates

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. We consider the following to be the most critical accounting estimates requiring judgment of our management.

Oil and Gas Reserves

Estimates of our oil and gas reserves are the most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates, recoverability of historical cost investments and the fair value of properties acquired as well as those subject to potential impairments. There are many uncertainties inherent in estimating crude oil, NGL and natural gas reserve quantities, including projecting the total quantities in place, future production rates and the amount and timing of future development expenditures. In addition, reserve estimates of new discoveries are less precise than those of producing properties due to the lack of a production history. Accordingly, these estimates are subject to change as additional information becomes available.

There are several factors which could change the estimates of our oil and gas reserves. Significant rises or declines in commodity product prices could lead to changes in the amount of reserves as production activities become more or less economical. An additional factor that could result in a change of recorded reserves is the reservoir decline rates differing from those assumed when the reserves were initially recorded. Estimation of future production and development costs is also subject to change partially due to factors beyond our control, such as energy costs and inflation or deflation of oil field service costs.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to the necessary facilities or receiving to such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

We assess our proved oil and gas properties for impairment on a geographic basis, generally at the field level, based upon a periodic review of commodity prices and, when available, updated oil and gas reserve data. Generally, we compile updated oil and gas reserve data once during the calendar year and again at year-end on a more formal basis. The assessment is performed by comparing the carrying value of proved properties for each field to the undiscounted estimated future cash flows. Undiscounted estimated future cash flows are based on updated oil and gas reserve data, when available, and include the impact of risk-adjusted probable and possible reserves, future commodity prices, anticipated production and forecasted operating and capital expenditures. Commodity prices are estimated based on five-year NYMEX strip prices, adjusted accordingly for basis differentials and other factors consistent with management’s assumptions utilized for internal planning and budgeting purposes. If, based on the assessment, the carrying value of the proved properties exceeds the undiscounted estimated future cash flows, the cost of the proved properties are written down to fair value. In certain circumstances, significant management judgment is applied to consideration of the results of such assessment described above. Accordingly, it is possible that impairment would not be appropriate for certain properties that failed the objective assessment based on consideration of other factors, including the timeliness of reserve assignment, among others. Likewise, impairment may be appropriate for other properties that otherwise passed the objective assessment based on the trending of prices, lease expirations and future development plans.

A portion of the carrying value of our oil and gas properties is attributable to unproved properties. As of December 31, 2013, the costs attributable to unproved properties, net of accumulated amortization, were $101.5 million. Unproved properties whose acquisition costs are insignificant are amortized as a component of exploration expense in the aggregate over the lesser of five years or the average remaining lease term. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a stand-alone basis. As exploration work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

For the past several years, we have not had any unproved properties that were deemed significant as described above. Subsequent to the 2013 EF Acquisition our unproved properties in the Eagle Ford Shale are now considered significant and became subject to impairment on a stand-alone basis effective July 1, 2013. Furthermore, we anticipate transferring material amounts representing the cost of unproved leaseholds to proved properties in future periods as our activities in the Eagle Ford Shale continue to be successful. Accordingly, we anticipate that our future charges for unproved leasehold amortization will decline from historical levels.

Considering the magnitude of unproved and proved undeveloped properties acquired, the related indebtedness that we incurred to finance the 2013 EF Acquisition, and timing of the development plans that we have for the Eagle Ford Shale, we anticipate the capitalization of interest costs to increase substantially in future periods. In 2013, we capitalized $5.6 million of interest costs attributable to qualifying activities that are in process to bring our Eagle Ford Shale unproved and proved undeveloped properties into production.

Depreciation, Depletion and Amortization

We determine depreciation and depletion of oil and gas producing properties by the units-of-production method and these amounts could change with revisions to estimated proved recoverable reserves. We compute depreciation and amortization of other property and equipment using the straight-line balance method over the estimated useful life of each asset.

Derivative Activities

From time to time, we enter into derivative instruments to mitigate our exposure to crude oil and natural gas price volatility and interest rate fluctuations. The derivative financial instruments, which are placed with financial institutions that we believe are of acceptable credit risk, take the form of collars, swaps and swaptions, among others. All derivative instruments are recognized in our Consolidated Financial Statements at fair value with the changes recorded currently in earnings. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices and rates. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

Deferred Tax Asset Valuation Allowance

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that we were to determine that we would not be able to realize all or a part of our deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of our deferred tax assets is attributable to net operating losses in certain states. Estimates of future taxable income inherently reflect a significant degree of uncertainty. During the years ended December 31, 2012, 2011 and 2010, we increased the valuation allowance for our deferred tax assets due primarily to our inability to project sufficient future taxable income in certain states.

Share-Based Compensation

In May 2013 and February 2012, we granted PBRSUs to certain executive officers. Vested PBRSUs are payable in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

Because the PBRSUs are payable solely in cash, they are considered liability-classified awards and are included in the Other liabilities caption on our Condensed Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period based on the fair value derived from a Monte Carlo model and recognized based on the period of time that has elapsed during each of the individual performance periods. The Monte Carlo model is a binomial valuation model that requires significant judgment with respect to certain assumptions, including volatility, dividends and other factors. Due primarily to the sensitivity of certain model assumptions, as well as the inherent variability of modeling market-based performance over future periods, our compensation expense with respect to the PBRSUs can be volatile.

New Accounting Standards

Effective January 1, 2013, we adopted Accounting Standards Update No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*, or ASU 2013-02. The disclosures required by ASU 2013-02 are included in Note 13 to our Consolidated Financial Statements. The adoption of ASU 2013-02 did not have a significant impact on our Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

All of our long-term debt instruments, with the exception of the Revolver, have fixed interest rates. Accordingly, our interest rate risk is attributable to our borrowings under the Revolver, which is subject to variable interest rates. As of December 31, 2013, we had borrowings of $206 million under the Revolver at an interest rate of 2.1875%. Assuming a constant borrowing level of $206 million under the Revolver, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense of approximately $2.1 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars, swaps and swaptions) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of oil and natural gas. We have not typically entered into derivative instruments with respect to NGLs, although we may do so in the future.

As of December 31, 2013, we reported a commodity derivative asset of $5.4 million. The contracts associated with this position are with six counterparties, all of which are investment grade financial institutions, and are substantially concentrated with three of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We neither paid nor received collateral with respect to our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties. The maximum amount of loss due to credit risk if counterparties to our derivative asset positions fail to perform according to the terms of the contracts would be equal to the fair value of the contracts as of December 31, 2013.

During the year ended December 31, 2013, we reported net commodity derivative losses of $20.9 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 5 to our Consolidated Financial Statements for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as of December 31, 2013:

	Instrument	Average Volume Per Day	Weighted Average Price Floor/Swap	Weighted Average Price Ceiling	Fair Value Asset	Fair Value Liability
Crude Oil:		**(barrels)**	**($/barrel)**			
First quarter 2014	Collars	1,500	$ 93.33	$ 102.80	$ —	$ 28
Second quarter 2014	Collars	1,500	$ 93.33	$ 102.80	128	—
First quarter 2014	Swaps	8,500	$ 94.00		—	3,352
Second quarter 2014	Swaps	8,500	$ 94.00		—	2,280
Third quarter 2014	Swaps	9,000	$ 93.38		—	1,025
Fourth quarter 2014	Swaps	9,000	$ 93.38		607	—
First quarter 2015	Swaps	3,000	$ 91.92		88	—
Second quarter 2015	Swaps	3,000	$ 91.92		435	—
Third quarter 2015	Swaps	2,000	$ 91.48		410	—
Fourth quarter 2015	Swaps	2,000	$ 91.48		556	—
Natural Gas:		**(in MMBtu)**	**($/MMBtu)**			
First quarter 2014	Collars	5,000	$ 4.00	4.50	—	3
First quarter 2014	Swaps	10,000	$ 4.28		1	—
Second quarter 2014	Swaps	15,000	$ 4.10		—	1
Third quarter 2014	Swaps	15,000	$ 4.10		—	60
Fourth quarter 2014	Swaps	5,000	$ 4.50		125	—
First quarter 2015	Swaps	5,000	$ 4.50		64	—
Settlements to be paid in subsequent period					—	423

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying commodity prices. This illustration assumes that crude oil prices, natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of $10.00 per Barrel of Crude Oil or $1.00 per MMBtu of Natural Gas ($ in millions) Increase	Decrease
Effect on the fair value of crude oil derivatives	$ (41.9)	$ 40.8
Effect on the fair value of natural gas derivatives	$ (4.5)	$ 4.5
Effect on 2014 operating income, excluding crude oil derivatives	$ 51.2	$ (51.2)
Effect on 2014 operating income, excluding natural gas derivatives	$ 11.3	$ (11.3)

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2013. We also have audited Penn Virginia Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Penn Virginia Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Penn Virginia Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Penn Virginia Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Houston, Texas
February 24, 2014

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2013	**2012**	**2011**
Revenues			
Crude oil	$ 347,407	$ 229,572	$ 119,582
Natural gas liquids (NGLs)	30,748	31,051	43,394
Natural gas	52,538	49,861	137,070
Gain (loss) on sales of property and equipment, net	(266)	4,282	3,570
Other	1,041	2,383	2,389
Total revenues	431,468	317,149	306,005
Operating expenses			
Lease operating	35,461	31,266	36,988
Gathering, processing and transportation	12,839	14,196	15,157
Production and ad valorem taxes	22,404	10,634	13,690
General and administrative	53,998	45,900	48,328
Exploration	20,994	34,092	78,943
Depreciation, depletion and amortization	245,594	206,336	162,534
Impairments	132,224	104,484	104,688
Loss on firm transportation commitment	—	17,332	—
Other	—	—	1,096
Total operating expenses	523,514	464,240	461,424
Operating loss	(92,046)	(147,091)	(155,419)
Other income (expense)			
Interest expense	(78,841)	(59,339)	(56,216)
Loss on extinguishment of debt	(29,174)	(3,164)	(25,421)
Derivatives	(20,852)	36,187	15,651
Other	147	116	335
Loss before income taxes	(220,766)	(173,291)	(221,070)
Income tax benefit	77,696	68,702	88,155
Net loss	(143,070)	(104,589)	(132,915)
Preferred stock dividends	(6,900)	(1,687)	—
Net loss attributable to common shareholders	$ (149,970)	$ (106,276)	$ (132,915)
Net loss per share:			
Basic	$ (2.41)	$ (2.22)	$ (2.90)
Diluted	$ (2.41)	$ (2.22)	$ (2.90)
Weighted average shares outstanding - basic	62,335	47,919	45,784
Weighted average shares outstanding - diluted	62,335	47,919	45,784

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2013	**2012**	**2011**
Net loss	$ (143,070)	$ (104,589)	$ (132,915)
Other comprehensive income (loss):			
Change in pension and postretirement obligations, net of tax of $673 in 2013, $54 in 2012 and $(79) in 2011	1,249	102	(146)
	1,249	102	(146)
Comprehensive loss	$ (141,821)	$ (104,487)	$ (133,061)

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	As of December 31,	
	2013	**2012**
Assets		
Current assets		
Cash and cash equivalents	$ 23,474	$ 17,650
Accounts receivable, net of allowance for doubtful accounts	194,403	62,978
Derivative assets	3,830	11,292
Deferred income taxes	6,065	—
Other current assets	5,924	4,595
Total current assets	233,696	96,515
Property and equipment, net (successful efforts method)	2,237,304	1,723,359
Derivative assets	1,552	5,181
Other assets	34,535	17,934
Total assets	$ 2,507,087	$ 1,842,989
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 248,004	$ 111,655
Derivative liabilities	10,141	—
Deferred income taxes	—	370
Total current liabilities	258,145	112,025
Other liabilities	33,386	28,901
Derivative liabilities	—	1,421
Deferred income taxes	145,752	210,767
Long-term debt	1,281,000	594,759
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock of $100 par value – 100,000 shares authorized; 11,500 shares issued as of December 31, 2013 and December 31, 2012 with a redemption value of $10,000 per share	1,150	1,150
Common stock of $0.01 par value – 128,000,000 shares authorized; shares issued of 65,306,748 and 55,117,346 as of December 31, 2013 and December 31, 2012, respectively	466	364
Paid-in capital	891,351	849,046
Retained earnings (Accumulated deficit)	(104,180)	45,790
Deferred compensation obligation	2,792	3,111
Accumulated other comprehensive income (loss)	267	(982)
Treasury stock – 233,063 and 218,320 shares of common stock, at cost, as of December 31, 2013 and December 31, 2012, respectively	(3,042)	(3,363)
Total shareholders' equity	788,804	895,116
Total liabilities and shareholders' equity	$ 2,507,087	$ 1,842,989

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities			
Net loss	$ (143,070)	$ (104,589)	$ (132,915)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Loss on extinguishment of debt	29,174	3,144	22,456
Loss on firm transportation commitment	—	17,332	—
Depreciation, depletion and amortization	245,594	206,336	162,534
Impairments	132,224	104,484	104,688
Derivative contracts:			
Net losses (gains)	20,852	(36,187)	(15,651)
Cash settlements	(1,042)	29,723	27,380
Deferred income tax benefit	(77,696)	(68,676)	(85,501)
Loss (gain) on sales of assets, net	266	(4,282)	(2,474)
Non-cash exploration expense	17,451	32,634	60,940
Non-cash interest expense	3,844	4,062	6,807
Share-based compensation (equity-classified)	5,781	6,347	7,430
Other, net	1,971	1,004	275
Changes in operating assets and liabilities:			
Accounts receivable, net	(105,023)	9,907	(1,792)
Income taxes receivable and payable, net	—	31,439	(2,815)
Accounts payable and accrued expenses	129,670	9,710	(6,552)
Other assets and liabilities	1,516	(930)	(69)
Net cash provided by operating activities	261,512	241,458	144,741
Cash flows from investing activities			
Acquisition, net	(358,239)	—	—
Payments to settle working capital adjustments assumed in acquisition, net	(22,455)	—	—
Capital expenditures - property and equipment	(504,203)	(370,907)	(445,623)
Proceeds from sales of assets, net	(54)	96,719	39,368
Other, net	—	180	100
Net cash used in investing activities	(884,951)	(274,008)	(406,155)
Cash flows from financing activities			
Proceeds from the issuance of preferred stock, net	—	110,337	—
Proceeds from the issuance of common stock, net	—	43,474	—
Proceeds from the issuance of senior notes	775,000	—	300,000
Retirement of senior notes	(319,090)	(4,915)	(232,963)
Proceeds from revolving credit facility borrowings	297,000	211,000	114,000
Repayment of revolving credit facility borrowings	(91,000)	(310,000)	(15,000)
Debt issuance costs paid	(25,634)	(2,032)	(8,854)
Dividends paid on preferred stock	(6,862)	—	—
Dividends paid on common stock	—	(5,176)	(10,316)
Other, net	(151)	—	1,148
Net cash provided by financing activities	629,263	42,688	148,015
Net increase (decrease) in cash and cash equivalents	5,824	10,138	(113,399)
Cash and cash equivalents - beginning of period	17,650	7,512	120,911
Cash and cash equivalents - end of period	$ 23,474	$ 17,650	$ 7,512
Supplemental disclosures:			
Cash paid for:			
Interest (net of amounts capitalized)	$ 65,107	$ 54,808	$ 44,589
Income taxes (net of refunds received)	$ —	$ (32,603)	$ 210
Non-cash investing and financing activities:			
Other assets acquired related to acquisition	$ 99,213	$ —	$ —
Other liabilities assumed related to acquisition	$ 96,271	$ —	$ —
Common stock transferred as consideration for acquisition	$ 42,300	$ —	$ —

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Shares Outstanding	Preferred Stock	Common Stock	Paid-in Capital	Retained Earnings (Accumulated Deficit)	Deferred Compensation Obligation	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Shareholders' Equity
Balance as of December 31, 2010	45,557	$ —	$ 267	$ 680,981	$ 300,473	$ 2,743	$ (938)	$ (3,250)	$ 980,276
Net loss	—	—	—	—	(132,915)	—	—	—	(132,915)
Dividends declared on common stock ($0.225 per share)	—	—	—	—	(10,316)	—	—	—	(10,316)
Share-based compensation	11	—	1	7,429	—	—	—	—	7,430
Deferred compensation	—	—	—	—	—	877	—	(620)	257
Exercise of stock options	95	—	1	1,225	—	—	—	—	1,226
Restricted stock unit vesting	51	—	1	270	—	—	—	—	271
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	(146)	—	(146)
Other	—	—	—	226	—	—	—	—	226
Balance as of December 31, 2011	45,714	—	270	690,131	157,242	3,620	(1,084)	(3,870)	846,309
Net loss	—	—	—	—	(104,589)	—	—	—	(104,589)
Issuance of preferred stock	—	1,150	—	109,312	—	—	—	—	110,462
Issuance of common stock	9,200	—	92	43,258	—	—	—	—	43,350
Dividends declared on preferred stock ($146.67 per preferred share)	—	—	—	—	(1,687)	—	—	—	(1,687)
Dividends declared on common stock ($0.1125 per share)	—	—	—	—	(5,176)	—	—	—	(5,176)
Share-based compensation	80	—	1	6,346	—	—	—	—	6,347
Deferred compensation	35	—	—	—	—	(509)	—	507	(2)
Restricted stock unit vesting	88	—	1	(1)	—	—	—	—	—
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	102	—	102
Balance as of December 31, 2012	55,117	1,150	364	849,046	45,790	3,111	(982)	(3,363)	895,116
Net loss	—	—	—	—	(143,070)	—	—	—	(143,070)
Issuance of common stock	10,000	—	100	42,041	—	—	—	—	42,141
Dividends declared on preferred stock ($600.00 per preferred share)	—	—	—	—	(6,900)	—	—	—	(6,900)
Share-based compensation	78	—	1	5,780	—	—	—	—	5,781
Deferred compensation	31	—	—	(679)	—	(319)	—	321	(677)
Exercise of stock options	3	—	—	16	—	—	—	—	16
Restricted stock unit vesting	78	—	1	(252)	—	—	—	—	(251)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	1,249	—	1,249
Other	—	—	—	(4,601)	—	—	—	—	(4,601)
Balance as of December 31, 2013	65,307	$ 1,150	$ 466	$ 891,351	$ (104,180)	$ 2,792	$ 267	$ (3,042)	$ 788,804

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation ("Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas in various onshore regions of the United States. Our current operations consist primarily of the drilling of unconventional horizontal development wells in shale formations and are currently concentrated in the Eagle Ford Shale in South Texas. We also have operations in the Granite Wash in the Mid-Continent (primarily Oklahoma), the Haynesville Shale and Cotton Valley in East Texas and the Selma Chalk in Mississippi.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our Consolidated Financial Statements include the accounts of Penn Virginia and all of its subsidiaries. Intercompany balances and transactions have been eliminated.

Use of Estimates

Preparation of our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in our Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Such estimates include certain asset and liability valuations as further described in these Notes. Actual results could differ from those estimates.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Derivative Instruments

From time to time, we utilize derivative instruments to mitigate our financial exposure to commodity price and interest rate volatility. The derivative instruments, which are placed with financial institutions that we believe are of acceptable credit risk, take the form of collars, swaps and swaptions. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. Our derivative instruments are not formally designated as hedges. We recognize changes in fair value in earnings currently as a component of the Derivatives caption on our Consolidated Statements of Operations. We have experienced and could continue to experience significant changes in the amount of derivative gains or losses recognized due to fluctuations in the value of these commodity derivative contracts, which fluctuate with changes in crude oil and natural gas prices and interest rates.

Oil and Gas Properties

We use the successful efforts method to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We will carry the costs of an exploratory well as an asset if the well has found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may take us more than one year to evaluate the future potential of the exploratory well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to the necessary facilities or receiving such permits and approvals and believe that they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis.

Depreciation, depletion and amortization ("DD&A") of proved producing properties is computed using the units-of-production method. Natural gas is converted to a liquids equivalent on the basis that six thousand cubic feet of natural gas is equivalent to one barrel of liquids. Historically, we have adjusted our depletion rate throughout the year as new data becomes available and in the fourth quarter based on our year-end reserve report.

Other Property and Equipment

Other property and equipment consists primarily of gathering systems and related support equipment. Property and equipment are carried at cost and include expenditures for additions and improvements, such as roads and land improvements, which increase the productive lives of existing assets. Maintenance and repair costs are charged to expense as incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized.

We compute depreciation and amortization of property and equipment using the straight-line balance method over the estimated useful life of each asset as follows: Gathering systems - fifteen to twenty years and Other property and equipment - three to twenty years.

Impairment of Long-Lived and Other Assets

We review assets for impairment when events or circumstances indicate a possible decline in the recoverability of the carrying value of such property. If the carrying value of the asset is determined to be impaired, we reduce the asset to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and could include estimates of future production, commodity prices based on published forward commodity price curves as of the date of the estimate, operating and development costs, intent to develop properties and a risk-adjusted discount rate.

We review oil and gas properties for impairment periodically when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. Performing the impairment evaluations requires use of judgments and estimates since the results are dependent on future events. Such events include estimates of proved and unproved reserves, future commodity prices, the timing of future production, capital expenditures and intent to develop properties, among others. We cannot predict whether impairment charges will be required in the future.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. Unproved properties whose acquisition costs are insignificant to total oil and gas properties are amortized in the aggregate over the lesser of five years or the average remaining lease term and the amortization is charged to exploration expense. We assess unproved properties whose acquisition costs are relatively significant, if any, for impairment on a stand-alone basis. As exploration work progresses and the reserves on properties are proven, capitalized costs of these properties are subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work is charged to exploration expense. The timing of any write-downs of any significant unproved properties depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. Associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our AROs relate to the plugging and abandonment of oil and gas wells and the associated asset is recorded as a component of oil and gas properties. After recording these amounts, the ARO is accreted to its future estimated value, and the additional capitalized costs are depreciated over the productive life of the assets. Both the accretion of the ARO and the depreciation of the related long-lived assets are included in the DD&A expense caption on our Consolidated Statements of Operations.

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates. In assessing our deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and our ability to utilize tax credits and operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies. We recognize interest attributable to income taxes, to the extent they arise, as a component of interest expense and penalties as a component of income tax expense.

Due to the geographic scope of our operations, we are subject to ongoing tax examinations in numerous domestic jurisdictions. Accordingly, we may record incremental tax expense based upon the more-likely-than-not outcomes of uncertain tax positions. In addition, when applicable, we adjust the previously recorded tax expense to reflect examination results when the position is effectively settled. Our ongoing assessments of the more-likely-than-not outcomes of the examinations and related tax positions require judgment and can increase or decrease our effective tax rate, as well as impact our operating results. The specific timing of when the resolution of each tax position will be reached is uncertain.

Revenue Recognition

We record revenues associated with sales of crude oil, NGLs and natural gas when title passes to the customer. We recognize natural gas sales revenues from properties in which we have an interest with other producers on the basis of our net revenue interest ("entitlement" method of accounting). Natural gas imbalances occur when we sell more or less than our entitled ownership percentage of natural gas production. We treat any amount received in excess of our share as a liability. If we take less than we are entitled to take, we record the under-delivery as a receivable. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest partners and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production, particularly from properties that are operated by our partners. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

Share-Based Compensation

Our stock compensation plans permit the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. We measure the cost of employee services received in exchange for an award of equity-classified instruments based on the grant-date fair value of the award. Compensation cost associated with the liability-classified awards is measured at the end of each reporting period and recognized based on the period of time that has elapsed during the applicable performance period.

Recent Accounting Standards

Effective January 1, 2013, we adopted Accounting Standards Update No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-02"). The disclosures required by ASU 2013-02 are included in Note 13 to our Consolidated Financial Statements. The adoption of ASU 2013-02 did not have a significant impact on our Consolidated Financial Statements and Notes to the Consolidated Financial Statements.

Subsequent Events

Management has evaluated all activities of the Company, through the date upon which our Consolidated Financial Statements were issued, and concluded that, except for recent developments regarding an arbitration process with respect to our Eagle Ford Shale acquisition in 2013 (the "2013 EF Acquisition") and the completion of the sale of our natural gas gathering assets in South Texas as discussed in Note 3, no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes to Consolidated Financial Statements.

3. Acquisitions and Divestitures

Acquisitions

On April 24, 2013 (the "Acquisition Date"), we acquired producing properties and undeveloped leasehold interests in the Eagle Ford Shale play in connection with the 2013 EF Acquisition. The 2013 EF Acquisition was originally valued at $401 million with an effective date of January 1, 2013 (the "Effective Date"). On the Acquisition Date, we paid approximately $380 million in cash, including approximately $19 million of initial purchase price adjustments related to the period from the Effective Date to the Acquisition Date utilizing a portion of the proceeds from the private placement of $775 million of 8.5% Senior Notes due 2020 (the "2020 Senior Notes"), and issued to the seller 10 million shares of our common stock (the "Shares") with a fair value of $4.23 per Share. Shortly after the Acquisition Date, certain of our joint interest partners exercised preferential rights related to the 2013 EF Acquisition. We received approximately $21 million from the exercise of these rights, which was recorded as a decrease to our purchase price for the 2013 EF Acquisition.

We incurred $2.6 million of transaction costs associated with the 2013 EF Acquisition, including advisory, legal, due diligence and other professional fees. These costs, as well as fees that we paid to the seller for certain transition services, have been included in the General and administrative caption on our Consolidated Statements of Operations.

Since 2013, we have been involved in an arbitration with Magnum Hunter Resources Corporation ("MHR"), the seller in our 2013 EF Acquisition. The arbitration relates to disputes we have with MHR regarding contractual adjustments to the purchase price for the 2013 EF Acquisition and suspense funds that we believe MHR is obligated to transfer to us. On February 3, 2014, both we and MHR submitted initial briefs describing our respective positions to the arbitrator. MHR has acknowledged that it owes us approximately $26.5 million; we believe the amount is higher. Both parties are scheduled to submit rebuttals to the initial briefs on March 3, 2014. We expect this matter to be resolved early during the second quarter of 2014.

We accounted for the 2013 EF Acquisition by applying the acquisition method of accounting as of the Acquisition Date. The initial accounting for the 2013 EF Acquisition as presented below is based upon preliminary information and was not complete, due primarily to the aforementioned arbitration, as of the date our Consolidated Financial Statements were issued.

In the three months ended December 31, 2013, we recorded certain measurement period adjustments based on the receipt of additional information which had the effect of decreasing the fair value of our oil and gas properties by $14 million offset by increases to accounts receivable of $46 million and accounts payable and accrued expenses of $32 million. Accordingly, we have updated the preliminary fair values of net assets acquired from those that were disclosed in our Quarterly Report on Form 10-Q for the period ended September 30, 2013. The following table represents the fair values assigned to the net assets acquired as of the Acquisition Date and the consideration transferred:

Assets		
Oil and gas properties - proved	$	277,888
Oil and gas properties - unproved		119,709
Accounts receivable, net		97,145
Other current assets		2,068
		496,810
Liabilities		
Accounts payable and accrued expenses		94,771
Other liabilities		1,500
		96,271
Net assets acquired	$	400,539
Cash, net of amounts received for preferential rights	$	358,239
Fair value of the Shares issued to seller		42,300
Consideration transferred	$	400,539

The fair values of the acquired net assets were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future cash flows and (v) a market-based weighted-average cost of capital. Because many of these inputs are not observable, we have classified the initial fair value estimates as Level 3 inputs as that term is defined in U.S. GAAP.

The results of operations attributable to the 2013 EF Acquisition have been included in our Consolidated Financial Statements from the Acquisition Date. The following table presents unaudited summary pro forma financial information for the periods presented assuming the 2013 EF Acquisition and the related financing occurred as of January 1, 2012. The pro forma financial information does not purport to represent what our results of operations would have been if the 2013 EF Acquisition had occurred as of this date or the results of operations for any future periods.

	Year Ended December 31,			
	2013		2012	
Total revenues	$	457,811	$	389,260
Net loss attributable to common shareholders	$	(148,272)	$	(106,059)
Loss per share - basic and diluted	$	(2.27)	$	(1.83)

Divestitures

In December 2013, we entered into an agreement to sell our natural gas gathering assets in South Texas. The transaction closed in January 2014 and resulted in the receipt of proceeds of approximately $94 million, net to our working interest.

In July 2012, we sold substantially all of our natural gas assets in West Virginia, Kentucky and Virginia, which comprised a significant portion of our operations in Appalachia, for approximately $100 million, excluding transaction costs and before customary purchase and sale adjustments. We received proceeds of $95.7 million, net of transaction costs and customary closing adjustments, and recognized a gain of $3.3 million in connection with the transaction. An impairment charge of $28.6 million was recognized in the second quarter of 2012 with respect to these assets.

In December 2011, we sold approximately 2,700 net undeveloped acres in Butler and Armstrong Counties in Pennsylvania for proceeds of $8.1 million, net of transaction costs. We recognized a gain of $3.3 million in connection with this transaction. In August 2011, we sold a substantial portion of our Arkoma Basin assets, including primarily natural gas and coal bed methane properties in Oklahoma and Texas, for approximately $30 million, excluding transaction costs and customary purchase and sale adjustments. Upon the final settlement, we recognized an insignificant loss in connection with the transaction, following an impairment of approximately $71 million in the second quarter of 2011.

During 2013, the payment of post-closing adjustments attributable to sales of properties from prior years were partially offset by net proceeds from the sale of individually insignificant oil and gas properties and tubular inventory and well materials resulting in net payments of $0.1 million and a recognized loss on the sale of assets of $0.3 million. During 2012 and 2011, we also received net proceeds of $1.0 million and $1.2 million and recognized a net gain of $1.0 million and a net loss of $0.7 million, respectively, from the sale of various non-core oil and gas properties and tubular inventory and well materials.

4. Accounts Receivable and Major Customers

The following table summarizes our accounts receivable by type as of the dates presented:

	As of December 31,	
	2013	2012
Customers	$ 93,288	$ 43,967
Joint interest partners	76,199	16,154
Other [1]	25,538	4,523
	195,025	64,644
Less: Allowance for doubtful accounts	(622)	(1,666)
	$ 194,403	$ 62,978

[1] Amounts as of December 31, 2013 are comprised substantially of amounts due from the seller and other parties for purchase price adjustments attributable to the 2013 EF Acquisition.

For the year ended December 31, 2013, three customers accounted for $181.7 million, or approximately 42% of our consolidated product revenues. The revenues generated from these customers during 2013 were $70.4 million, $55.9 million and $55.4 million or 16%, 13% and 13% of the consolidated total, respectively. As of December 31, 2013, $34.8 million, or approximately 37% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2012, four customers accounted for $182.0 million, or approximately 59% of our consolidated product revenues. The revenues generated from these customers during 2012 were $60.1 million, $46.7 million, $41.5 million and $33.8 million, or approximately 19%, 15%, 13% and 11% of the consolidated total, respectively. As of December 31, 2012, $21.6 million, or approximately 49% of our consolidated accounts receivable from customers was related to these customers. No significant uncertainties exist related to the collectability of amounts owed to us by any of these customers.

5. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to crude oil and natural gas price volatility as well as the volatility in interest rates attributable to our debt instruments. Our derivative instruments are not formally designated as hedges. The disclosures included herein incorporate the requirements of Accounting Standards Update No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* as amended by Accounting Standards Update No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*.

Commodity Derivatives

We utilize collars, swaps and swaptions, which are placed with financial institutions that we believe are acceptable credit risks, to hedge against the variability in cash flows associated with anticipated sales of our future oil and gas production. While the use of derivative instruments limits the risk of adverse price movements, such use may also limit future revenues from favorable price movements.

The counterparty to a collar or swap contract is required to make a payment to us if the settlement price for any settlement period is below the floor or swap price for such contract. We are required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling or swap price for such contract. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A 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 the term of the swaption is higher than or equal to the swaption strike price on the exercise date, the counterparty will exercise its option to enter into a fixed-price swap at the swaption strike price for the term of the swaption, at which point the contract functions as a fixed-price swap. If the forward commodity price for the term of the swaption is lower than the swaption strike price on the exercise date, the option expires and no fixed-price swap is in effect.

We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for NYMEX Henry Hub gas and West Texas Intermediate crude oil closing prices as of the end of the reporting period. The discounted cash flows utilize discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position.

The following table sets forth our commodity derivative positions as of December 31, 2013:

	Instrument	Average Volume Per Day	Weighted Average Price		Fair Value	
			Floor/Swap	Ceiling	Asset	Liability
Crude Oil:		**(barrels)**	**($/barrel)**			
First quarter 2014	Collars	1,500	$ 93.33	$ 102.80	$ —	$ 28
Second quarter 2014	Collars	1,500	$ 93.33	102.80	128	—
First quarter 2014	Swaps	8,500	$ 94.00		—	3,352
Second quarter 2014	Swaps	8,500	$ 94.00		—	2,280
Third quarter 2014	Swaps	9,000	$ 93.38		—	1,025
Fourth quarter 2014	Swaps	9,000	$ 93.38		607	—
First quarter 2015	Swaps	3,000	$ 91.92		88	—
Second quarter 2015	Swaps	3,000	$ 91.92		435	—
Third quarter 2015	Swaps	2,000	$ 91.48		410	—
Fourth quarter 2015	Swaps	2,000	$ 91.48		556	—
Natural Gas:		**(in MMBtu)**	**($/MMBtu)**			
First quarter 2014	Collars	5,000	$ 4.00	$ 4.50	—	3
First quarter 2014	Swaps	10,000	$ 4.28		1	—
Second quarter 2014	Swaps	15,000	$ 4.10		—	1
Third quarter 2014	Swaps	15,000	$ 4.10		—	60
Fourth quarter 2014	Swaps	5,000	$ 4.50		125	—
First quarter 2015	Swaps	5,000	$ 4.50		64	—
Settlements to be paid in subsequent period					—	423

Interest Rate Swaps

In February 2012, we entered into an interest rate swap agreement to establish variable interest rates on approximately one-third of the outstanding obligation under our 7.25% Senior Notes due 2019 (the "2019 Senior Notes"). In May 2012, we terminated this agreement and received $1.2 million in cash proceeds.

In December 2009, we entered into an interest rate swap agreement to establish variable rates on approximately one-third of the face amount of the outstanding obligation under our 10.375% Senior Notes due 2016 (the "2016 Senior Notes"). In August 2011, we terminated this agreement and received $2.9 million in cash proceeds.

As of December 31, 2013, we had no interest rate derivative instruments outstanding.

Financial Statement Impact of Derivatives

The impact of our derivatives activities on income is included in the Derivatives caption on our Consolidated Statements of Operations. The following table summarizes the effects of our derivative activities for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Impact by contract type:			
Commodity contracts	$ (20,852)	$ 34,781	$ 14,422
Interest rate contracts	—	1,406	1,229
	$ (20,852)	$ 36,187	$ 15,651
Cash settlements and gains (losses):			
Cash received (paid) for:			
Commodity contract settlements	$ (1,042)	$ 28,317	$ 23,562
Interest rate contract settlements	—	1,406	3,818
	(1,042)	29,723	27,380
Gains (losses) attributable to:			
Commodity contracts	(19,810)	6,464	(9,140)
Interest rate contracts	—	—	(2,589)
	(19,810)	6,464	(11,729)
	$ (20,852)	$ 36,187	$ 15,651

The effects of derivative gains and (losses) and cash settlements of our commodity and interest rate derivatives are reported as adjustments to reconcile net income (loss) to net cash provided by operating activities. These items are recorded in the Derivative contracts section of our Consolidated Statements of Cash Flows under the Net gains and Cash settlements captions.

The following table summarizes the fair value of our derivative instruments, as well as the locations of these instruments, on our Consolidated Balance Sheets as of the dates presented:

		Fair Values as of			
		December 31, 2013		December 31, 2012	
Type	**Balance Sheet Location**	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Commodity contracts	Derivative assets/liabilities - current	$ 3,830	$ 10,141	$ 11,292	$ —
Interest rate contracts	Derivative assets/liabilities - current	—	—	—	—
		3,830	10,141	11,292	—
Commodity contracts	Derivative assets/liabilities - noncurrent	1,552	—	5,181	1,421
Interest rate contracts	Derivative assets/liabilities - noncurrent	—	—	—	—
		1,552	—	5,181	1,421
		$ 5,382	$ 10,141	$ 16,473	$ 1,421

As of December 31, 2013, we reported a commodity derivative asset of $5.4 million. The contracts associated with this position are with five counterparties, all of which are investment grade financial institutions, and are substantially concentrated with three of those counterparties. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from our counterparties any cash collateral in connection with our derivative positions. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

6. Property and Equipment

The following table summarizes our property and equipment as of the dates presented:

	As of December 31, 2013	As of December 31, 2012
Oil and gas properties:		
Proved	$ 2,970,047	$ 2,277,811
Unproved	101,520	60,746
Total oil and gas properties	3,071,567	2,338,557
Other property and equipment	105,421	93,648
Total property and equipment	3,176,988	2,432,205
Accumulated depreciation, depletion and amortization	(939,684)	(708,846)
	$ 2,237,304	$ 1,723,359

The following table describes the changes in capitalized exploratory drilling costs that are pending the determination of proved reserves for the periods presented:

	2013		2012		2011	
	Number of Wells	Cost	Number of Wells	Cost	Number of Wells	Cost
Balance at beginning of year	1	$ 4,435	—	$ —	1	$ 6,180
Additions pending determination of proved reserves	—	—	1	4,435	—	—
Reclassification to wells, equipment and facilities based on the determination of proved reserves	(1)	(4,435)	—	—	—	—
Charged to exploration expense	—	—	—	—	(1)	(6,180)
Balance at end of year	—	$ —	1	$ 4,435	—	$ —

7. Asset Retirement Obligations

The following table reconciles our AROs as of the dates presented, which are included in the Other liabilities caption on our Consolidated Balance Sheets:

	As of December 31, 2013	As of December 31, 2012
Balance at beginning of year	$ 4,513	$ 6,283
Liabilities incurred[1]	1,675	57
Liabilities settled	(220)	(236)
Sale of properties	—	(1,976)
Accretion expense	469	385
Balance at end of year	$ 6,437	$ 4,513

[1] Includes $1.5 million recognized in connection with the 2013 EF Acquisition.

8. Long-Term Debt

The following table summarizes our long-term debt as of the dates presented:

	As of December 31, 2013	As of December 31, 2012
Revolving credit facility	$ 206,000	$ —
Senior notes due 2016, net of discount (principal amount of $300,000)	—	294,759
Senior notes due 2019	300,000	300,000
Senior notes due 2020	775,000	—
	$ 1,281,000	$ 594,759

Revolving Credit Facility

The revolving credit facility (the "Revolver") provides for a $400 million revolving commitment and has a borrowing base of $425 million. The Revolver has an accordion feature that allows us to increase the commitment by up to an additional $200 million upon receiving additional commitments from one or more lenders. The Revolver also includes a $20 million sublimit for the issuance of letters of credit. The Revolver is governed by a borrowing base calculation, which is redetermined semi-annually, and the availability under the Revolver may not exceed the lesser of the aggregate commitments and the borrowing base. The next semi-annual redetermination is scheduled for May 2014. The Revolver allows for the administrative agent to replace any lender who fails to approve a borrowing base increase approved by lenders representing two thirds of the aggregate commitment. The Revolver is available to us for general purposes including working capital, capital expenditures and acquisitions. The Revolver matures in September 2017. We had letters of credit of $2.7 million outstanding as of December 31, 2013. As of December 31, 2013, our available borrowing capacity under the Revolver was $191.3 million.

Borrowings under the Revolver bear interest, at our option, at either (i) a rate derived from the London Interbank Offered Rate, as adjusted for statutory reserve requirements for Eurocurrency liabilities ("Adjusted LIBOR"), plus an applicable margin (ranging from 1.500% to 2.500%) or (ii) the greater of (a) the prime rate, (b) the federal funds effective rate plus 0.5% or (c) the one-month Adjusted LIBOR plus 1.0%, and, in each case, plus an applicable margin (ranging from 0.500% to 1.500%). The applicable margin is determined based on the ratio of our outstanding borrowings to the available Revolver capacity. As of December 31, 2013, the actual interest rate on the outstanding borrowings under the Revolver was 2.1875% which is derived from an Adjusted LIBOR rate of 0.1875% plus an applicable margin of 2.00%. Commitment fees are charged at 0.375% to 0.500% on the undrawn portion of the Revolver depending on our ratio of outstanding borrowings to the available Revolver capacity. As of December 31, 2013, commitment fees were charged at a rate of 0.500%.

The Revolver is guaranteed by Penn Virginia and all of our material subsidiaries (the "Guarantor Subsidiaries"). The obligations under the Revolver are secured by a first priority lien on substantially all of our proved oil and gas reserves and a pledge of the equity interests in the Guarantor Subsidiaries.

The Revolver includes both current ratio and leverage ratio financial covenants. The current ratio is defined in the Revolver to include, among other things, adjustments for undrawn availability and may not be less than 1.0 to 1.0. The ratio of total net debt to EBITDAX, a non-GAAP financial measure defined in the Revolver, may not exceed 4.5 to 1.0 through June 30, 2014, 4.25 to 1.0 through December 31, 2014 and then 4.0 to 1.0 through maturity.

2016 Senior Notes

In May 2013, we completed a tender offer and redemption (the "Tender Offer and the Redemption") for all of our outstanding 2016 Senior Notes. We paid a total of $330.9 million including consent payments and accrued interest in connection with the Tender Offer and the Redemption and recognized a loss on the extinguishment of debt of $29.2 million. The loss on extinguishment of debt included non-cash charges of $10.0 million attributable to the write-off of unamortized debt issuance costs and the remaining debt discount associated with the 2016 Senior Notes.

2019 Senior Notes

The 2019 Senior Notes, which were issued at par in April 2011, bear interest at an annual rate of 7.25% payable on April 15 and October 15 of each year. Beginning in April 2015, we may redeem all or part of the 2019 Senior Notes at a redemption price starting at 103.625% of the principal amount and reducing to 100% in June 2017 and thereafter. The 2019 Senior Notes are senior to our existing and future subordinated indebtedness and are effectively subordinated to all of our secured indebtedness, including the Revolver, to the extent of the collateral securing that indebtedness. The obligations under the 2019 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries.

2020 Senior Notes

On April 24, 2013, we completed a private placement of the 2020 Senior Notes. In July 2013, we completed an exchange offer that resulted in the registration of all of the 2020 Senior Notes. The 2020 Senior Notes were priced at par and interest is payable on June 15 and December 15 of each year. The 2020 Senior Notes are fully and unconditionally guaranteed by the Guarantor Subsidiaries. Approximately $380 million of the net proceeds from the private placement, together with the Shares, were used to finance the 2013 EF Acquisition, including purchase price adjustments. The remaining net proceeds were used to pay down borrowings under the Revolver and to fund a portion of the Tender Offer and the Redemption.

The guarantees provided by Penn Virginia, which is the parent company, and the Guarantor Subsidiaries under the Revolver and the senior indebtedness described above are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company and its non-guarantor subsidiaries have no material independent assets or operations. There are no significant restrictions on the ability of the parent company or any of the Guarantor Subsidiaries to obtain funds through dividends or other means, including advances and intercompany notes, among others.

Debt Maturities

We have no debt maturities until September 2017 when the Revolver matures. The 2019 Senior Notes are due in April 2019 and the 2020 Senior Notes are due in May 2020.

9. Income Taxes

The following table summarizes our provision for income taxes for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Current income taxes (benefit)			
Federal	$ —	$ —	$ 1,279
State	—	(26)	(3,933)
	—	(26)	(2,654)
Deferred income tax benefit			
Federal	(77,046)	(60,676)	(80,529)
State	(650)	(8,000)	(4,972)
	(77,696)	(68,676)	(85,501)
	$ (77,696)	$ (68,702)	$ (88,155)

The following table reconciles the difference between the income taxes computed by applying the statutory tax rate to income from continuing operations before income taxes and our reported income tax expense for the periods presented:

	Year Ended December 31,					
	2013		2012		2011	
Computed at federal statutory rate	$ (77,268)	(35.0)%	$ (60,652)	(35.0)%	$ (77,374)	(35.0)%
State income taxes, net of federal income tax benefit	(650)	(0.3)%	(8,026)	(4.6)%	(4,825)	(2.2)%
Other, net	222	0.1 %	(24)	— %	(5,956)	(2.7)%
	$ (77,696)	(35.2)%	$ (68,702)	(39.6)%	$ (88,155)	(39.9)%

The following table summarizes the principal components of our net deferred income tax liability as of the dates presented:

	As of December 31,	
	2013	2012
Deferred tax liabilities:		
Property and equipment	$ 248,164	$ 311,002
Fair value of derivative instruments	—	5,268
Total deferred tax liabilities	248,164	316,270
Deferred tax assets:		
Fair value of derivative instruments	1,665	—
Pension and postretirement benefits	2,248	2,864
Share-based compensation	6,907	10,760
Net operating loss (“NOL”) carryforwards	115,355	102,407
Other	18,029	15,788
	144,204	131,819
Less: Valuation allowance	(35,727)	(26,686)
Total deferred tax assets	108,477	105,133
Net deferred tax liability	$ 139,687	$ 211,137

As of December 31, 2013, we had federal NOL carryforwards of approximately $225.3 million, which expire starting in 2031, and state NOL carryforwards of approximately $56.2 million, which expire between 2024 and 2033. As of December 31, 2013 and 2012, valuation allowances of $55.0 million and $41.0 million, respectively, had been recorded for deferred tax assets associated with state NOL carryforwards that were not more-likely-than-not to be realized.

As of December 31, 2011, we classified $31.2 million of deferred tax assets as a current income tax receivable attributable to the federal NOL expected to be utilized. In 2012, we received a federal tax refund of approximately $32 million from the carryback of the 2011 federal NOL, and the remainder of the NOL is available for carryforward.

We have no liability for unrecognized tax benefits as of December 31, 2013 and 2012. There were no interest and penalty charges recognized during the years ended December 31, 2013, 2012 and 2011. Tax years from 2010 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

10. Additional Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	As of December 31,	
	2013	2012
Other current assets:		
Tubular inventory and well materials	$ 2,271	$ 4,033
Prepaid expenses	3,653	562
	$ 5,924	$ 4,595
Other assets:		
Debt issuance costs	$ 30,239	$ 13,186
Assets of supplemental employee retirement plan [1]	3,734	3,237
Other	562	1,511
	$ 34,535	$ 17,934
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 120,278	$ 37,835
Drilling and other lease operating costs	51,529	37,703
Royalties	39,929	14,390
Production and franchise taxes	5,338	2,874
Compensation - related [2, 3]	8,584	6,853
Interest	15,718	5,828
Preferred stock dividends	1,725	1,687
Other	4,903	4,485
	$ 248,004	$ 111,655
Other liabilities:		
Firm transportation obligation	$ 13,245	$ 14,333
Asset retirement obligations	6,437	4,513
Defined benefit pension obligations [2]	1,579	1,821
Postretirement health care benefit obligations [2]	1,023	2,634
Deferred compensation - supplemental employee retirement plan obligation and other [1]	3,883	3,310
Other	7,219	2,290
	$ 33,386	$ 28,901

[1] Includes the assets and liabilities of the Penn Virginia Corporation Supplemental Employee Retirement Plan (“SERP”) which is a nonqualified supplemental employee retirement savings plan. Assets of the SERP are held in a Rabbi Trust. Shares of our common stock held by the Rabbi Trust are presented for financial reporting purposes as treasury stock carried at cost.

[2] Includes the combined unfunded benefit obligations under our defined benefit pension and postretirement health care plans of $3.0 million and $5.1 million as of December 31, 2013 and 2012. The expense recognized with respect to these plans was $0.3 million, $0.3 million and $0.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

[3] Includes employer matching obligations under our defined contribution retirement plan of $0.2 million and $0.2 million as of December 31, 2013 and 2012, respectively. The expense recognized with respect to this plan was $1.0 million, $0.9 million and $1.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

11. Fair Value Measurements

We apply the authoritative accounting provisions for measuring fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

We use a hierarchy that prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below.

Fair value measurements are classified and disclosed in one of the following three categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Level 1 inputs generally provide the most reliable evidence of fair value.
- Level 2: Quoted prices in markets that are not active or inputs, which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3: Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity).

Our financial instruments that are subject to fair value disclosure consist of cash and cash equivalents, accounts receivable, accounts payable, derivatives and long-term debt. As of December 31, 2013, the carrying values of all of these financial instruments, except the portion of long-term debt with fixed interest rates, approximated fair value.

The following table summarizes the fair value of our long-term debt with fixed interest rates, which is estimated based on the published market prices for these debt obligations as of the dates presented:

	December 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Notes due 2016	$ —	$ —	$ 316,500	$ 294,759
Senior Notes due 2019	307,500	300,000	286,500	300,000
Senior Notes due 2020	837,969	775,000	—	—
	$ 1,145,469	$ 1,075,000	$ 603,000	$ 594,759

Recurring Fair Value Measurements

Certain financial assets and liabilities are measured at fair value on a recurring basis in our Consolidated Balance Sheets. The following tables summarize the valuation of those assets and liabilities as of the dates presented:

	As of December 31, 2013			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets - current	$ 3,830	$ —	$ 3,830	$ —
Commodity derivative assets - noncurrent	1,552	—	1,552	—
Assets of SERP	3,734	3,734	—	—
Liabilities:				
Commodity derivative liabilities - current	—	—	—	—
Commodity derivative liabilities - noncurrent	(10,141)	—	(10,141)	—
Deferred compensation - SERP obligation and other	(3,879)	(3,879)	—	—

	As of December 31, 2012			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets - current	$ 11,292	$ —	$ 11,292	$ —
Commodity derivative assets - noncurrent	5,181	—	5,181	—
Assets of SERP	3,237	3,237	—	—
Liabilities:				
Commodity derivative liabilities - current	—	—	—	—
Commodity derivative liabilities - noncurrent	(1,421)	—	(1,421)	—
Deferred compensation - SERP obligation and other	(3,305)	(3,305)	—	—

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one level of the fair value hierarchy to another level. In such instances, the transfer is deemed to have occurred at the beginning of the quarterly period in which the event or change in circumstances that caused the transfer occurred. There were no transfers during the years ended December 31, 2013, 2012 and 2011.

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments based on discounted cash flows derived from third-party quoted forward prices for West Texas Intermediate crude oil and NYMEX Henry Hub gas closing prices as of the end of the reporting periods. We generally use the income approach, using valuation techniques that convert future cash flows to a single discounted value. Each of these is a level 2 input.
- *Assets of SERP*: We hold various publicly traded equity securities in a Rabbi Trust as assets for funding certain deferred compensation obligations. The fair values are based on quoted market prices, which are level 1 inputs.
- *Deferred compensation - SERP obligations*: Certain of our deferred compensation obligations are ultimately to be settled in cash based on the underlying fair value of certain assets, including those held in the Rabbi Trust. The fair values are based on quoted market prices, which are level 1 inputs.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements utilized in the preparation of our Consolidated Financial Statements are those attributable to the recognition and measurement of net assets acquired, the recognition and measurement of asset impairments and the initial determination of AROs. The factors used to determine fair value for purposes of recognizing and measuring net assets acquired and asset impairments include, but are not limited to, estimates of proved and probable reserves, future commodity prices, indicative sales prices for properties, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we have categorized the amounts as level 3 inputs.

The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as level 3 inputs.

12. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2013, by category, for the next five years and thereafter:

Year	Minimum Rentals	Drilling and Completion	Firm Transportation	Other Commitments
2014	$ 1,884	$ 88,398	$ 2,002	$ 4,021
2015	1,808	4,615	2,002	4,429
2016	1,702	—	1,095	5,138
2017	652	—	1,095	—
2018	666	—	1,095	—
Thereafter	681	—	10,767	—
Total	$ 7,393	$ 93,013	$ 18,056	$ 13,588

Rental Commitments

Operating lease rental expense in the years ended December 31, 2013, 2012 and 2011 was $9.4 million, $11.0 million and $11.4 million, respectively, related primarily to field equipment, office equipment and office leases.

Drilling and Completion Commitments

We have agreements to purchase oil and gas well drilling and well completion services from third parties with original terms of up to two years. As of December 31, 2013, there were no well drilling or well completion agreements with terms that extended beyond December 31, 2014. The well drilling agreements include early termination provisions that would require us to pay penalties if we terminate the agreements prior to the end of their original terms. The amount of penalty is based on the number of days remaining in the contractual term. As of December 31, 2013, the penalty amount would have been $19.0 million if we had terminated our agreements on that date.

Firm Transportation Commitments

We have entered into contracts that provide firm transportation capacity rights for specified volumes per day on various pipeline systems with terms that range from 1 to 15 years. The contracts require us to pay transportation demand charges regardless of the amount of pipeline capacity we use. We may sell excess capacity to third parties at our discretion.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have purchase commitments for certain bulk equipment and materials utilized in the construction of our production facilities, minimum commitments under a natural gas gathering and compression service agreement for a portion of our natural gas and NGL production, information technology licensing and service agreements and certain consulting agreements, among others.

Legal

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. During 2010, we established a $0.9 million reserve for a litigation matter pertaining to certain properties that remains outstanding as of December 31, 2013. In addition to the reserve for litigation, we maintain a suspense account which includes approximately $1.9 million representing the excess of revenues received over costs incurred attributable to these properties. As discussed in Note 3, we are involved in an arbitration with the seller in connection with our 2013 EF Acquisition.

Environmental Compliance

Extensive federal, state and local laws govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination, rendering a person liable for environmental and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of December 31, 2013, we have recorded AROs of $6.4 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general. We believe that we are in substantial compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition or results of operations. Nevertheless, changes in existing environmental laws or the adoption of new environmental laws, including any significant limitation on the use of hydraulic fracturing, have the potential to adversely affect our operations.

13. Shareholders' Equity

Preferred Stock

In October 2012, we completed a registered offering of 11,500 shares of our 6% Series A Convertible Perpetual Preferred Stock (the "6% Preferred Stock") that provided $110.3 million of proceeds, net of underwriting fees and issuance costs.

The annual dividend on each share of the 6% Preferred Stock is 6.00% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on January 15, April 15, July 15 and October 15 of each year, commencing on January 15, 2013. We may, at our option, pay dividends in cash, common stock or a combination thereof. Our board of directors declared quarterly cash dividends of $150 per share for each of the quarterly periods in the year ended December 31, 2013. In December 2012, the board of directors declared a quarterly cash dividend of $146.67 per share for the period from the original issue date of October 17, 2012 through January 14, 2013.

Each share of the 6% Preferred Stock is convertible, at the option of the holder, into a number of shares of our common stock equal to the liquidation preference of $10,000 divided by the conversion price, which is initially $6.00 per share and is subject to specified anti-dilution adjustments. The initial conversion rate is equal to 1,666.67 shares of our common stock for each share of the 6% Preferred Stock. The initial conversion price represents a premium of 20 percent relative to the 2012 common stock offering price of $5.00 per share. The 6% Preferred Stock is not redeemable by us or the holders at any time. At any time on or after October 15, 2017, we may, at our option, cause all outstanding shares of the 6% Preferred Stock to be automatically converted into shares of our common stock at the then-applicable conversion price if the closing sale price of our common stock exceeds 130% of the then-applicable conversion price for a specified period prior to conversion. If a holder elects to convert shares of the 6% Preferred Stock upon the occurrence of certain specified fundamental changes, we may be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option value.

Common Stock

As discussed in Note 3, we issued the Shares to the seller in April 2013 as part of the consideration paid in connection with the 2013 EF Acquisition. In connection with the Shares issued to the seller, we entered into a Registration Rights, Lock-Up and Buy-Back Agreement and a Standstill Agreement (collectively, the "Share Agreements") which provided for certain rights and obligations. In September 2013, the seller sold the Shares to institutional investors in a series of private transactions. Accordingly, the Share Agreements no longer have effect.

Concurrent with the 6% Preferred Stock offering in October 2012, we completed a registered offering of 9.2 million shares of our common stock that provided $43.5 million of proceeds, net of underwriting fees and issuance costs. The proceeds from the combined offerings were used to repay outstanding borrowings under the Revolver and for general corporate purposes.

In July 2012, we discontinued the quarterly dividend on our common stock.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income and losses are entirely attributable to our pension and postretirement benefit obligations. The accumulated income (losses), net of tax, were $0.3 million, $(1.0) million and $(1.1) million as of December 31, 2013, 2012 and 2011, respectively.

Treasury Stock

Prior to 2012, certain of our employees made elective deferrals of compensation under the SERP, a portion of which was invested, at the employee's direction, in our common stock. In addition, a portion of the compensation paid to certain non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon retirement from our board of directors.

Shares of our common stock held by the SERP and deferred common stock units that have not been converted into common stock are presented for financial reporting purposes as treasury stock carried at cost. A total of 233,063 and 218,320 shares have been recorded as treasury stock as of December 31, 2013 and 2012, respectively.

14. Share-Based Compensation

The Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (the "LTI Plan") permits the grant of incentive and nonqualified stock options, common stock, deferred common stock units, restricted stock and restricted stock units to our employees and directors. As of December 31, 2013, there were 3,364,758 shares available for issuance to employees and directors pursuant to the LTI Plan.

With the exception of performance-based restricted stock units ("PBRSUs"), all of the awards issued under our LTI Plan are classified as equity instruments because they result in the issuance of common stock on the date of grant, upon exercise or are otherwise payable in common stock upon vesting, as applicable. The compensation cost attributable to these awards is measured at the grant date and recognized over the applicable vesting period as a non-cash item of expense. Because the PBRSUs are payable in cash, they are considered liability-classified awards and are included in the Other liabilities caption on our Consolidated Balance Sheets. Compensation cost associated with the PBRSUs is measured at the end of each reporting period and recognized based on the period of time that has elapsed during each of the individual performance periods.

The following table summarizes share-based compensation expense recognized for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Equity-classified awards:			
Stock option awards	$ 3,123	$ 4,424	$ 5,477
Common, deferred, restricted and restricted unit awards	2,658	1,923	1,953
	5,781	$ 6,347	$ 7,430
Liability-classified awards	4,116	714	—
	$ 9,897	$ 7,061	$ 7,430

Stock Options

The exercise price of all stock options granted under the LTI Plan is equal to the fair market value of our common stock on the date of the grant. Options may be exercised at any time after vesting and prior to ten years following the date of grant. Options vest upon terms established by the compensation and benefits committee of our board of directors (the "Committee"). Generally, options vest over a three-year period, with one-third vesting in each year. In addition, all options will vest upon a change of control of us, as defined in the LTI Plan. In the case of employees, if a grantee's employment terminates (i) for cause, all of the grantee's options, whether vested or unvested, will be forfeited, (ii) by reason of death or disability, the grantee's options will vest and remain exercisable for one year and (iii) for any other reason, the grantee's unvested options will be forfeited and the grantee's vested options will remain exercisable for 90 days. If a grantee is or becomes retirement eligible (age 62 and providing 10 consecutive years of service), all of the grantee's options will vest. We have historically issued new shares to satisfy stock option exercises.

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing formula that uses the assumptions noted in the following table. Expected volatilities are based on historical changes in the market value of our stock. Separate groups of employees that have similar historical exercise behavior are considered separately to estimate expected lives. Options granted have a maximum term of ten years. We base the risk-free interest rate on the U.S. Treasury rate for the week of the grant having a term equal to the expected life of the option.

	2013	2012	2011
Expected volatility	56.9% to 70.1%	67.3% to 72.9%	61.7% to 71.9%
Dividend yield	0.00% to 0.00%	2.25% to 4.98%	1.25% to 2.25%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.34% to 0.58%	0.36% to 0.51%	0.39% to 2.18%

The following table summarizes activity for our most recent fiscal year with respect to stock options:

	Shares Under Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at beginning of year	2,286,734	$ 21.14		
Granted	934,067	4.32		
Exercised	(2,820)	5.67		
Forfeited	(88,912)	20.50		
Outstanding at end of year	3,129,069	$ 16.15	6.7	$ 1,413
Exercisable at end of year	2,167,686	$ 20.39	5.8	$ 443

The weighted-average grant-date fair value of options granted during the years ended December 31, 2013, 2012 and 2011 was $2.35, $2.54 and $7.30 per option. The total intrinsic value of options exercised during the years ended December 31, 2013 and 2011 was less than $0.1 million and $0.4 million. There were no options exercised during 2012.

As of December 31, 2013, we had $1.7 million of unrecognized compensation cost related to unvested stock options. We expect that cost to be recognized over a weighted-average period of 0.8 years. The total grant-date fair values of stock options that vested in 2013, 2012 and 2011 were $2.7 million, $4.7 million and $3.7 million, respectively.

Common Stock

A portion of the compensation paid to certain non-employee members of our board of directors is paid in common stock. Each share of common stock granted as compensation vests immediately upon issuance. In 2013 and 2012, we granted 77,598 and 79,700 shares of common stock to our non-employee directors at a weighted-average grant date fair value of $5.39 and $5.33 per share.

Deferred Common Stock Units

A portion of the compensation paid to certain non-employee members of our board of directors is paid in deferred common stock units. Each deferred common stock unit represents one share of common stock, vests immediately upon issuance, and is available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors receive all cash or other dividends we pay on shares of our common stock.

The following table summarizes activity for our most recent fiscal year with respect to awarded deferred common stock units:

	Deferred Common Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year	202,876	$ 15.33
Granted	46,134	5.58
Converted	(31,302)	18.43
Balance at end of year	217,708	$ 13.01

As of December 31, 2013, 2012 and 2011, shareholders' equity included deferred compensation obligations of $2.8 million, $3.1 million and $3.6 million, respectively, and corresponding amounts for treasury stock.

Restricted Stock

Restricted stock vests upon terms established by the Committee and as specified in the award agreement. In addition, all restricted stock will vest upon a change of control of us. If a grantee's employment terminates for any reason other than death or disability, the grantee's restricted stock will be forfeited unless otherwise determined by the Committee and specified in the award agreement. If a grantee's employment terminates by reason of death or disability, or if a grantee becomes retirement eligible, the grantee's restricted stock will vest. Except as disallowed by the Committee, a grantee shall be entitled to receive any dividends declared on our common stock. Restricted stock vests generally over a three-year period, with one-third vesting in each year. We recognize compensation expense on a straight-line basis over the vesting period.

The total grant-date fair value of restricted stock that vested in 2011 was $0.5 million. There were no unvested restricted stock awards outstanding during 2013 and 2012, and no restricted stock awards vested during 2013 and 2012.

Restricted Stock Units

A restricted stock unit entitles the grantee to receive a share of common stock upon the vesting of the restricted stock unit or, at the discretion of the Committee, the cash equivalent of the fair market value of a share of common stock. The Committee determines the time period over which restricted stock units will vest. In addition, all restricted stock units will vest upon a change of control of us. Unless and to the extent the Committee determines otherwise, (i) If an employee's employment with us or our affiliates terminates for any reason other than death, disability or retirement after becoming retirement eligible, the grantee's restricted stock units will be forfeited and (ii) if a grantee dies, becomes disabled or becomes retirement eligible, the grantee's restricted stock units will vest. If restricted stock units vest early on account of retirement eligibility, payment on the restricted stock units will be made when the restricted stock units would have originally vested, even if that is after retirement. Restricted stock units generally vest over a three-year period, with one-third vesting in each year. Prior to 2013, the Committee, in its discretion, could grant tandem dividend equivalent rights with respect to restricted stock units. Beginning in 2013, the Committee may not grant dividend equivalent rights. A dividend equivalent right is a right to receive an amount in cash equal to, and 30 days after, the cash dividends made with respect to a share of common stock during the period such restricted stock unit is outstanding. Payments of dividend equivalent rights associated with restricted stock units that are expected to vest are recorded as dividends; payments associated with restricted stock units that are not expected to vest are recorded as compensation expense.

The following table summarizes activity for our most recent fiscal year with respect to awarded restricted stock units:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Balance at beginning of year [1]	91,971	$ 10.08
Granted	754,474	3.91
Vested	(345,595)	4.81
Forfeited	—	—
Balance at end of year [1]	500,850	$ 4.42

[1] Excludes 78,864 units at the beginning of the year and 346,777 units at the end of year that have vested due to retirement eligibility, but have not yet been settled or converted to common shares.

As of December 31, 2013, we had $1.5 million of unrecognized compensation cost attributable to unvested restricted stock units. We expect that cost to be recognized over a weighted-average period of 1.1 years. The total grant-date fair values of restricted stock units that vested in 2013, 2012 and 2011 were $1.7 million, $1.4 million and $0.9 million, respectively.

Performance-Based Restricted Stock Units

In May 2013 and February 2012, we granted PBRSUs to certain executive officers. Vested PBRSUs are payable solely in cash on the third anniversary of the date of grant based upon the achievement of specified market-based performance metrics with respect to each of a one-year, two-year and three-year performance period, in each case commencing on the date of grant. The number of PBRSUs vested can range from 0% to 200% of the initial grant. The PBRSUs do not have voting rights and do not participate in dividends.

Except as noted below, if the grantee's employment terminates for any reason prior to the third anniversary of the grant date, then the grantee's PBRSUs will be forfeited and no cash will be payable with respect to any PBRSUs. If the grantee is or becomes retirement eligible and his or her employment terminates for any reason other than cause prior to the third anniversary of the grant date, then all of the grantee's PBRSUs will vest and become payable in the amount and at the time the PBRSUs would have otherwise vested and been payable. If the grantee dies or becomes disabled prior to the third anniversary of the grant date, a pro-rated share (based on the number of days employed during the three-year vesting period) of the PBRSUs will vest and the grantee will be paid for such PBRSUs at the target percentage at the end of the end of the original three-year vesting period. In the event of a change in control of us, all of the grantee's PBRSUs will immediately vest and the grantee will be paid for such PBRSUs following the change in control at the target percentage (regardless of our actual market-based performance) and using the value of our common stock on the effective date of the change in control (calculated as the closing price of our common stock on the effective date of the change in control).

The compensation cost of the PBRSUs is based on the fair value derived from a Monte Carlo model. The Monte Carlo model is a binomial valuation model that utilizes certain assumptions, including expected volatility, dividend yield, risk-free interest rates and a measure of total shareholder return.

The ranges for the assumptions used in the Monte Carlo model for the PBRSUs granted in 2013 and 2012 are as follows:

	2013	2012
Expected volatility	51.3% to 66.7%	29.3% to 78.0%
Dividend yield	0.0% to 0.0%	0.0% to 5.3%
Risk-free interest rate	0.01% to 0.78%	0.02% to 0.43%

The following table summarizes activity for our most recent fiscal year with respect to PBRSUs:

	Performance-Based Restricted Stock Units	Weighted-Average Fair Value
Balance at beginning of year	200,824	$ 6.67
Granted	360,486	4.91
Forfeited	—	—
Balance at end of year	561,310	$ 16.07

As of December 31, 2013, $4.8 million, which represents the fair value of the outstanding PBRSUs, is included in the Other liabilities caption on our Consolidated Balance Sheets.

15. Restructuring Activities

In 2012, we completed an organizational restructuring in conjunction with the sale of our natural gas assets in West Virginia, Kentucky and Virginia. We terminated approximately 30 employees and closed our regional office in Canonsburg, Pennsylvania. We recorded a charge in connection with the early termination of the lease of that office. In addition, we have a contractual commitment for certain firm transportation capacity in the Appalachian region that expires in 2022 and, as a result of the sale, we no longer have production to satisfy this commitment. While we intend to sell our unused firm transportation in the future to the extent possible, we recognized an obligation representing the liability for estimated discounted future net cash outflows over the remaining term of the contract. The undiscounted amount payable on an annual basis for the each of the next five years is $2.7 million and a combined amount of $10.3 million will be payable for 2019 through expiration in 2022.

During 2011, we completed an organizational restructuring due primarily to our sale of Arkoma Basin properties and consolidation of certain operations functions in our Houston, Texas location. We terminated approximately 40 employees and closed our regional office in Tulsa, Oklahoma. Accordingly, we recorded a charge and recognized an obligation in connection with the long-term lease of that office. In addition to the accrual of these costs, we adjusted the lease obligation associated with the Tulsa office as a result of a change in estimated sub-lease rental income.

The following table summarizes our restructuring and exit activity-related obligations and the changes therein for the years ended December 31:

	2013	2012	2011
Balance at beginning of period	$ 17,263	$ 576	$ 64
Employee, office and other costs accrued, net	7	1,284	2,351
Firm transportation charge	—	17,332	—
Accretion of obligations	1,674	570	—
Cash payments, net	(2,854)	(2,499)	(1,839)
Balance at end of period	$ 16,090	$ 17,263	$ 576

Restructuring charges are included in the General and administrative caption on our Consolidated Statements of Operations. The initial charge for the firm transportation commitment was presented as a separate caption on our Consolidated Statements of Operations for the year ended December 31, 2012. The accretion of this obligation, net of any recoveries from the periodic sale of our contractual capacity, is charged as an offset to Other revenue.

The current portion of these restructuring and exit cost obligations is included in the Accounts payable and accrued expenses caption and the noncurrent portion is included in the Other liabilities caption on our Consolidated Balance Sheets. As of December 31, 2013, $2.7 million of the total obligations are classified as current while the remaining $13.4 million are classified as noncurrent.

16. Impairments

The following table summarizes impairment charges recorded during the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Oil and gas properties	$ 132,224	$ 103,417	$ 104,688
Other - tubular inventory and well materials	—	1,067	—
	$ 132,224	$ 104,484	$ 104,688

The following table summarizes the aggregate fair values of the assets described below, by asset category and the classification of inputs within the fair value measurement hierarchy, at the respective dates of impairment:

	Fair Value Measurement	Level 1	Level 2	Level 3
Year ended December 31, 2013:				
Long-lived assets held for use	$ 93,945	$ —	$ —	$ 93,945
Year ended December 31, 2012:				
Long-lived assets held for use	$ 14,801	$ —	$ —	$ 14,801
Long-lived assets sold during the year	96,099	—	—	96,099
Year ended December 31, 2011:				
Long-lived assets held for use	$ 26,625	—	—	26,625
Long-lived assets sold during the year	30,342	—	—	30,342

In 2013, we recognized oil and gas impairments of $121.8 million in the Granite Wash in the Mid-Continent, $9.5 million in the Marcellus Shale in Pennsylvania and $0.9 million in the Selma Chalk in Mississippi, in each case due primarily to market declines in current and expected future commodity prices. In 2012, we recognized a $28.4 million impairment of our assets in West Virginia, Kentucky and Virginia triggered by the expected disposition of these properties, and a $75.0 million impairment of our Marcellus Shale assets due primarily to market declines in natural gas prices and the resultant reduction in proved natural gas reserves. In 2012, we also recognized an impairment of certain tubular inventory and well materials due primarily to declines in asset quality. In 2011, we recognized an impairment of our Arkoma Basin assets for $71.1 million, which was triggered by the expected disposition of these properties. Also during 2011, we recognized impairments of our horizontal coal bed methane properties in the Appalachian region for $26.6 million and certain dry-gas properties in Mississippi for $6.8 million, in each case due primarily to market declines in gas prices.

17. Interest Expense

The following table summarizes the components of interest expense for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Interest on borrowings and related fees	$ 80,263	$ 56,080	$ 51,392
Accretion of original issue discount [1]	431	1,367	3,427
Amortization of debt issuance costs	3,413	2,695	3,380
Capitalized interest [2]	(5,266)	(803)	(1,983)
	$ 78,841	$ 59,339	$ 56,216

[1] Includes accretion of original issue discount attributable to the 2016 Senior Notes that were retired in 2013 and the 4.50% Convertible Senior Subordinated Notes due 2012 (“Convertible Notes”) that were retired in 2012.

[2] The increase in capitalized interest in 2013 is attributable to a significant increase in qualifying activities that are in process to bring our Eagle Ford Shale unproved and proved undeveloped properties, including those acquired in the 2013 EF Acquisition, into production.

18. Earnings per Share

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings per share for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Net loss	$ (143,070)	$ (104,589)	$ (132,915)
Less: Preferred stock dividends [1]	(6,900)	(1,687)	—
Loss attributable to common shareholders - Basic and Diluted	$ (149,970)	$ (106,276)	$ (132,915)
Weighted-average shares - Basic	62,335	47,919	45,784
Effect of dilutive securities [2]	—	—	—
Weighted-average shares - Diluted	62,335	47,919	45,784

[1] Preferred stock dividends were excluded for diluted earnings per share as the assumed conversion of the 6% Preferred Stock would have been anti-dilutive.

[2] For 2013, 2012 and 2011, approximately 19.8 million, 19.2 million and 0.1 million potentially dilutive securities, including the 6% Preferred Stock, Convertible Notes, stock options, restricted stock and restricted stock units had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share.

Supplemental Quarterly Financial Information (Unaudited - see accompanying accountants' report)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013				
Revenues	$ 83,198	$ 109,655	$ 121,613	$ 117,002
Operating income (loss) [1]	$ (2,959)	$ 3,240	$ (107,788)	$ 15,461
Loss attributable to common shareholders [2]	$ (18,108)	$ (27,163)	$ (100,625)	$ (4,074)
Loss per share - Basic [3]	$ (0.33)	$ (0.43)	$ (1.54)	$ (0.06)
Loss per share - Diluted [3]	$ (0.33)	$ (0.43)	$ (1.54)	$ (0.06)
Weighted-average shares outstanding:				
Basic	55,341	62,899	65,465	65,490
Diluted	55,341	62,899	65,465	65,490
2012				
Revenues	$ 84,411	$ 76,845	$ 77,699	$ 78,194
Operating loss [4]	$ (3,422)	$ (38,043)	$ (24,485)	$ (81,141)
Loss attributable to common shareholders	$ (11,899)	$ (5,638)	$ (32,611)	$ (56,128)
Loss per share - Basic [3]	$ (0.26)	$ (0.12)	$ (0.71)	$ (1.05)
Loss per share - Diluted [3]	$ (0.26)	$ (0.12)	$ (0.71)	$ (1.05)
Weighted-average shares outstanding:				
Basic	45,945	46,030	46,050	53,607
Diluted	45,945	46,030	46,050	53,607

[1] Includes impairments of oil and gas properties of $132.2 million during the quarter ended September 30, 2013.
[2] Includes a loss on extinguishment of debt of $29.2 million attributable to the Tender Offer and the Redemption of the 2016 Senior Notes during the quarter ended June 30, 2013.
[3] The sum of the quarters may not equal the total of the respective year's earnings per common share due to changes in weighted-average shares outstanding throughout the year.
[4] Includes impairments of oil and gas properties of $28.6 million, $0.7 million and $75.2 million during the quarters ended June 30, 2012, September 30, 2012 and December 31, 2012, respectively. Also included is a charge of $17.3 million attributable to a loss on a firm transportation commitment during the quarter ended September 30, 2012.

Supplemental Information on Oil and Gas Producing Activities (Unaudited - see accompanying accountants' report)

Oil and Gas Reserves

All of our proved oil and gas reserves are located in the continental United States. The estimates of our proved oil and gas reserves were prepared by our independent third party engineers, Wright & Company, Inc. utilizing data compiled by us. Wright & Company, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petro physicists. Our Vice President, Operations & Engineering is primarily responsible for overseeing the preparation of the reserve estimate by Wright & Company, Inc.

Reserve engineering is a process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, NGLs and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future prices for these commodities may all differ from those assumed. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available.

The following table sets forth our estimate of net quantities of proved reserves, including changes therein and proved developed and proved undeveloped reserves for the periods presented:

Proved Developed and Undeveloped Reserves	**Oil (MBbl)**	**NGLs (MBbl)**	**Natural Gas (MMcf)**	**Total Equivalents (MBOE)**
December 31, 2010	8,082	24,713	744,982	156,959
Revisions of previous estimates	(2,367)	(3,047)	(61,165)	(15,608)
Extensions, discoveries and other additions	9,669	732	56,345	19,792
Production	(1,283)	(907)	(33,410)	(7,758)
Purchase of reserves	20	—	1	20
Sale of reserves in place	(42)	—	(36,840)	(6,182)
December 31, 2011	14,079	21,491	669,913	147,223
Revisions of previous estimates	(439)	(2,495)	(154,372)	(28,662)
Extensions, discoveries and other additions	13,444	2,578	13,405	18,255
Production	(2,252)	(884)	(20,261)	(6,513)
Purchase of reserves	39	1	6	41
Sale of reserves in place	(20)	—	(101,172)	(16,882)
December 31, 2012	24,851	20,691	407,519	113,462
Revisions of previous estimates	(4,400)	(5,298)	(111,939)	(28,355)
Extensions, discoveries and other additions	34,077	6,510	36,297	46,637
Production	(3,435)	(983)	(14,435)	(6,824)
Purchase of reserves	9,604	1,046	4,651	11,425
Sale of reserves in place	—	—	—	—
December 31, 2013	60,697	21,966	322,093	136,345
Proved Developed Reserves:				
December 31, 2011	7,075	9,395	330,552	71,562
December 31, 2012	10,472	8,266	169,449	46,980
December 31, 2013	19,306	8,541	163,161	55,041
Proved Undeveloped Reserves:				
December 31, 2011	7,004	12,096	339,361	75,661
December 31, 2012	14,379	12,425	238,070	66,482
December 31, 2013	41,391	13,425	158,932	81,304

The following is a discussion and analysis of the significant changes in our proved reserve estimates for the periods presented:

Year Ended December 31, 2013

We had downward revisions of 28.4 MMBOE primarily as a result of the following: (i) downward revisions of 20.1 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Haynesville Shale (8.3 MMBOE), Cotton Valley (7.1 MMBOE), Selma Chalk (3.7 MMBOE) and all other locations combined, including the Granite Wash and Marcellus Shale (1.0 MMBOE), (ii) downward revisions in the Eagle Ford Shale due primarily to the elimination of certain locations (2.2 MMBOE) and revisions to existing locations (2.5 MMBOE) attributable to changes in our development plans including the effects of reduced down-spacing, (iii) downward revisions of 5.8 MMBOE due to well performance issues, primarily in the Haynesville Shale, the Cotton Valley and the Selma Chalk and (iv) the effects of non-participation and lease expirations (0.3 MMBOE) partially offset by (v) favorable price revisions (2.5 MMBOE) for oil and natural gas. We added 46.6 MMBOE due primarily to the drilling of 59 gross (34.6 net) wells and the addition of proved undeveloped locations as well as 11.4 MMBOE from the 2013 EF Acquisition in the Eagle Ford Shale.

Year Ended December 31, 2012

We had downward revisions of 28.7 MMBOE primarily as a result of the following: (i) downward revisions of 5.0 MMBOE due to well performance issues, interest changes and economic limits due to operating conditions, including lease operating expense and basis differentials, primarily in the Selma Chalk, the Granite Wash, the Cotton Valley, and the Haynesville and Marcellus Shales, (ii) downward revisions of 15.0 MMBOE due to lower natural gas prices which significantly reduced the number of proved undeveloped locations in the Marcellus Shale and Selma Chalk and (iii) downward revisions of 8.7 MMBOE due to the removal of 38 proved undeveloped locations that would not be developed within five years primarily in the Selma Chalk, the Cotton Valley and the Haynesville Shale. We added 18.3 MMBOE due primarily to the drilling of 18 wells and the addition of 48 proved undeveloped locations in the Eagle Ford Shale.

Year Ended December 31, 2011

We had downward revisions of 15.6 MMBOE primarily as a result of the following: (i) downward revisions of 12.0 MMBOE due to well performance issues, interest changes and economic limits attributable to operating conditions particularly in the Granite Wash, Cotton Valley and Selma Chalk, (ii) downward revisions of 1.7 MMBOE due to lower condensate yield in the Granite Wash, (iii) downward revisions of 1.5 MMBOE attributable to the elimination of proved undeveloped locations particularly in the Haynesville Shale in East Texas, (iv) downward revisions of 0.8 MMBOE due to lower natural gas prices and upward revisions of 0.5 MMBOE due to higher gas processing yields in the Haynesville Shale and Granite Wash. We added 19.8 MMBOE due primarily to an increase of 9.0 MMBOE due to the drilling of three Marcellus Shale wells and two Granite Wash wells as well as the addition of 25 proved undeveloped locations in the Marcellus Shale and Selma Chalk. We also drilled 28 Eagle Ford Shale wells and added 26 proved undeveloped locations which resulted in an increase of 10.8 MMBOE.

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table sets forth capitalized costs related to our oil and gas producing activities and accumulated DD&A for the periods presented:

	As of December 31,		
	2013	**2012**	**2011**
Oil and gas properties:			
Proved	$ 460,255	$ 240,217	$ 277,987
Unproved	101,520	60,746	120,288
Total oil and gas properties	561,775	300,963	398,275
Other property and equipment:			
Wells, equipment and facilities	2,593,700	2,107,061	2,081,103
Support equipment	3,504	6,815	6,645
Total other property and equipment	2,597,204	2,113,876	2,087,748
Total capitalized costs relating to oil and gas producing activities	3,158,979	2,414,839	2,486,023
Accumulated depreciation and depletion	(924,667)	(693,123)	(710,948)
Net capitalized costs relating to oil and gas producing activities [1]	$ 2,234,312	$ 1,721,716	$ 1,775,075

[1] Excludes property and equipment attributable to our corporate operations including certain capitalized hardware, software and office furniture and fixtures.

Costs Incurred in Certain Oil and Gas Activities

The following table summarizes costs incurred in our oil and gas property acquisition, exploration and development activities for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Proved property acquisition costs [1]	$ 277,888	$ —	$ —
Unproved property acquisition costs [1]	188,202	27,775	47,877
Exploration costs [2]	16,833	50,883	82,080
Development costs and other [3]	422,540	305,693	320,263
Total costs incurred	$ 905,463	$ 384,351	$ 450,220

[1] Includes $277.9 million and $119.7 million of proved and unproved property acquisition costs attributable to the 2013 EF Acquisition.

[2] Includes geological and geophysical costs of $2.9 million, $0.8 million and $11.2 million and delay rentals of $0.7 million, $0.6 million and $2.2 million during the years ended December 31, 2013, 2012 and 2011, respectively, as well as dry hole costs of $18.9 million and drilling rig standby charges of $4.6 million during the year ended December 31, 2011 that were charged to expense.

[3] Does not include non-cash ARO assets of $1.7 million, $0.1 million and $0.2 million that were added to capitalized costs relating to oil and gas producing activities during the years ended December 31, 2013, 2012 and 2011, respectively.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Future cash inflows were computed by applying the average prices of oil and gas during the 12-month period prior to the period end, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the period and estimated costs as of that fiscal year end, to the estimated future production of proved reserves. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pre-tax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

The standardized measure of discounted future net cash flows is not intended, and should not be interpreted, to represent the fair value of our oil and gas reserves. An estimate of the fair value would also consider, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and cost, and a discount factor more representative of economic conditions and risks inherent in reserve estimates. Accordingly, the changes in standardized measure reflected above do not necessarily represent the economic reality of such transactions.

Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu with the representative price of natural gas adjusted for basis premium and energy content to arrive at the appropriate net price. NGL prices were estimated as a percentage of the base crude oil price. The following table summarizes the price measurements utilized, by product, with respect to our estimates of proved reserves as well as in the determination of the standardized measure of the discounted future net cash flows for the periods presented:

	Crude Oil	NGLs	Natural Gas
	$ per Bbl	$ per Bbl	$ per MMBtu
As of December 31, 2011	$ 92.22	$ 50.69	$ 3.95
As of December 31, 2012	$ 102.24	$ 39.48	$ 2.47
As of December 31, 2013	$ 103.11	$ 31.10	$ 3.47

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Future cash inflows	$ 8,059,089	$ 4,365,357	$ 5,032,915
Future production costs	(2,193,925)	(1,206,478)	(1,374,658)
Future development costs	(2,111,918)	(1,118,859)	(1,091,100)
Future net cash flows before income tax	3,753,246	2,040,020	2,567,157
Future income tax expense	(973,680)	(548,132)	(665,751)
Future net cash flows	2,779,566	1,491,888	1,901,406
10% annual discount for estimated timing of cash flows	(1,515,788)	(994,014)	(1,246,910)
Standardized measure of discounted future net cash flows	$ 1,263,778	$ 497,874	$ 654,496

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table summarizes the changes in the standardized measure of the discounted future net cash flows attributable to our proved reserves for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Sales of oil and gas, net of production costs	$ (359,989)	$ (254,388)	$ (234,211)
Net changes in prices and production costs	49,214	(207,045)	(25,398)
Extensions, discoveries and other additions	995,858	355,495	361,284
Development costs incurred during the period	79,964	119,706	44,741
Revisions of previous quantity estimates	(260,440)	(196,152)	(113,188)
Purchases of reserves-in-place	219,414	1,156	308
Sale of reserves-in-place	—	(116,151)	(37,474)
Accretion of discount	69,247	87,441	87,815
Net change in income taxes	(258,254)	25,312	16,818
Other changes	230,890	28,004	(87,618)
Net increase (decrease)	765,904	(156,622)	13,077
Beginning of year	497,874	654,496	641,419
End of year	$ 1,263,778	$ 497,874	$ 654,496

Item 9 Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2013. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported accurately and on a timely basis. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2013, such disclosure controls and procedures were effective.

(b) Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over our financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. This evaluation was completed based on the framework established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2013, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has issued an attestation report on the internal control over financial reporting as of December 31, 2013, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

No changes were made in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B Other Information

There was no information that was required to be disclosed by us on a Current Report on Form 8-K during the fourth quarter of 2013 which we did not disclose.

Part III

Item 10 Directors, Executive Officers and Corporate Governance

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11 Executive Compensation

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13 Certain Relationships and Related Transactions, and Director Independence

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14 Principal Accountant Fees and Services

In accordance with General Instruction G(3), reference is hereby made to the Company's definitive proxy statement to be filed within 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Part IV

Item 15 Exhibit and Financial Statement Schedules

The following documents are included as exhibits to this Annual Report on Form 10-K. Those exhibits incorporated by reference are indicated as such in the parenthetical following the description. All other exhibits are included herewith.

(1)	Financial Statements — The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 51 of this Annual Report on Form 10-K.
(2.1)	Stock Purchase Agreement, dated as of April 2, 2013, by and among Magnum Hunter Resources Corporation, as seller, Penn Virginia Oil & Gas Corporation, as buyer and Penn Virginia Corporation, as additional party and guarantor (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on April 10, 2013).
(2.1.1)	Amendment to Stock Purchase Agreement, dated as of April 8, 2013, by and among Magnum Hunter Resources Corporation, Penn Virginia Oil & Gas Corporation and Penn Virginia Corporation (incorporated by reference to Exhibit 2.2 to Registrant's Current Report on Form 8-K filed on April 10, 2013).
(3.1)	Restated Articles of Incorporation of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on July 30, 2013).
(3.2)	Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on September 27, 2013).
(4.1)	Senior Indenture dated June 15, 2009 among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 16, 2009).
(4.1.1)	First Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated June 15, 2009, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(4.1.2)	Second Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated April 4, 2011, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2011).
(4.1.3)	Form of Note for 10.375% Senior Notes due 2016 (incorporated by reference to Annex A to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A filed on June 18, 2009).
(4.1.4)	Third Supplemental Indenture relating to the 7.25% Senior Notes due 2019, dated April 13, 2011, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(4.1.5)	Form of Note for 7.25% Senior Notes due 2019 (incorporated by reference to Annex A to Exhibit 4.3 to Registrant's Current Report on Form 8-K filed on April 14, 2011).
(4.1.6)	Fourth Supplemental Indenture relating to the 8.500% Senior Notes due 2020, dated April 24, 2013, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.1.7)	Form of 8.500% Senior Notes due 2020 (incorporated by reference to Exhibit 4.3 contained in Exhibit 1 to Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.1.8)	Fifth Supplemental Indenture relating to the 10.375% Senior Notes due 2016, dated April 24, 2013, among Penn Virginia Corporation, as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.6 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.2)	Deposit Agreement, dated October 17, 2012, among Penn Virginia Corporation, American Stock Transfer & Trust Company, LLC and the holders from time to time of the depositary shares described therein (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).
(4.2.1)	Form of depositary receipt representing the Depositary Shares (incorporated by reference to Exhibit A to Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on October 17, 2012).
(4.3)	Registration Rights Agreement, dated April 24, 2013, among Penn Virginia Corporation, the several guarantors named therein and RBC Capital Markets, LLC, as representatives of the initial purchasers named therein (incorporated by reference to Exhibit 4.4 to Registrant's Current Report on Form 8-K filed on April 29, 2013).
(4.4)	Registration Rights, Lock-Up and Buy-Back Agreement dated April 24, 2013, between Penn Virginia Corporation and Magnum Hunter Resources Corporation (incorporated by reference to Exhibit 4.5 to Registrant's Current Report on Form 8-K filed on April 29, 2013).

(10.1)	Credit Agreement dated as of September 28, 2012 among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 2, 2012).
(10.1.1)	Waiver and First Amendment to Credit Agreement dated as of April 2, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 3, 2013).
(10.1.2)	Waiver and Second Amendment to Credit Agreement dated as of April 2, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 11, 2013).
(10.1.3)	Assignment and Third Amendment to Credit Agreement dated as of May 20, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 3, 2013).
(10.1.4)	Assignment and Fourth Amendment to Credit Agreement dated as of October 28, 2013 by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 30, 2013).
(10.2)	Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.2.1)	Amendment 2009-1 to the Penn Virginia Corporation Supplemental Employee Retirement Plan (incorporated by reference to Exhibit 10.4.1 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2011).*
(10.3)	Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 29, 2007).*
(10.3.1)	Amendment One to the Penn Virginia Corporation Amended and Restated Non-Employee Directors Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 6, 2011).*
(10.4)	Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.29 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007). *
(10.4.1)	Form of Agreement for Deferred Common Stock Unit Grants under the Penn Virginia Corporation Fifth Amended and Restated 1995 Directors' Compensation Plan (incorporated by reference to Exhibit 10.30 to Registrant's Annual Report on Form 10-K for the year ended December 31, 2007).*
(10.5)	Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.1)	Form of Agreement for Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.2)	Form of Agreement for Performance Based Restricted Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Incentive Plan (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.3)	Form of Agreement for Stock Option Grants under the Penn Virginia Corporation Amended and Restated 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on May 3, 2013).*
(10.5.4)	Form of Agreement for Deferred Common Stock Unit Awards under the Penn Virginia Corporation 2013 Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 30, 2013).*
(10.6)	Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and H. Baird Whitehead (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.7)	Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.8)	Amended and Restated Executive Change of Control Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*

(10.9)	Executive Change of Control Severance Agreement dated January 29, 2013 between Penn Virginia Corporation and John A. Brooks (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on February 1, 2013). *
(10.10)	Amended and Restated Change of Location Severance Agreement dated December 20, 2012 between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on December 21, 2012).*
(10.11)	Penn Virginia Corporation 2011 Annual Incentive Cash Bonus and Long-Term Equity Compensation Guidelines (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K/A filed on February 7, 2013).*
(10.12)	Employment Retention Agreement dated August 9, 2011 between Penn Virginia Corporation and John A. Brooks. *
(10.13)	Guaranty, dated as of April 2, 2013, by Penn Virginia Corporation in favor of Magnum Hunter Resources Corporation (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on April 10, 2013).
(10.14)	Purchase and Sale Agreement dated December 13, 2013, by and among Penn Virginia Oil & Gas, L.P., Ted Collins, Jr., Plein Sud Holdings, LLC as sellers and HPIP LaVaca, LLC as buyer.
(12.1)	Statement of Computation of Ratio of Earnings to Fixed Charges and Preferred Dividends Calculation.
(21.1)	Subsidiaries of Penn Virginia Corporation.
(23.1)	Consent of KPMG LLP.
(23.2)	Consent of Wright & Company, Inc.
(31.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2)	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(99.1)	Report of Wright & Company, Inc. dated January 27, 2014 concerning evaluation of oil and gas reserves.
(101.INS)	XBRL Instance Document
(101.SCH)	XBRL Taxonomy Extension Schema Document
(101.CAL)	XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF)	XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB)	XBRL Taxonomy Extension Label Linkbase Document
(101.PRE)	XBRL Taxonomy Extension Presentation Linkbase Document

* Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PENN VIRGINIA CORPORATION

By: /s/ STEVEN A. HARTMAN
Steven A. Hartman
Senior Vice President and Chief Financial Officer

February 24, 2014

By: /s/ JOAN C. SONNEN
Joan C. Sonnen
Vice President, Chief Accounting Officer and Controller
(Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ EDWARD B. CLOUES, II **Edward B. Cloues, II**	Chairman of the Board and Director	February 24, 2014
/s/ JOHN U. CLARKE **John U. Clarke**	Director	February 24, 2014
/s/ STEVEN A. HARTMAN **Steven A. Hartman**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2014
/s/ STEVEN W. KRABLIN **Steven W. Krablin**	Director	February 24, 2014
/s/ MARSHA R. PERELMAN **Marsha R. Perelman**	Director	February 24, 2014
/s/ JOAN C. SONNEN **Joan C. Sonnen**	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 24, 2014
/s/ H. BAIRD WHITEHEAD **H. Baird Whitehead**	Director and President and Chief Executive Officer (Principal Executive Officer)	February 24, 2014
/s/ GARY K. WRIGHT **Gary K. Wright**	Director	February 24, 2014

Exhibit 10.12

PENN VIRGINIA CORPORATION

H Baird Whitehead
President and
Chief Executive Officer

August 9, 2011

John A. Brooks
Katy, TX

RE: Employment Retention

Dear John:

Penn Virginia Corporation (the "Company") desires to retain you as an employee of the Company and, accordingly, agrees as follows:

1. Retention Payment. If you remain employed by the Company from the date hereof until the second anniversary of the date hereof (the "Retention Term"), the Company will pay to you a lump sum of $175,000, less applicable taxes (the "Retention Payment"), by not later than 30 days after the last day of the Retention Term.

2. Termination Without Cause. In the event that the Company terminates your employment during the Retention Term for any reason other than Cause (as defined below), the Company will pay the Retention Payment to you by not later than 30 days after the date of such termination subject to your execution (and non-revocation within eight days thereafter) and delivery to the Company of a release in the form attached as Exhibit A hereto with such changes as the Company determines must be made to comply with applicable law at the time of such execution.

For purposes of this Agreement, the term "Cause" shall mean (i) the willful and continued failure by you to substantially perform your duties with the Company, (ii) your inability to perform your duties with the Company for at least 90 days due to physical or mental impairment, (iii) you willfully engage in misconduct materially and demonstrably injurious to the Company or (iv) you commit one or more significant acts of dishonesty in regard to the Company.

3. Miscellaneous.

a. Any dispute arising under this Agreement, or related in any way to the term of same, will be governed by the laws of the Commonwealth of Pennsylvania, without regard to choice of law principles.

b. This Agreement may be executed in counterparts by facsimile, all of which taken together will constitute an instrument enforceable and binding upon the parties.

c. This Agreement will be construed as a whole according to its fair meaning. It will not be construed strictly for or against you or the Company.

d. The provisions of this Agreement are severable, and if for any reason any part hereof is found to be unenforceable, the remaining provisions will be enforced in full.

e. We intend this Agreement to be exempt from Section 409A of the Internal Revenue Code of 1986, as amended, pursuant to the short term deferred exception.

f. Nothing in this Agreement shall alter your status of employment, which we agree is at will.

g. This Agreement will be binding on the Company's successors and assigns.

To indicate that you agree with the terms of this Agreement, please sign in the space below.

Sincerely,

/s/ H. Baird Whitehead
H. Baird Whitehead
President and
Chief Executive Officer

AGREED TO
This 17th day of August, 2011

/s/ John A. Brooks
John A. Brooks

Exhibit 10.14

Execution Copy

PURCHASE AND SALE AGREEMENT

DATED AS OF DECEMBER 13, 2013

AMONG

PENN VIRGINIA OIL & GAS, L.P.,

TED COLLINS, JR.

AND

PLEIN SUD HOLDINGS, LLC

AS SELLERS

AND

HPIP LAVACA, LLC

AS BUYER

Table of Contents

Exhibits

Schedules

Schedule 1.1(e) Permits
Schedule 2.1 As-Built Maps Costs
Schedule 2.4 Sellers' Pro Rata Shares
Schedule 4.1(c) Individual Seller Violations
Schedule 4.2(b) Consents
Schedule 4.2(c) Proceedings
Schedule 4.2(d) Violations
Schedule 5.3 Permitted Capital Expenditures
Schedule 5.4 Consents
Schedule 5.12 Bonds
Schedule 5.18 Necessary ROWs

PURCHASE AND SALE AGREEMENT

This PURCHASE AND SALE AGREEMENT (this "Agreement"), is made and entered into this 13th day of December, 2013, by and among Penn Virginia Oil & Gas, L.P., a Texas limited partnership, Ted Collins, Jr., an individual, and Plein Sud Holdings, LLC, a Texas limited liability company (each, a "Seller" and collectively, "Sellers"), and HPIP Lavaca, LLC, a Delaware limited liability company (" Buyer"), and, solely for the purposes of Article 11, ArcLight Energy Partners Fund V, L.P., a Delaware limited partnership ("Buyer Guarantor"). Sellers and Buyer may be referred to herein individually as a "Party" or collectively as the " Parties."

RECITALS

WHEREAS, Sellers desire to sell, assign and transfer to Buyer, and Buyer desires to purchase from Sellers, the Purchased Assets (as defined in Section 1.1 below) in accordance with the terms and conditions set forth herein;

NOW, THEREFORE, in consideration of the mutual covenants and promises contained in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby specifically acknowledged, and intending to be legally bound hereby, Sellers and Buyer hereby agree as follows:

ARTICLE 1
PURCHASE AND SALE

1.1 Purchase and Sale. Subject to the terms and conditions hereof, at the Closing (as defined in Section 3.1 below), each Seller shall sell, assign, transfer and deliver to Buyer, and Buyer shall purchase and acquire from such Seller, all right, title and interest of such Seller in, to and under the following assets (collectively, the "Purchased Assets"):

(a) the natural gas gathering assets owned by Sellers and existing in Gonzales and Lavaca Counties, Texas and generally described on Schedule 1.1(a), together with all gathering lines, pipelines, gas and liquid treating and conditioning facilities, compressor stations, pipe, scrubbers, dehydration units, tanks, traps, cathodic protection equipment, meters, recorders, valves, fittings, equipment, personal property and improvements used or held for use exclusively in connection with the ownership, use and operation of such gathering assets, including such real property and surface and use rights as are necessary for the ownership, use or operation of the such gathering assets and related facilities and equipment (collectively, the "Gathering Assets"); *provided, however,* that the Gathering Assets shall not include any drip tanks;

(b) such surface leases, subleases, licenses, easements and rights-of-way used or held for use exclusively in connection with the ownership, use or operation of the Gathering Assets, including those described on Schedule 1.1(b) (collectively, the "Rights of Ways");

(c) all owned real property used or held for use exclusively in connection with the ownership, use or operation of the Gathering Assets, together with all buildings, structures and fixtures existing thereon, including that real property described on Schedule 1.1(c) (collectively, the "Fee Property");

(d) with respect to rights and obligations from and after the Effective Time, all contracts and agreements used or held for use exclusively in connection with the ownership, use or operation of the Gathering Assets (other than the Rights of Way), including those described on Schedule 1.1(d) (collectively, the "Contracts");

(e) to the extent assignable under applicable Laws and Regulations (as defined in Section 4.2(d) below), all permits, licenses, variances, exemptions, orders, franchises, registrations, approvals and authorizations obtained from any Governmental Authority (as defined in Section 4.2(b) below), and all pending applications therefor, used or held for use exclusively in connection with the ownership, use and operation of the Gathering Assets, including those described on Schedule 1.1(e) (collectively, the "Permits");

(f) all condensate and natural gas liquids tank fill and pipeline fill as of the Effective Time; and

(g) all files, books, records, information and data directly pertaining to the Purchased Assets in any Seller's possession or control or to which any Seller has a right, including contract, land, title, engineering, environmental, operating, accounting, regulatory, legal, business, marketing and other data (whether electronic or hard copy), files, documents, instruments, notes, papers, ledgers, journals, reports, abstracts, surveys, keys, lock combinations, computer access codes and similar information, maps, books, records and studies, but excluding any files, books, records, information and data (i) to the extent that the disclosure or transfer thereof is prohibited by third party agreement or applicable Laws and Regulations, (ii) relating to a Seller's business generally, (iii) constituting work product of a Seller's legal counsel (other than title opinions) and (iv) relating to the negotiation and consummation of the sale of the Purchased Assets (collectively, the "Records"); *provided, however,* that each Seller may retain copies of the Records as may be necessary for litigation, tax, accounting or auditing purposes or as otherwise may be required by applicable Laws and Regulations.

1.2 No Other Assets. Except for the Purchased Assets expressly described in Section 1.1 above, Sellers shall not sell, and Buyer shall not purchase, any other assets, properties, interests or rights of Sellers.

1.3 Assumed Liabilities. As of the Effective Time, Buyer shall assume all liabilities, duties, obligations and responsibilities of every kind whatsoever attributable to the Purchased Assets, whether known or unknown, whether attributable to the period of time before or after the Effective Time (collectively, the "Assumed Liabilities").

ARTICLE 2
PURCHASE PRICE

2.1 Purchase Price. The aggregate purchase price (the "Purchase Price") for the Purchased Assets shall be (a) One Hundred Million Dollars ($100,000,000) (the "Base Purchase Price"), plus (b) the amount, if any, of all capital costs and expenses in respect of the Purchased Assets paid by Sellers prior to the date upon which the Proposed Final Settlement Statement is due to Buyer pursuant to Section 2.3(b) and either (i) incurred after October 1, 2013 (the "Capital

Date") and prior to the date hereof as set forth on Schedule 5.3 or (ii) incurred between the date hereof and the Closing Date in accordance with Section 5.3(c)(vii) ((i) and (ii) collectively, the "Capital Adjustment"), minus (c) the amount, if any, of all costs and expenses incurred by Buyer to create "as-built" maps for the Purchased Assets as set forth on Schedule 2.1.

2.2 Purchase Price Allocation. As soon as practicable but no later than 90 days after the Closing Date, Buyer shall deliver to Sellers an allocation of the Base Purchase Price (and all other capitalizable costs) among the Purchased Assets (the "Initial Allocation" and any revision thereto as provided hereunder, the " Purchase Price Allocation"). Upon any adjustment to the Base Purchase Price or the Assumed Liabilities pursuant to the terms of this Agreement or upon any Assumed Liability that was contingent becoming fixed and ascertainable, capitalizable costs becoming fixed and ascertainable, or any purchase price adjustment due to indemnification, Buyer shall deliver to Sellers a proposed revision to the Purchase Price Allocation then in effect, which shall be consistent with the methodology used to prepare the Initial Allocation. Upon (i) Buyer's delivery of the Initial Allocation or (ii) Buyer's delivery of any proposed revision, Sellers shall have 10 business days to object to such proposed purchase price allocation. If the Sellers do not timely object, the proposed purchase price allocation shall become the Purchase Price Allocation. If the Sellers do timely object, the Parties shall negotiate in good faith to resolve such objection promptly; *provided, however,* that, if the Parties fail to agree on a new Purchase Price Allocation within 30 days of Buyer's notice of proposed revision, either Party may refer the proposed revision and the objection to Deloitte & Touche LLP (the "Audit Firm") and the resolution by such firm shall become the Purchase Price Allocation. The Parties shall each report the federal, state and local income and other tax consequences of the transactions contemplated by this Agreement (which for such purposes includes the Transaction Documents (as defined in Section 3.4 below)) in a manner consistent with the Purchase Price Allocation, including the preparation and filing of Form 8594 under Section 1060 of the Internal Revenue Code of 1986, as amended (or any successor form or successor provision of any future tax law, or any comparable provision of state or local tax law), with respect to their respective federal, state and local income tax returns for the taxable year that includes the Closing Date and shall not take any position contrary thereto in connection with any amended return.

2.3 Purchase Price Adjustments.

(a) No later than three days prior to the Closing, the Seller Representative (as defined in Section 9.1(a) below) shall prepare and deliver to Buyer a preliminary settlement statement prepared by the Seller Representative in accordance with this Agreement and generally accepted accounting principles consistently applied by Seller (the "Preliminary Settlement Statement"), which sets forth the Seller Representative's good faith estimate of the Capital Adjustment.

(b) As soon as practicable but no later than 90 days after the Closing, the Seller Representative shall prepare and deliver to Buyer a statement in the same form of and on the same basis as the Preliminary Settlement Statement (the "Proposed Final Settlement Statement"), which sets forth the Seller Representative's calculation of the final Purchase Price and each adjustment or payment that was not finally determined on the Preliminary Settlement Statement. Each Party shall, during normal business hours, grant and provide the other Party access to the Purchased Records in the possession or control of such Party for the purposes of conducting an audit of the information set forth in the Proposed Final Settlement Statement.

(c) Within 30 days following receipt by Buyer of the Proposed Final Settlement Statement, Buyer shall, if applicable, provide the Seller Representative with a written objection (a "Notice of Disagreement") detailing Buyer's objections, if any, to the Seller Representative's calculation of the final Purchase Price. To the extent such written notice is not delivered by Buyer within such time period, the Seller Representative's calculation of the final Purchase Price, and each component thereof, shall become final and binding upon the Parties.

(d) Any disagreement between Buyer and Sellers regarding the Seller Representative's calculation of the final Purchase Price that cannot be resolved within 30 days after the date of the Notice of Disagreement shall be resolved by Audit Firm, who shall calculate the final Purchase Price in a manner consistent with the Preliminary Settlement Statement and this Agreement in all respects. Sellers and Buyer shall each have an opportunity to present its position to the Audit Firm and shall cooperate with the Audit Firm in making available to it any records or work papers requested by the Audit Firm. The determination of the Audit Firm shall be expressly limited to the determination of the final Purchase Price, and the Audit Firm will not render any decision or have any authority to render a decision with respect to any other matter relating to this Agreement, including with respect to any alleged breach of a representation, warranty or covenant by any Party. In making such determination, the Audit Firm shall consider only those items and amounts in the Proposed Final Settlement Statement with which Buyer has disagreed and which are set forth in the Notice of Disagreement. In no event shall the final Purchase Price as determined by the Audit Firm be more favorable to Sellers than reflected on the Proposed Final Settlement Statement by the Seller Representative nor more favorable to Buyer than shown in the proposed changes set forth in the Notice of Disagreement. Buyer and Sellers shall use commercially reasonable efforts to cause the Audit Firm to render its decision within 15 business days after such points of disagreement are submitted to the Audit Firm. Subject to the provisions set forth in this Section 2.3(d), the decision of the Audit Firm shall be set forth in writing and shall be conclusive and binding on the Parties and subject to judicial enforcement. The fees charged by the Audit Firm shall be borne 50% by Buyer and 50% by Sellers, and each Party shall bear all of its own costs and expenses associated with the submission of any disputed matters to the Audit Firm.

(e) If the final Purchase Price, as determined pursuant to this Section 2.3, exceeds (i) the Base Purchase Price, plus (ii) the Seller Representative's good faith estimate of the Capital Adjustment (the " Closing Payment"), then Buyer shall pay to Sellers the amount of such excess. If the final Purchase Price, as determined pursuant to this Section 2.3, is less than the Closing Payment, then Sellers shall pay to Buyer the amount of such deficiency. Any payment shall be made within three days after the date the final Purchase Price is deemed to be finally determined pursuant to this Section 3.4 via wire transfer of immediately available funds to the account(s) designated in writing by the Party entitled to such payment.

2.4 Payment of Closing Payment. At the Closing, Buyer shall pay to each Seller such Seller's Pro Rata Share of the Closing Payment in cash by wire transfer of immediately available funds to an account(s) designated by such Seller. "Pro Rata Share" means, with respect to each Seller, the percentage set forth next to such Seller's name on Schedule 2.4.

2.5 Revenues and Expenses.

(a) The Parties acknowledge and agree that (i) Sellers shall bear all (A) operating expenses which are incurred in respect of the ownership, maintenance, use or operation of the Purchased Assets before the Effective Time and (B) capital expenses which are incurred in respect of the ownership, maintenance, use or operation of the Purchased Assets before the Capital Date (the "Seller Expenses"), (ii) Sellers shall be entitled to receive all proceeds collectible in respect of the ownership, use or operation of the Purchased Assets attributable to the period prior to the Effective Time (the "Pre-Closing Revenues"), (iii) Buyer shall bear all (A) operating expenses which are incurred in respect of the ownership, maintenance, use or operation of the Purchased Assets after the Effective Time and (B) capital expenses which are incurred in respect of the ownership, maintenance, use or operation of the Purchased Assets after the Capital Date (the "Buyer Expenses") and (iv) Buyer shall be entitled to receive all proceeds in respect of the ownership, use or operation of the Purchased Assets attributable to the period after the Effective Time (the "Post-Closing Revenues").

(b) In the event that Buyer pays any Seller Expenses, Sellers shall promptly reimburse Buyer for the amount of Seller Expenses paid by Buyer. In the event that Sellers receive any invoice or other statement relating to Buyer Expenses, Sellers shall promptly forward such invoice or statement to Buyer.

(c) Promptly following the Closing, Sellers shall irrevocably authorize, instruct and direct all account parties to the Contracts from whom Post-Closing Revenues are or may be owed to Buyer to make and deliver all payments relating thereto on or after the Closing Date to such location, bank and account as Buyer shall specify. In the event that any Seller or any of its Affiliates receives any Post-Closing Revenues, Sellers shall promptly deliver all such Post-Closing Revenues to Buyer. In the event that Buyer or any of its Affiliates receives any Pre-Closing Revenues, Buyer shall promptly deliver all such Pre-Closing Revenues to Sellers.

ARTICLE 3
CLOSING

3.1 Time and Place of Closing. The consummation of the transactions contemplated by this Agreement (the "Closing") shall take place at 10:00 a.m. in the offices of Penn Virginia Oil & Gas, L.P. (" PVOG") at 840 Gessner, Suite 800, Houston, Texas 77024, on or before the fifth day after which all conditions set forth in Sections 6.1 and 6.2 have been satisfied or waived by the appropriate Party, or at such other time and place as mutually agreed by Sellers and Buyer (the "Closing Date"), and shall be effective as of 12:01 a.m. (Central time) on the Closing Date (the "Effective Time").

3.2 Deliveries by Sellers at Closing. At the Closing, each Seller shall execute and deliver, or cause to be executed and delivered, or just delivered, where no execution is required, to Buyer:

(a) a conveyance, assignment and bill of sale assigning to Buyer all personal property (tangible and intangible) included in the Purchased Assets, in substantially the form attached hereto as Exhibit A (the "Conveyance");

(b) special warranty deeds in recordable form conveying to Buyer all Fee Property, in substantially the form attached hereto as Exhibit B (the "Deeds");

(c) partial assignments in recordable form assigning to Buyer an undivided, non-exclusive interest in all Rights of Way, in substantially the form attached hereto as Exhibit C (the "Partial Assignments");

(d) a gas gathering agreement, in substantially the form attached hereto as Exhibit D (the "Gathering Agreement");

(e) a transition services agreement, in substantially the form attached hereto as Exhibit E (the "Transition Agreement");

(f) an equity commitment letter, in substantially the form attached hereto as Exhibit F (the "Equity Commitment Letter");

(g) a receipt for the payment of the Closing Payment;

(h) a certificate signed by an officer of such Seller certifying that the conditions set forth in Sections 6.2(a) and 6.2(b) below have been satisfied;

(i) a certificate signed by an appropriate individual certifying that such Seller is not a foreign person in accordance with Section 1.1445-2(b) of the Treasury Regulations; and

(j) any other agreements, documents, certificates, approvals, consents or other instruments reasonably necessary to consummate the transactions contemplated by this Agreement.

3.3 Deliveries by Buyer at Closing. At the Closing, Buyer shall deliver the Closing Payment as provided in Section 2.4 above and shall execute and deliver or cause to be executed and delivered, or just delivered, where no execution is required, to the Seller Representative the following:

(a) the Conveyance;

(b) the Deeds;

(c) the Partial Assignments;

(d) the Gathering Agreement;

(e) the Transition Agreement;

(f) the Equity Commitment Letter;

(g) a certificate signed by an officer of Buyer certifying that the conditions set forth in Sections 6.1(a) and 6.1(b) below have been satisfied; and

(h) any other agreements, documents, certificates, approvals consents or other instruments reasonably necessary to consummate the transactions contemplated by this Agreement.

3.4 Transaction Documents. The agreements, instruments and documents referenced in this Article 3, together with this Agreement and such other agreements and instruments required to be delivered pursuant to this Agreement, are referred to herein collectively as the "Transaction Documents." The Transaction Documents to be executed and delivered by Sellers hereunder are referred to herein collectively as the "Seller Transaction Documents." The Transaction Documents to be executed and delivered by Buyer hereunder are referred to herein collectively as the "Buyer Transaction Documents."

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

4.1 Representations and Warranties of Each Seller. Each Seller, on its own behalf and not with respect to any other Seller, represents and warrants to Buyer as of the date hereof and as of the Closing Date that:

(a) Organization and Good Standing. Such Seller is (i) a limited partnership or limited liability company validly existing and in good standing under the laws of the State of Texas or (ii) an individual. Such Seller has all requisite limited partnership, personal or limited liability company power and authority to own, lease and operate the Purchased Assets and conduct its business as and where currently being conducted.

(b) Authorization and Enforceability. Such Seller has the requisite limited partnership, personal or limited liability company power and authority to execute, deliver and perform its obligations under this Agreement and the other Seller Transaction Documents and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance by such Seller of this Agreement and the other Seller Transaction Documents have been duly and validly authorized by all necessary limited partnership, personal or limited liability company action on the part of such Seller. This Agreement has been, and the other Seller Transaction Documents will be, duly and validly executed and delivered by such Seller. This Agreement is, and the other Seller Transaction Documents will be, the legal, valid and binding obligations of such Seller, enforceable against such Seller in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, moratorium, reorganization, fraudulent conveyance and similar laws affecting creditors' rights generally and except to the extent that general equitable principles may affect the availability of certain remedies.

(c) No Violation of Laws or Agreements. Except as set forth on Schedule 4.1(c), the execution, delivery and performance of this Agreement and the other Seller Transaction Documents by such Seller do not, and the consummation of the transactions contemplated hereby and thereby and the compliance by such Seller with any of the provisions hereof and thereof will not, conflict with, result in any violation of or default (with or without notice or lapse of time or both) under, give rise to a right of termination, cancellation or acceleration of any obligation or to the loss of a material benefit under, or result in the creation of any Lien (as defined in Section 4.1(d) below) on any of the Purchased Assets under, any provision of (i) the organizational documents of such Seller (if not an individual), (ii) any loan or credit agreement, note, bond, mortgage, indenture, contract, lease, permit, concession, franchise, license or other agreement or instrument applicable to such Seller or the Purchased Assets (other than any Right of Way or Contract) or (iii) any Laws and Regulations applicable to such Seller or the Purchased Assets, except, in the cases of clauses (ii) and (iii), for any such conflicts, violations, defaults, rights, losses or Liens that would not have a Material Adverse Effect. For purposes of this Agreement, any event, occurrence or condition shall have a "Material Adverse Effect" if such event, occurrence or condition, either individually or together with all other events, occurrences or conditions, (1) has a material adverse effect on the ownership, use, operation or value of the Purchased Assets, taking into account the nature and valuation of the Purchased Assets or (2) materially hinders or impedes the consummation of the transactions contemplated by this Agreement, except to the extent resulting from or arising in connection with (i) this Agreement or the transactions contemplated hereby or the public announcement thereof; (ii) changes, circumstances or effects (A) that affect generally the oil and gas industry, such as fluctuations in the price of oil and gas, or (B) that result from (1) international, national, regional, state or local economic conditions, (2) general developments or conditions in the oil and gas industry, (3) changes in applicable Laws and Regulations or the application or interpretation thereof by any Governmental Authority enacted, promulgated or issued on or after the date hereof or (4) other general economic conditions, facts or circumstances that are not subject to the reasonable control of the Parties; (iii) effects of conditions or events resulting from an outbreak or escalation of hostilities (whether nationally or internationally), or the occurrence of any other calamity or crisis (whether nationally or internationally), including the occurrence of one or more terrorist attacks; or (iv) any action taken at the written request, or with the written approval, of the Buyer; *provided*, *however*, that the changes, circumstances or effects set forth in (2)(ii)(A) and (B) above shall be deemed to have a Material Adverse Effect to the extent such changes, circumstances or effects disproportionately impact the Purchased Assets compared with the oil and gas industry generally or international, national, regional, state or local economic conditions, as applicable.

(d) Title to Purchased Assets. Such Seller owns the Purchased Assets free and clear of all liens, mortgages, security interests, pledges, claims, charges, options or other encumbrances substantially equivalent thereto (collectively, "**Lien**") created by, through or under such Seller, other than Permitted Liens (as defined below). For purposes of this Agreement, the term "Permitted Liens" shall mean all (i) materialman's, mechanic's, repairman's, employee's, contractor's, operator's, tax and other similar liens or charges arising in the ordinary course of business for obligations that are not delinquent and that will be paid and discharged in the ordinary course of business or, if delinquent, that are being contested in good faith by appropriate action of which Buyer is notified in writing before the Closing; (ii) Customary Post-Closing Consents; (iii) easements, rights-of-way, servitudes, permits, surface leases and other rights in respect of surface operations that do not materially interfere with or have an adverse effect on the ownership, use, value or operation of the Purchased Assets; (iv) rights reserved to or vested in any Governmental Authority to control or regulate any of the Purchased Assets in any manner; (v) applicable Laws and Regulations, (vi) terms and conditions of the Rights of Way and Contracts; and (vii) Liens released at or prior to the Closing.

(e) Brokerage. Neither such Seller nor any of its Affiliates has made any agreement or taken any other action which might cause any person or entity to become entitled to a broker's or finder's fee or commission for which Buyer or any of Buyer's Affiliates shall directly or indirectly have any responsibility, liability or expense as a result of the transactions contemplated hereby.

4.2 Representations and Warranties of Sellers. Each Seller, jointly and severally, represents and warrants to Buyer as of the date hereof and as of the Closing Date that:

(a) No Violation of Laws or Agreements. The execution, delivery and performance of this Agreement and the other Seller Transaction Documents by any Seller does not, and the consummation of the transactions contemplated hereby and thereby and the compliance by any Seller with any of the provisions hereof and thereof will not, conflict with, result in any violation of or default (with or without notice or lapse of time or both) under, give rise to a right of termination, cancellation or acceleration of any obligation or to the loss of a material benefit under, or result in the creation of any Lien on any of the Purchased Assets under, any provision of any Right of Way or Contract (except as set forth on Schedule 4.2(b)), except for any such conflicts, violations, defaults, rights, losses or Liens that would not have a Material Adverse Effect.

(b) Approvals and Consents. Except as set forth on Schedule 4.1(c) or **Schedule 4.2(b)**, (i) no notice to, consent, approval, order or authorization of, registration, declaration or filing with, or permit from, any federal, state or local governmental or regulatory entity (or any agency, authority, board, bureau, commission, department, tribal authority or political subdivision thereof) or any court or arbitrator (each, a "Governmental Authority") or any person or entity is required in connection with the execution or performance of this Agreement or the other Seller Transaction Documents by any Seller or the consummation by any Seller of the transactions contemplated hereby and thereby, except for consents or approvals of, or notices to, any Governmental Authority that are customarily obtained or given after closing in connection with the transactions contemplated hereby (collectively, the "Customary Post-Closing Consents"), and (ii) no Purchased Asset is subject to any preferential right to purchase, right of first refusal, right of first offer or similar right which would be binding on Buyer after the consummation of the transactions contemplated hereby.

(c) Proceedings; Orders. Except set forth on **Schedule 4.2(c)**, there are no actions, suits, claims or proceedings (including any arbitration or mediation or similar proceedings) by or before any Governmental Authority (collectively, "Proceedings") pending or, to any Seller's knowledge, threatened against any Seller affecting the Purchased Assets or that would prohibit, restrict or delay in any material respect the consummation of the transactions contemplated hereby. There are currently no outstanding judgments, decrees, injunctions, rulings, orders or awards of any Governmental Authority (collectively, "Orders") against any Seller which relate to or arise out of the ownership, condition, use or operation of the Purchased Assets or that would prohibit, restrict or delay in any material respect the consummation of the transactions contemplated hereby.

(d) Compliance with Laws. Except as set forth on Schedule 4.2(d), no Seller has violated or failed to comply with any federal, state or local constitution, statute, law, ordinance, rule or regulation or any Order (collectively, "Laws and Regulations") applicable to the Purchased Assets, except for any such violations or failures as would not have a Material Adverse Effect. Except as set forth on Schedule 4.2(d), no Seller has received any written notice from any Governmental Authority of any violation of any Laws and Regulations applicable to the Purchased Assets.

(e) Permits. Schedule 1.1(e) sets forth all material Permits. Sellers (i) possess all material Permits required to own, lease, operate or use the Purchased Assets under all Laws and Regulations and (ii) are in material compliance with all terms, provisions and conditions of the Purchased Permits. All Permits are in full force and effect, and there are no Proceedings pending or, to Sellers' knowledge, threatened that seek the revocation, cancellation, suspension or any materially adverse modification, or the imposition of any penalty with respect to, any Permits.

(f) Rights of Way. The Rights of Way listed on Schedule 1.1(b) comprise all of the material Rights of Way necessary to own and operate the Gathering Assets as operated on the date hereof. Sellers have all material Rights of Way necessary to own and operate the Gathering Assets. The Gathering Assets are all located within valid Rights of Way. With respect to each material Right of Way, no Seller is in material breach of or material default under, no Seller has received written notice that it is in material breach or material default under, and no event has occurred which with notice or lapse of time (or both) would constitute a material breach by any Seller of or material default by any Seller under, such Right of Way. All payments due as of the Closing Date under each Right of Way have been paid in full. Sellers have made available to Buyer true, correct and complete copies of all Rights of Way.

(g) Environmental Matters.

(i) Sellers have not received any written notice from any Governmental Authority or any other person or entity that the operation of any Purchased Asset is in violation of any Environmental Laws or that Sellers or any predecessors in title of Sellers are responsible (or potentially responsible) for remedying, stabilizing, neutralizing or cleaning up any pollutants, contaminants or hazardous or toxic waste, substances or materials at, on or beneath any such Purchased Asset, except for any such violations or responsibilities that would not have a Material Adverse Effect. To Sellers' knowledge, no environmental or physical condition of any Purchased Asset violates any Environmental Law, Right of Way, Contract or other agreement, except for any such violations that would not have a Material Adverse Effect.

(ii) There has been no Release of any Hazardous Substance by a from any of the Purchased Assets, or as a result of any operations or activities of the Gathering Assets, that could reasonably be expected to give rise to any remedial obligation, corrective action requirement or other liability of any kind under applicable Environmental Laws, except for any such Releases that would not have a Material Adverse Effect.

(iii) For the purposes of this Agreement:

(A) "Environmental Laws" means any applicable law of any Governmental Authority relating to (i) the protection, preservation or restoration of the environment or the protection of the public health and safety (including, air, surface water, groundwater, drinking water supply, surface land, subsurface land, plant and animal life or any other natural resource) or (ii) the exposure to, or the use, storage, recycling, treatment, generation, transportation, processing, handling, labeling, production, Release or disposal of Hazardous Substances, in each case as in effect at the date hereof.

(B) "Hazardous Substance" means any substance presently listed, defined, designated or classified as hazardous, toxic, radioactive or dangerous, or otherwise regulated, under any Environmental Law. Hazardous Substance includes any substance to which exposure is regulated by any Governmental Authority or any Environmental Law, including any toxic waste, pollutant, contaminant, hazardous substance, toxic substance, hazardous waste, special waste or petroleum or any derivative or byproduct thereof, radon, radioactive material, asbestos or asbestos containing material, urea formaldehyde, foam insulation or polychlorinated biphenyls.

(C) "Release" means any spill, effluent, emission, leaking, pumping, pouring, emptying, escaping, dumping, injection, deposit, disposal, discharge, dispersal, leaching, abandoning, adding or migration of any Hazardous Substance into the indoor or outdoor environment, or into or out of any property or facility.

(h) Transactions with Affiliates. There are no agreements, loans, leases, royalty agreements or other continuing transactions between any Seller and any officer, member, partner, manager, director or stockholder of any Seller or any of their Affiliates with respect to the Purchased Assets or the Gathering Assets which shall be binding on Buyer, the Purchased Assets or the Gathering Assets following the Closing (collectively, "Affiliate Agreements").

(i) Intellectual Property. There is no intellectual property-related proceeding pending or threatened by any third party before any court or tribunal (including, the United States Patent and Trademark Office or equivalent authority anywhere in the world) relating to the Purchased Assets or the Gathering Assets, nor has any written claim or demand been made by any third party that alleges any infringement, misappropriation or violation of any intellectual property of any third party, or unfair competition or trade practices relating to the Purchased Assets or the Gathering Assets.

(j) Taxes.

(i) Each Seller has filed all material tax returns with regard to the Purchased Assets that it was required to file. All such tax returns as so filed disclose all taxes required to be paid for the periods covered thereby. All material taxes due and owing by any Seller with regard to the Purchased Assets (whether or not shown on any tax return) have been paid. No Seller is currently is the beneficiary of any extension of time within which to file any tax return with regard to the Purchased Assets. There are no Liens for taxes (other than taxes not yet due and payable) upon any of the Purchased Assets. Each Seller has withheld and paid all taxes required to have been withheld and paid in connection with amounts paid or owing to any employee, independent contractor, creditor, shareholder or other third party with regard to the Purchased Assets, and all Forms W-2 and 1099 required with respect thereto have been properly completed and timely filed.

(ii) There is no material dispute or claim concerning any tax liability of any Seller with regard to the Purchased Assets either (A) claimed or raised by any

Governmental Authority in writing or (B) as to which any Seller has knowledge based upon personal contact with any agent of such Governmental Authority.

(k) Integrity Management; Maintenance. The Purchased Assets have been operated in the ordinary course and all routine maintenance and integrity management procedures that would be completed by a reasonably prudent operator have been performed or are in process.

(l) Contracts. The Contracts listed on Schedule 1.1(c) comprise all of the material Contracts. With respect to each Contract, no Seller is in breach of or default under, no Seller has received written notice that it is in breach or default under, and no event has occurred which with notice or lapse of time (or both) would constitute a breach by any Seller of or default by any Seller under, such Contract, except for such breaches or defaults as would not have a Material Adverse Effect. Sellers have made available to Buyer true, correct and complete copies of all Contracts. To Sellers' knowledge, no counterparty is in material default under, no Seller has delivered written notice that a counterparty is in breach or default under, and no event has occurred which with notice or lapse of time (or both) would constitute a material breach by any counterparty of or material default by any counterparty under, such Contract

4.3 Representations and Warranties of Buyer. Buyer represents and warrants to Sellers as of the date hereof and as of the Closing Date that:

(a) Organization and Good Standing. Buyer is a limited liability company validly existing and in good standing under the laws of the State of Delaware. Buyer has all requisite limited liability company power and authority to own, lease and operate its assets and properties and conduct its business as and where such business is currently being conducted. Buyer is qualified or registered to do business and is in good standing as a foreign entity in the State of Texas.

(b) Authorization and Enforceability. Buyer has the requisite limited liability company power and authority to execute, deliver and perform its obligations under this Agreement and the other Buyer Transaction Documents and to consummate the transactions contemplated hereby and thereby. The execution, delivery and performance by Buyer of this Agreement and the other Buyer Transaction Documents have been duly and validly authorized by all necessary limited liability company action on the part of Buyer. This Agreement has been, and the other Buyer Transaction Documents will be, duly and validly executed and delivered by Buyer. This Agreement is, and the other Buyer Transaction Documents will be, the legal, valid and binding obligations of Buyer, enforceable against Buyer in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, moratorium, reorganization, fraudulent conveyance and similar laws affecting creditors' rights generally and except to the extent that general equitable principles may affect the availability of certain remedies.

(c) No Violation of Laws or Agreements. The execution, delivery and performance of this Agreement and the other Buyer Transaction Documents by Buyer do not, and the consummation of the transactions contemplated hereby and thereby and the compliance by Buyer with any of the provisions hereof and thereof will not, conflict with, result in any violation of or default (with or without notice or lapse of time or both) under, give rise to a right of termination, cancellation or acceleration of any obligation or to the loss of a material benefit under, or result in the creation of any Lien on any of the assets or properties of Buyer under, any provision of (i) the organizational documents of Buyer, (ii) any loan or credit agreement, note, bond, mortgage, indenture, contract, lease, permit, concession, franchise, license or other agreement or instrument applicable to Buyer or (iii) any Laws and Regulations applicable to Buyer or any of its assets or properties, except, in the cases of clauses (ii) and (iii), for any such conflicts, violations, defaults, rights, losses or Liens that would not materially hinder or impede the consummation of the transactions contemplated by this Agreement.

(d) Approvals and Consents. No notice to, consent, approval, order or authorization of, registration, declaration or filing with, or permit from, any governmental authority or other person or entity is required by or with respect to Buyer in connection with the execution and performance of this Agreement or the other Buyer Transaction Documents by Buyer or the consummation by Buyer of the transactions contemplated hereby and thereby, except for the Customary Post-Closing Consents.

(e) Proceedings; Orders. There are no Proceedings pending or, to Buyer's knowledge, threatened against Buyer that would prohibit, restrict or delay in any material respect the consummation of the transactions contemplated hereby. There are currently no outstanding Orders against Buyer that would prohibit, restrict or delay in any material respect the consummation of the transactions contemplated hereby.

(f) Brokerage. Neither Buyer nor any of its Affiliates has made any agreement or taken any other action which might cause any person or entity to become entitled to a broker's or finder's fee or commission for which any Sellers or any Affiliate of any Seller shall directly or indirectly have any responsibility, liability or expense as a result of the transactions contemplated hereby.

(g) Funding. Buyer has available adequate funds or the means to obtain adequate funds in the aggregate amount sufficient to pay (i) the Purchase Price and (ii) all expenses incurred by Buyer in connection with this Agreement and the transactions contemplated hereby.

(h) Due Diligence Investigation. Buyer has the expertise, knowledge and sophistication in financial and business matters generally and with respect to the oil and gas industry that make it capable of evaluating, and it has evaluated, the merits and economic risks of its investment in the Purchased Assets. Buyer has had the opportunity to examine all aspects of the Purchased Assets Buyer has deemed relevant and has had access to all information requested by Buyer with respect to the Purchased Assets and the Assumed Liabilities in order to make an evaluation thereof. In making its decision to enter into this Agreement and to consummate the transactions contemplated hereby, Buyer has relied and will rely solely on the provisions of this Agreement and its own independent investigation and evaluation of the Purchased Assets and the value thereof.

4.4 Disclaimers and Notifications. The Parties make the following disclaimers and notifications:

(a) No Other Seller Representations. EXCEPT AS EXPRESSLY SET FORTH IN SECTIONS 4.1 AND 4.2, THE CONVEYANCE, THE DEEDS , THE PARTIAL ASSIGNMENTS OR ANY OTHER AGREEMENTS OR INSTRUMENTS DELIVERED AT THE CLOSING PURSUANT TO SECTION 3.2, SELLERS AND THEIR REPRESENTATIVES AND ADVISORS HAVE NOT MADE AND MAKE NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AT LAW OR IN EQUITY, IN RESPECT OF ANY OF THE PURCHASED ASSETS OR ANY LIABILITIES OR OPERATIONS RELATED THERETO (INCLUDING THE ASSUMED LIABILITIES), INCLUDING WITH RESPECT TO MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, AND ANY SUCH OTHER REPRESENTATIONS OR WARRANTIES ARE HEREBY EXPRESSLY DISCLAIMED, IN EACH CASE INCLUDING, BUT NOT LIMITED TO, ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED AS TO (I) TITLE TO ANY OF THE PURCHASED ASSETS, (II) THE CONTENTS, CHARACTER OR NATURE OF ANY DESCRIPTIVE MEMORANDUM, OR ANY REPORT OF ANY PETROLEUM ENGINEERING CONSULTANT, OR ANY GEOLOGICAL OR SEISMIC DATA OR INTERPRETATION, RELATING TO THE PURCHASED ASSETS, (III) THE CURRENT VOLUME, NATURE, QUALITY, CLASSIFICATION OR VALUE OF THE HYDROCARBON RESERVES DEDICATED TO THE GATHERING ASSETS PURSUANT TO ANY GAS PURCHASE CONTRACTS, (IV) ANY ESTIMATES OF THE VALUE OF THE PURCHASED ASSETS OR FUTURE REVENUES GENERATED BY THE PURCHASED ASSETS, (V) THE MAINTENANCE, REPAIR, CONDITION, QUALITY, SUITABILITY, DESIGN OR MARKETABILITY OF THE PURCHASED ASSETS, (VI) INFRINGEMENT OF ANY INTELLECTUAL PROPERTY RIGHT OR (VII) ANY OTHER RECORD, FILES OR MATERIALS OR INFORMATION THAT MAY HAVE BEEN MADE AVAILABLE OR COMMUNICATED TO BUYER OR ITS AFFILIATES, OR ITS OR THEIR EMPLOYEES, AGENTS, CONSULTANTS, REPRESENTATIVES OR ADVISORS IN CONNECTION WITH THE TRANSACTIONS CONTEMPLATED HEREBY. SELLERS FURTHER DISCLAIM ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, OF CONFORMITY TO MODELS OR SAMPLES OF MATERIALS OF ANY EQUIPMENT. BUYER HEREBY ACKNOWLEDGES AND AGREES THAT, EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH IN SECTIONS 4.1 AND 4.2, THE CONVEYANCE, THE DEEDS, THE PARTIAL ASSIGNMENTS OR ANY OTHER AGREEMENTS OR INSTRUMENTS DELIVERED AT THE CLOSING PURSUANT TO SECTION 3.2, BUYER IS PURCHASING THE PURCHASED ASSETS ON AN “AS-IS, WHERE-IS” BASIS WITH ALL FAULTS AND DEFECTS AND BUYER HAS MADE OR CAUSED TO BE MADE SUCH INSPECTIONS AS BUYER DEEMS APPROPRIATE.

(b) No Other Buyer Representations. EXCEPT AS EXPRESSLY SET FORTH IN SECTION 4.3, THE CONVEYANCE, THE DEEDS, THE PARTIAL ASSIGNMENTS OR ANY OTHER AGREEMENTS OR INSTRUMENTS DELIVERED AT THE CLOSING PURSUANT TO SECTION 3.3, THE BUYER AND THEIR REPRESENTATIVES AND ADVISORS HAVE NOT MADE AND MAKE NO REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AT LAW OR IN EQUITY.

(c) Disclaimer with Respect to NORM, etc. BUYER ACKNOWLEDGES AND AGREES THAT THE PURCHASED ASSETS HAVE BEEN UTILIZED BY SELLERS FOR THE PURPOSE OF GATHERING AND TRANSPORTING HYDROCARBONS AND

THAT MATERIALS ASSOCIATED THEREWITH MAY HAVE BEEN STORED, KEPT OR DISPOSED OF ON OR IN THE PURCHASED ASSETS. BUYER ACKNOWLEDGES THAT EQUIPMENT, IMPROVEMENTS, ABANDONED AND PIPING, GATHERING LINES AND OTHER HYDROCARBON PROCESSING FACILITIES AND APPURTENANCES MAY BE LOCATED THEREON. BUYER ACKNOWLEDGES THAT THERE MAY HAVE BEEN SPILLS OF HYDROCARBONS OR OTHER MATERIALS IN THE PAST ON OR IN THE ASSETS. IN ADDITION, SOME ASSETS MAY CONTAIN ASBESTOS AND NATURALLY OCCURRING RADIOACTIVE MATERIAL ("NORM"). IN THIS REGARD, BUYER EXPRESSLY ACKNOWLEDGES AND AGREES THAT NORM MAY AFFIX OR ATTACH ITSELF TO THE INSIDE OF THE FACILITIES AND EQUIPMENT AS SCALE, OR IN OTHER FORMS, AND THAT THE FACILITIES AND EQUIPMENT MAY CONTAIN NORM AND THAT NORM-CONTAINING MATERIAL MAY BE BURIED AND OTHERWISE DISPOSED OF ON THE ASSETS. BUYER ALSO EXPRESSLY UNDERSTANDS THAT SPECIAL PROCEDURES MAY BE REQUIRED FOR THE REMOVAL AND DISPOSAL OF ASBESTOS AND NORM FROM THE ASSETS AND THAT BUYER ASSUMES ALL LIABILITY AND EXPENSE FOR SUCH ASSESSMENT, REMOVAL AND DISPOSAL OF ANY SUCH MATERIALS AND ASSOCIATED ACTIVITIES.

(d) Disclaimer with Respect to Data. All data, evaluations, reports and other information heretofore furnished to Buyer by Sellers concerning any or all of the Purchased Assets, and the operation thereof, have been and shall be furnished solely for Buyer's convenience and have not constituted and shall not constitute a representation or warranty of any kind by Sellers. Sellers do not warrant or represent the accuracy or completeness of any information, data or materials furnished to Buyer with respect to the transactions contemplated by this Agreement. Buyer acknowledges that Sellers may not have the requisite information with which to accurately determine the exact nature or condition of the Purchased Assets. Buyer is purchasing the Purchased Assets solely in reliance on the representations and covenants of Sellers in the Transaction Documents and on its own evaluation and investigation of the Purchased Assets.

ARTICLE 5
COVENANTS

5.1 General. Each of Buyer and Sellers shall use its reasonable efforts in good faith to take all actions and to do all things necessary or advisable in order to consummate and make effective the purchase and sale of the Purchased Assets contemplated by this Agreement, including satisfaction of the closing conditions set forth in Sections 6.1 and 6.2 below.

5.2 Access. From and after the date of this Agreement and until the Closing Date, Sellers shall permit Buyer's officers, employees, agents and advisors, at Buyer's sole risk and expense, to (i) have reasonable access to the Purchased Assets (so long as such access occurs during normal business hours or at mutually agreeable times and does not unreasonably interfere with the operation of the Purchased Assets) to observe the condition, use and operation of the Purchased Assets and to facilitate the transactions contemplated by this Agreement and (ii) otherwise perform due diligence activities, including title searches. Buyer agrees to maintain the confidentiality of all information acquired by Buyer pursuant to this Section 5.2 in accordance with the terms of the Confidentiality Agreement (as defined in Section 5.11 below). Buyer agrees to indemnify, defend and hold harmless the Seller Indemnified Parties from and against any and all Damages (as defined in Section 7.2 below) arising out of or relating to access to the Purchased Assets prior to the Closing by Buyer, even if caused in whole or in part by the negligence (whether sole, joint or concurrent), strict liability or other legal fault of any Seller Indemnified Parties (but excluding gross negligence or willful misconduct on the part of any Seller Indemnified Parties).

5.3 Conduct of Business. From and after the date of this Agreement and until the Closing Date, each Seller agrees that:

(a) It shall conduct its business and operations in the ordinary course of business and in substantially the same manner as such business and operations have been conducted prior to the date of this Agreement;

(b) It shall maintain, operate and administer the Purchased Assets in the ordinary course of business and consistent with past practice and in compliance with all applicable Laws and Regulations; and

(c) It shall not:

(i) sell, assign, transfer or lease or agree to sell, assign, transfer or lease or otherwise dispose of any of the Purchased Assets, except for (A) sales and dispositions of oil and gas in the ordinary course of business (including all condensate and natural gas liquids tank fill and pipeline fill) and (B) sales and dispositions of equipment and materials that are surplus, obsolete or replaced, *provided*, *however*, that such sales and dispositions of equipment and materials that are surplus, obsolete or replaced shall not exceed One Hundred Thousand Dollars ($100,000);

(ii) subject any of the Purchased Assets to any Lien (other than a Permitted Lien);

(iii) amend any tax returns or change any tax elections with respect to the Purchased Assets to the extent such could affect Buyer after the Closing Date;

(iv) modify, amend or terminate any Right of Way or Contract;

(v) enter into any new Contract that (i) may not be cancelled, without undue burden or cost, within ninety (90) days or (ii) the total obligation or benefit or which is, or could be reasonably contemplated to be, in excess of Fifty Thousand Dollars ($50,000);

(vi) abandon or release any Right of Way or Permit;

(vii) incur any capital costs or expenses in respect of the Purchased Assets, other than those set forth on Schedule 5.3, in excess of Two Hundred Fifty Thousand Dollars ($250,000) per month;

(viii) enter into any Affiliate Agreement; or

(ix) waive, compromise or settle any material rights under any Right of Way or Contract.

Buyer's approval of any action restricted by this Section 5.3 shall not be unreasonably withheld or delayed and shall be considered granted 10 days (unless a shorter time is reasonably required by the circumstances and such shorter time is specified in the Seller Representative's notice) after the Seller Representative's notice to Buyer requesting such consent unless Buyer notifies the Seller Representative to the contrary during that period. Notwithstanding the foregoing provisions of this Section 5.3, in the event of an emergency, Sellers may take such action as reasonably necessary to prevent damage to people or property and shall notify Buyer of such action promptly thereafter.

5.4 Consents. From and after the date of this Agreement and until the Closing Date, Sellers shall use commercially reasonable efforts to obtain the written consent from any person or entity with respect to any Right of Way or Contract that is required to permit the sale, transfer and assignment of such Right of Way or Contract pursuant to the terms and conditions thereof (the "Consents"). All such Consents are set forth on Schedule 5.4. Notwithstanding anything in this Agreement to the contrary, neither Party shall be obligated to make any payments to any holder of any Consent or incur any other material burden in order to comply with the requirements set forth in this Section 5.4 and the failure to obtain any such Consent shall not be deemed a breach of any covenant of any Party hereunder.

5.5 Risk of Loss of Purchased Assets. The risk of damage or loss to the Purchased Assets shall remain with Sellers until the Effective Time.

5.6 Transfer Taxes. Buyer shall pay all sales, use, gross receipts, transfer, real property transfer, documentary stamp, recording and other similar taxes arising from and with respect to the purchase and sale of the Purchased Assets.

5.7 Recording. Buyer shall be solely responsible for recording of the Partial Assignments and any other documents related to the conveyance of the Purchased Assets and shall promptly furnish Sellers with either the recorded originals or with the recording information thereof. All recording and filing shall be at the sole cost and expense of Buyer.

5.8 Allocation of Taxes.

(a) All ad valorem real property taxes, personal property taxes, fees or assessments for the calendar year 2014 due with respect to the Purchased Assets or payable by Sellers pursuant to the terms of any Rights of Way or Contracts shall be prorated between Sellers, on the one hand, and Buyer, on the other hand, as of the Closing Date on a calendar year basis, using the calendar year 2013 tax rates and assessments by the appropriate Governmental Authority; *provided, however,* that, if the taxes for 2014 are thereafter determined to be more or less than the taxes for 2013 (after any appeal of the assessed valuation thereof is concluded), Buyer and Sellers promptly shall adjust the proration of such taxes based on actual taxes paid with respect to 2014, and Sellers or Buyer, as the case may be, shall pay to the other any amount required as a result of such adjustment. The portion of such taxes allocable to the portion of calendar year 2014 ending on the Effective Time shall be deemed to be (A) the amount of such taxes for the entire period *multiplied by* (B) a fraction, the numerator of which is the number of calendar days in the portion of calendar year 2014 ending on the Effective Time and the denominator of which is 365. All special taxes or assessments prior to the end of 2014 shall be prorated as set forth above. If any Party shall pay such taxes for which it is entitled to be reimbursed because of such proration, the other Party responsible therefor shall promptly reimburse the party so paying upon notice of the amount paid by such Party.

(b) Sellers shall be responsible for any sales, use, excise, environmental, custom or other like tax, duty, fee or assessment or charge imposed by a Governmental Authority that is associated with the Purchased Assets prior to the Effective Time.

(c) Sellers shall be entitled to any refunds or credits of taxes paid with respect to the Purchased Assets to the extent attributable to the period prior to the Effective Time. Buyer shall be entitled to any refunds or credits of taxes paid with respect to the Purchased Assets to the extent attributable to the period after the Effective Time.

(d) Sellers shall be responsible for the preparation and filing of any tax returns, consistent with past practice, and the payment of any tax required to be paid in connection therewith related to Sellers that are required to be filed for taxable periods ending prior to or on the Closing Date. Buyer shall be responsible for the preparation and filing of all tax returns and the payment of any tax required to be paid in connection therewith related to Buyer that are required to be filed for taxable periods ending after the Closing Date.

(e) Each Party shall be responsible for its own income taxes, if any, which may result from the transactions contemplated by this Agreement.

(f) No Seller shall take or omit to take any action outside of the ordinary course of business or in a manner inconsistent with past practice if such action or omission could have the effect of increasing the tax liability relating to any of the Purchased Assets, Buyer or any of Buyer's Affiliates, unless required by applicable Laws and Regulations.

5.9 Transaction Expenses. Except as expressly provided otherwise herein, each Party shall pay its own expenses and the fees and expenses of its counsel, accountants, consultants and other experts and representatives incurred in connection with the execution and delivery of this Agreement and the other Transaction Documents and the consummation of the transactions contemplated hereby and thereby.

5.10 Maintenance of Books and Records. At the Closing, Sellers shall deliver to Buyer the Records. Buyer and Sellers shall cooperate fully with one another after the Closing so that (subject to any limitations that are reasonably required to preserve any applicable attorney-client or other legal privilege) each Party has access to the business records, contracts and other information existing at the Closing Date and relating in any manner to the Purchased Assets (whether in the possession of Sellers or Buyer). No files, books or records existing at the Closing Date and relating in any manner to the Purchased Assets shall be destroyed by any Party for a period of two years after the Closing Date (or such longer period as is required by applicable Laws and Regulations). The access to files, books and records contemplated by this Section 5.10 shall be during normal business hours and upon not less than two days prior written request, shall be subject to such reasonable limitations as the Party having custody or control thereof may impose to preserve the confidentiality of information contained therein, and shall not extend to material subject to a claim of privilege unless expressly waived by the Party entitled to claim the same.

5.11 Confidentiality. The respective obligations of the Parties with regard to the use and disclosure of information provided to one Party by the other are set forth in the Confidentiality Agreement dated September 5, 2013 (the "Confidentiality Agreement"), between PVOG and American Midstream Partners, L.P. (" AMID"), an Affiliate of Buyer. Notwithstanding anything in the Confidentiality Agreement or this Agreement to the contrary, Sellers and Buyer shall consult with each other with regard to all publicity and other public releases concerning this Agreement and the transactions contemplated hereby; *provided, however,* that nothing contained in this Agreement or the Confidentiality Agreement shall restrict any Party or any Affiliate of any Party from making any disclosure required by applicable Laws and Regulations or the applicable rules of any stock exchange. Sellers shall use commercially reasonable efforts to (i) assign all confidentiality agreements relating to the sale of the Purchased Assets to Buyer or (ii) if such assignment cannot be made, cause any person or entity which received confidential information about the Purchased Assets to return to Sellers or destroy such confidential information.

5.12 Release of Bonds. Upon the request of Sellers, Buyer shall assist Sellers in a commercially reasonable manner to release or cause the release or cancellation any bonds, letters of credit or guarantees posted by any Seller with Governmental Authorities and relating to the Purchased Assets. All such bonds, letters of credit or guarantees are set forth on Schedule 5.12.

5.13 Names. As soon as reasonably possible after the Closing, but in no event later than 60 days after Closing, Buyer shall remove the names of PVOG, including "Penn Virginia," "Penn Virginia Oil & Gas," "PVOG" and all variations thereof, from all of the Purchased Assets and make the requisite filings with, and provide the requisite notices to, the appropriate Governmental Authorities to place the title or other indicia of ownership, including operation of the Purchased Assets, in a name other than any name of PVOG or any variations thereof.

5.14 Revised Schedules. On one or more occasions not later than three business days prior to the Closing Date, the Seller Representative may prepare and deliver to Buyer revised Schedules to this Agreement relating to the representations and warranties set forth in Section 4.1 or Section 4.2 above, which revised Schedules may include new Schedules to the extent that any of the representations and warranties set forth in Section 4.1 or Section 4.2 above do not provide for Schedules, reflecting events or changes in circumstances occurring after the date of this Agreement. Prior to the Closing, any such revised or supplemental Schedules shall be for informational purposes only and of no force or effect in connection with determining whether the conditions to the Closing set forth in Section 6.2 below have occurred or been satisfied. In the event that the Closing occurs, then for the sole purposes of the indemnification provisions set forth in Article 7 below, any representations and warranties of Sellers as set forth in Section 4.1 or Section 4.2 above shall be subject to, and modified by, any such timely delivered revisions or supplements to the Schedules to this Agreement.

5.15 Government Reviews. As promptly as practicable after the date of this

Agreement (but in any event within three business days of this date of this Agreement), Sellers and Buyer shall in a timely manner (a) make all required filings, if any, with and prepare applications to and conduct negotiations with each Governmental Authority as to which such filings, applications or negotiations are necessary or appropriate in connection with the consummation of the transactions contemplated hereby, specifically including, but not limited to, the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act"), (b) provide such information as each may reasonably request to make such filings, prepare such applications and conduct such negotiations and (c) request early termination or waiver of any applicable waiting period under the HSR Act. To the extent reasonably practicable, Sellers and Buyer shall each have the right to review in advance all information relating to such Party that is disclosed for any filing. Each Party shall cooperate with and use all commercially reasonable efforts to assist the other with respect to such filings, applications and negotiations and shall promptly furnish each other with copies of any written communications delivered to such Party from any Governmental Authority. The applicable filing fee in connection with the filings to be made under the HSR Act shall be borne 50% by Buyer and 50% by Sellers.

5.16 Further Assurances. At or after the Closing, any Party, at the request of any other Party and without additional consideration, shall execute and deliver to the requesting Party all such further assignments, deeds, agreements, contracts, instruments and other documents as the requesting Party may reasonably request in order to perform, accomplish, perfect or record, if reasonably necessary, the sale, assignment, transfer and delivery to Buyer of the Purchased Assets as contemplated by this Agreement, to obtain the Customary Post-Closing Consents and to otherwise carry out the intention of this Agreement.

5.17 Financial Information. Sellers hereby agree to provide to Buyer access to such records, materials and documents in Sellers possession as may be reasonably requested from time to time by Buyer and its auditors in connection with the completion and delivery of such information as is required by the Securities and Exchange Commission to be included in any periodic report to be filed by AMID under the Securities Exchange Act of 1934, as amended, with respect to the Gathering Assets.

5.18 Rights-of-Way. Sellers shall use all commercially reasonable efforts to (a) procure and record valid rights-of-way across the leases set forth on Schedule 5.18 (the "Necessary ROWs") and (b) record (to the extent not already recorded) all of the Rights of Way set forth on Schedule 1.1(b).

5.19 Replacement of Drip Tanks. Buyer acknowledges and agrees that the drip tanks currently used to operate the Gathering Assets are not Purchased Assets and, consequently, Buyer will need to procure and install new drip tanks for the operation of the Gathering Assets following the Closing. Buyer shall procure and install such new drip tanks within 90 days following the Closing Date. During such 90-day period, Sellers shall allow Buyer to continue to use Sellers' existing drip tanks in connection with the operation of the Gathering Assets. Buyer agrees to indemnify, defend and hold harmless the Seller Indemnified Parties from and against any and all Damages arising out of or relating to Buyer's use of Sellers' existing drip tanks, even if caused in whole or in part by the negligence (whether sole, joint or concurrent), strict liability or other legal fault of any Seller Indemnified Parties (but excluding gross negligence or willful misconduct on the part of any Seller Indemnified Parties).

ARTICLE 6
CONDITIONS TO CLOSING

6.1 Conditions to Obligations of Sellers. The obligations of Sellers to consummate the transactions contemplated by this Agreement are subject, at the option of Sellers, to the following conditions:

(a) Representations. The representations and warranties of Buyer herein contained shall be made again at the Closing and shall be true and correct in all material respects on the Closing Date.

(b) Performance. Buyer shall have performed and complied with in all material respects all of its obligations, covenants and agreements contained in this Agreement to be performed or complied with by it at or prior to the Closing.

(c) Regulatory Compliance. Buyer and Sellers shall each be in compliance with all material regulatory requirements of all applicable Governmental Authorities necessary to consummate the transactions contemplated herein (all of which shall be in full force and effect as of the Closing). Any waiting period applicable to the consummation of the transactions contemplated by this Agreement under the HSR Act shall have expired or terminated (by early termination or otherwise).

(d) Pending Matters. No Order or Proceeding shall be outstanding or pending that restrains, enjoins or otherwise prohibits, or could reasonably be expected to restrain, enjoin or otherwise prohibit, the consummation of the transactions contemplated by this Agreement.

(e) No Bankruptcy. There shall be no bankruptcy, reorganization, receivership or arrangement proceedings pending against Buyer or any Affiliate of Buyer.

(f) Closing Deliveries. Sellers shall have received all of the deliveries required by Section 3.3 above.

The Seller Representative may waive any condition specified in this Section 6.1 if it executes a writing so stating at or prior to the Closing.

6.2 Conditions to Obligations of Buyer. The obligations of Buyer to consummate the transactions contemplated by this Agreement are subject, at the option of Buyer, to the following conditions:

(a) Representations. The representations and warranties of Sellers herein contained shall be made again at the Closing and shall be true and correct in all material respects on the Closing Date.

(b) Performance. Sellers shall have performed and complied with in all material respects all of their obligations, covenants and agreements contained in this Agreement to be performed or complied with by them at or prior to the Closing.

(c) Regulatory Compliance. Buyer and Sellers shall each be in compliance with all material regulatory requirements of all applicable Governmental Authorities necessary to consummate the transactions contemplated herein (all of which shall be in full force and effect as of the Closing). Any waiting period applicable to the consummation of the transactions contemplated by this Agreement under the HSR Act shall have expired or terminated (by early termination or otherwise).

(d) Pending Matters. No Order or Proceeding shall be outstanding or pending that restrains, enjoins or otherwise prohibits, or could reasonably be expected to restrain, enjoin or otherwise prohibit, the consummation of the transactions contemplated by this Agreement.

(e) No Bankruptcy. There shall be no bankruptcy, reorganization, receivership or arrangement proceedings pending against any Seller or any Affiliate of any Seller.

(f) Closing Deliveries. Buyer shall have received all of the deliveries required by Section 3.2 above.

(g) Consents. Sellers shall have received all Consents and delivered copies of all such Consents to Buyer.

(h) Rights-of-Way. Sellers shall have received all Necessary ROWs and shall have recorded all of the Rights of Ways set forth on Schedule 1.1(b).

(i) Casualty Loss. Notwithstanding Section 5.5, in the event of damage or loss to the Purchased Assets valued at over Ten Million Dollars ($10,000,000), Sellers shall have fully remedied the damage or loss.

Buyer may waive any condition specified in this Section 6.2 if it executes a writing so stating at or prior to the Closing.

ARTICLE 7
INDEMNIFICATION

7.1 Survival of Representations, Warranties and Covenants. The representations, warranties and covenants of the Parties in this Agreement or any certificate delivered pursuant to this Agreement shall survive and continue in full force and effect as follows (each applicable period, the "Survival Period"):

(a) All of the representations, warranties and covenants of each Seller contained in Sections 4.1, 4.2 (other than the Fundamental Representations), 5.3 and 5.19 above shall survive the Closing and continue in full force and effect for a period of twelve months after the Closing;

(b) All of the representations and warranties of each Seller set forth in Sections 4.1(a), 4.1(b), 4.1(c)(i), 4.1(d) and 4.1(e) above (collectively, the "Fundamental Representations") shall continue in full force and effect indefinitely;

(c) All of the representations and warranties of Buyer set forth in Section 4.3

above shall continue in full force and effect for a period of twelve months after the Closing; and

(d) All of the covenants set forth herein (other than those set forth in Section 5.3 above and Section 5.19 above with respect to Sellers only and the indemnification provisions of this Article 7) shall continue in full force and effect for a period of two years. Notwithstanding the foregoing the indemnification provisions of this Article 7 shall continue in full force and effect indefinitely.

After the expiration of the applicable Survival Period for a particular representation, warranty or covenant, such representation, warranty or covenant shall automatically expire and terminate. Any claim for indemnification with respect to any breach of any representation, warranty or covenant which is not asserted within the applicable Survival Period by a written notice given as herein provided that identifies the breach underlying such claim may not be pursued and shall be thereafter forever barred.

7.2 Indemnification By Sellers. In the event that the Closing occurs, then each Seller hereby agrees to indemnify, defend and hold Buyer and its Affiliates, each of its and their respective shareholders, members, partners, directors, officers, employees and agents and each of their respective successors and permitted assigns (collectively, the "Buyer Indemnified Parties") harmless from and against any and all liabilities, taxes, Liens, injunctions, awards, judgments, orders, obligations, damages, losses, fines, penalties, amounts paid in settlement, and all costs, fees and expenses (including court costs and reasonable legal and other professional fees and expenses actually incurred in investigating, defending and preparing for any claim, demand, charge, suit, litigation, judicial or administrative proceeding, action, suit, hearing, investigation or complaint) (collectively, "Damages") directly or indirectly arising out of, resulting from or in connection with any of the following:

(a) the breach of or inaccuracy in any representation or warranty made by such Seller in this Agreement or any certificate delivered pursuant to this Agreement; and

(b) the breach of or default in the performance by such Seller of any covenant, agreement or obligation in this Agreement.

The indemnification obligations of Sellers pursuant to this Section 7.2 shall be (A) several, and not joint, with respect to breach of the representations and warranties set forth in Section 4.1 above or any covenant, agreement or obligation in this Agreement and (B) joint and several with respect to breach of the representations and warranties set forth in Section 4.2 above.

7.3 Indemnification By Buyer. In the event that the Closing occurs, Buyer agrees to indemnify, defend and hold each Seller and its Affiliates, each of its and their respective shareholders, members, partners, directors, officers, employees and agents and each of their respective successors and permitted assigns (collectively, the "Seller Indemnified Parties") harmless from and against any and all Damages directly or indirectly arising out of, resulting from or in connection with any of the following:

(a) the breach of or inaccuracy in any representation or warranty made by Buyer in this Agreement or any certificate delivered pursuant to this Agreement;

(b) the breach of or default in performance by Buyer of any covenant, agreement or obligation in this Agreement; and

(c) the Assumed Liabilities.

7.4 Indemnification Procedures. All claims for indemnification under this Agreement related to Third Party Claims shall be asserted and resolved pursuant to this Section 7.4.

(a) Promptly after the receipt by any Person seeking indemnification hereunder (an " Indemnified Party") of a notice of any Proceeding by any third party that may be subject to indemnification hereunder (a " Third Party Claim"), such Indemnified Party shall give written notice of such Third Party Claim to the indemnifying Party (the "Indemnifying Party") stating the nature and basis of the Third Party Claim and the amount thereof, to the extent known, along with copies of the relevant documents evidencing the Third Party Claim and the basis for indemnification sought. Failure of the Indemnified Party to give such notice shall not relieve the Indemnifying Party from liability on account of this indemnification, except if and to the extent that the Indemnifying Party is actually prejudiced thereby.

(b) The Indemnifying Party, at its own expense, shall have the right, exercisable within 30 days of receipt of notice of the Third Party Claim, to assume the defense of the Indemnified Party against the Third Party Claim so long as (i) the Indemnifying Party proceeds in good faith and in a timely manner and (ii) such Third Party Claim involves (and continues to involve) solely monetary damages.

(c) So long as the Indemnifying Party has assumed the defense of the Third Party Claim in accordance with Section 7.4(b) above, (i) the Indemnified Party may retain separate co-counsel at its sole cost and expense and participate in the defense of the Third Party Claim, it being understood that the Indemnifying Party shall pay all costs and expenses of counsel for the Indemnified Party (A) for all periods prior to such time as the Indemnifying Party has notified the Indemnified Party that it has assumed the defense of such Third Party Claim and (B) if there is a conflict of interest between the Indemnifying Party and the Indemnified Party, (ii) the Indemnified Party shall not file any papers or consent to the entry of any judgment or enter into any settlement with respect to the Third Party Claim without the prior written consent of the Indemnifying Party (which consent shall not be unreasonably withheld or delayed), and (iii) the Indemnifying Party shall not consent to the entry of any judgment or enter into any settlement with respect to the Third Party Claim without the prior written consent of the Indemnified Party (which consent shall not be unreasonably withheld or delayed).

(d) The Parties shall use commercially reasonable efforts to minimize Damages from Third Party Claims and shall act in good faith and in a timely manner in responding to, defending against, settling or otherwise dealing with Third Party Claims. The Parties shall also cooperate in any such defense and give each other reasonable access to all information relevant thereto. Whether or not the Indemnifying Party shall have assumed the defense of a Third Party Claim, the Indemnifying Party shall not be obligated to indemnify the Indemnified Party hereunder for any settlement entered into without the Indemnifying Party's prior written consent, which consent shall not unreasonably withheld or delayed. Notwithstanding the foregoing, the Indemnified Party shall have the sole and exclusive right to settle any Third Party Claim, on such terms and conditions as it deems reasonably appropriate, to the extent such claim involves equitable or other non-monetary relief.

7.5 Other Limitations on Indemnification.

(a) No Party shall have any liability pursuant to Section 7.2(a) or Section 7.3(a) above with respect to any breach of any representation or warranty (other than any Fundamental Representation) unless and until the aggregate amount of all of the Damages to the Buyer Indemnified Parties exceeds $2,000,000 (the "Indemnification Threshold"), in which case the Buyer Indemnified Parties shall be entitled to indemnification only to the extent of the excess over the Indemnification Threshold. There shall be no threshold or deductible with respect to (i) Sellers' obligations to Buyer pursuant to Section 7.2(a) above with respect to any breach of any Fundamental Representation or pursuant to Section 7.2(b) above or (ii) Buyer's obligations to Sellers pursuant to Section 7.3(b) or Section 7.3(c).

(b) The aggregate liability of any Party pursuant to this Article 7 shall in no event exceed, individually or in the aggregate, $15,000,000; *provided, however,* that subject to Section 7.5(c) below, (a) Buyer's liability pursuant to Section 7.3(b) above with respect to any covenant (including Buyer's liability to fund the Purchase Price at the Closing) and Section 7.3(c) and (b) Seller's liability pursuant to Section 7.2(a) with respect to any Fundamental Representation and Section 7.2(b) with respect to any covenant, shall, in each case, be without limit.

(c) Under no circumstances shall any Party be liable to any other Party for any indirect, contingent, consequential, unforeseen, exemplary or punitive, special Damages of any nature (including lost profits); *provided, however,* that any such Damages recovered by any third party for which a Party owes another Party an indemnity under this Agreement shall not be waived.

(d) The Parties will make appropriate adjustments for any insurance proceeds actually received by the Indemnified Party in determining Damages for purposes of this Article 7. All indemnification payments under this Article 7 will be deemed to be adjustments to the amounts paid to Sellers pursuant to Article 2. Any liability for indemnification under this Agreement shall be determined without duplication of recovery by reason of the state of facts giving rise to such liability constituting a breach of more than one representation, warranty, covenant or agreement.

(e) Each Indemnified Party seeking indemnification hereunder shall use commercially reasonable efforts to mitigate any Damages that it asserts under this Article 7, but any reasonable costs and expenses (other than internal costs and expenses) incurred in connection therewith shall constitute Damages.

7.6 Exclusive Remedy. IN THE ABSENCE OF FRAUD, AFTER THE CLOSING THE RIGHT OF THE PARTIES TO ASSERT INDEMNIFICATION CLAIMS AND RECEIVE INDEMNITY PAYMENTS UNDER THIS AGREEMENT IS THE SOLE AND EXCLUSIVE RIGHT AND REMEDY EXERCISABLE BY THE PARTIES WITH RESPECT TO ANY DAMAGES ARISING OUT OF ANY BREACH BY ANY PARTY OF ANY

REPRESENTATION, WARRANTY, COVENANT OR AGREEMENT OF SUCH PARTY SET FORTH IN THIS AGREEMENT OR OTHERWISE RELATING TO THE CONTEMPLATED TRANSACTIONS. NO PARTY WILL HAVE ANY OTHER REMEDY (STATUTORY, EQUITABLE, COMMON LAW OR OTHERWISE) AGAINST ANY OTHER PARTY WITH RESPECT TO SUCH MATTERS, AND ALL SUCH OTHER REMEDIES ARE HEREBY WAIVED. WITHOUT LIMITING THE FOREGOING, IN THE ABSENCE OF FRAUD, EACH OF THE PARTIES ACKNOWLEDGES AND AGREES THAT SUCH PARTY WILL NOT HAVE ANY REMEDY AFTER THE CLOSING FOR ANY BREACH OF ANY REPRESENTATION, WARRANTY, COVENANT OR AGREEMENT SET FORTH IN THIS AGREEMENT, EXCEPT AS EXPRESSLY PROVIDED IN THIS ARTICLE 7.

7.7 Tax Treatment. Indemnification payments made pursuant to this Article 7 may be treated as adjustments of the Purchase Price as permitted by applicable Laws and Regulations.

ARTICLE 8
TERMINATION

8.1 Termination of Agreement. The Parties may terminate this Agreement as provided below:

(a) Buyer and Sellers may terminate this Agreement by mutual written consent at any time prior to the Closing;

(b) Buyer may terminate this Agreement by giving written notice to the Seller Representative (i) at any time prior to the Closing in the event that any Seller has breached in any material respect any representation, warranty or covenant contained in this Agreement, Buyer has notified the Seller Representative of the breach, and the breach has continued without cure for a period of 30 days after the notice of breach or (ii) at any time following February 28, 2014 (the "Termination Date") if the Closing shall not have occurred on or before the Termination Date; or

(c) Sellers may terminate this Agreement by giving written notice to Buyer (i) at any time prior to the Closing in the event that Buyer has breached in any material respect any representation, warranty or covenant contained in this Agreement, the Seller Representative has notified Buyer of the breach, and the breach has continued without cure for a period of 30 days after the notice of breach or (ii) at any time following the Termination Date if the Closing shall not have occurred on or before the Termination Date.

8.2 Effect of Termination.

(a) In the event that this Agreement is terminated by either Party pursuant to Section 8.1 above, then, except as expressly hereinafter provided, this Agreement shall become void and have no effect; *provided, however,* that (i) the provisions of Sections 5.2, 5.11, 7.4, 7.5(c), 7.5(d) and 7.5(e), this Article 8, Article 9 and Article 10 shall survive any such termination and (ii) each Party shall, in all events, remain bound by and continue to be subject to the terms of the Confidentiality Agreement.

(b) In the event that (i) Buyer terminates this Agreement pursuant to

Section 8.1(b) above, (ii) any Seller has knowingly taken any action or knowingly omitted to take any action where such action or omission to take any such action resulted in the breach or failure in any material respect of any of such Seller's representations or warranties set forth herein or any covenants of such Seller which are to be performed or observed at or prior to the Closing and (iii) as of the date of such termination, Buyer has not breached in any material respect any representation, warranty or covenant of Buyer contained in this Agreement (including Buyer's failure to consummate the transactions contemplated by this Agreement upon satisfaction of the conditions set forth in Section 6.2 above), then, subject to the limitations set forth in Section 7.5(c) above and this Section 8.2, Buyer shall be entitled to all remedies available at law or in equity (including specific performance to the extent that a court of competent jurisdiction determines that Buyer is entitled to such remedy).

(c) In the event that (i) Sellers terminate this Agreement pursuant to Section 8.1(c) above , (ii) Buyer has knowingly taken any action or knowingly omitted to take any action where such action or omission to take any such action resulted in the breach or failure in any material respect of any of Buyer's representations or warranties set forth herein or any covenants of Sellers which are to be performed or observed at or prior to the Closing and (iii) as of the date of such termination, no Seller has not breached in any material respect any representation, warranty or covenant of such Seller contained in this Agreement (including such Seller's failure to consummate the transactions contemplated by this Agreement upon satisfaction of the conditions set forth in Section 6.1 above), then, subject to the limitations set forth in Section 7.5(c) above and this Section 8.2, Sellers shall be entitled to all remedies available at law or in equity (including specific performance to the extent that a court of competent jurisdiction determines that Sellers are entitled to such remedy).

(d) In the event that (i) this Agreement terminates pursuant to Section 8.1 above and (ii) the conditions described in either Section 8.2(b) or Section 8.2(c) above have not been satisfied, then no Party shall have any obligations or liabilities hereunder except for the obligations and liabilities with respect to Sections 5.2 and 5.11, this Article 8, Article 9 and Article 10.

ARTICLE 9
SELLER MATTERS

9.1 Appointment of Seller Representative .

(a) By the execution and delivery of this Agreement, each Seller, effective immediately, hereby irrevocably constitutes and appoints PVOG as the true and lawful agent and attorney-in-fact with full authority and power of substitution to act in the name, place and stead of such Seller with respect to the performance of the obligations and rights of Sellers under this Agreement (the "Seller Representative") and any action contemplated to be taken by the Seller Representative hereunder in connection therewith, including the power to (i) determine the Capital Adjustment, make adjustments to the Base Purchase Price and prepare the Preliminary Settlement Statement and the Proposed Final Settlement Statement, (ii) receive from Buyer any amounts owed to Sellers pursuant to this Agreement (including any amounts owed to Sellers pursuant to Section 2.3 or Section 2.5) and disburse to each Seller such Seller's Pro Rata Share thereof, (iii) settle or pursue claims or controversies on behalf of Sellers with respect to amounts owed by or to Sellers pursuant to this Agreement (including pursuant to Section 2.3(d)), (iv) give and receive any consents or notices required or permitted by this Agreement and (v) do or refrain from doing all such further acts and things, and execute, deliver and receive all such documents, waivers, extensions and amendments as the Seller Representative shall deem necessary or appropriate in its sole discretion in connection with the administration of this Agreement (and any such actions shall be binding on Sellers). Each of the Parties hereto covenants and agrees that it will not take any action to voluntarily revoke the power of attorney conferred in this Section 9.1. By its execution of this Agreement, PVOG hereby (1) accepts its appointment and authorization to act as the Seller Representative and attorney-in-fact on behalf of each Seller in accordance with the terms of this Agreement, and (2) agrees to perform its obligations under, and otherwise comply with, this Section 9.1.

(b) Buyer, Sellers and any other Person may conclusively and absolutely rely, without inquiry, upon any action of the Seller Representative as the action of each Seller hereunder and in all matters referred to herein, and each Seller confirms all that the Seller Representative shall do or cause to be done in good faith by virtue of its appointment as the Seller Representative.

(c) The Seller Representative may resign as the Seller Representative for any reason and at any time by written notice to Buyer and Sellers. If at any time the Seller Representative (or any successor Seller Representative) resigns from such Person's position as the Seller Representative, a successor shall be designated by the mutual agreement of each Seller or, absent such mutual agreement, by a majority vote of the Sellers, as soon as practicable (but in no event later than 30 days after resignation of the Seller Representative or successor Seller Representative, as applicable), and the Parties shall thereafter be notified in writing of such designation; *provided, however,* that the Parties agree that a court of competent jurisdiction sitting in Harris County, Texas shall have the authority to appoint a successor Seller Representative in the event that a successor Seller Representative is not designated within the 30-day period pursuant to the provisions hereof.

(d) The Seller Representative shall have no duties except those which are expressly set forth herein. Each Seller hereby consents and agrees to all actions or inactions taken or omitted to be taken, in each case in good faith, by the Seller Representative under this Agreement. Notwithstanding anything in this Agreement to the contrary, including the provisions set forth in Article 7, each Seller hereby agrees to severally, and not jointly or jointly and severally, indemnify and hold harmless the Seller Representative from and against all Damages incurred in connection with the performance of its duties under this Agreement, excluding such Damages caused by the gross negligence, bad faith or willful misconduct of the Seller Representative. The Seller Representative shall be entitled and is hereby granted the right to set off and deduct any such unpaid, unsatisfied Damages from any amounts owed to a Seller pursuant to this Agreement.

(e) Each of the Parties acknowledges and agrees that the Seller Representative shall not be liable, responsible or accountable in Damages or otherwise to any Party by reason of, arising from or relating to any action taken or failure to act on behalf of Sellers, unless caused by the gross negligence, bad faith or willful misconduct of the Seller Representative.

(f) The Seller Representative shall be fully protected in relying in good faith upon the records of Sellers and upon such information, opinions, reports or statements presented to the Seller Representative by any of its accountants, consultants, brokers, financial advisors, legal counsel and other professionals as to matters the Seller Representative reasonably believes are within such Person's professional or expert competence.

(g) IN NO EVENT SHALL THE SELLER REPRESENTATIVE BE LIABLE, DIRECTLY OR INDIRECTLY, FOR ANY SPECIAL, INDIRECT OR CONSEQUENTIAL LOSSES OR DAMAGES OF ANY KIND WHATSOEVER (INCLUDING LOST PROFITS), EVEN IF THE SELLERS' REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH LOSSES OR DAMAGES REGARDLESS OF THE FORM OF ACTION, UNLESS CAUSED BY THE GROSS NEGLIGENCE, BAD FAITH OR WILLFUL MISCONDUCT OF THE SELLER REPRESENTATIVE.

(h) EXCEPT TO THE EXTENT PROHIBITED BY LAW, EACH SELLER UNDERSTANDS AND AGREES THAT INDEMNIFICATION PURSUANT TO THIS SECTION 9.1 SHALL INCLUDE INDEMNIFICATION FOR THE SELLER REPRESENTATIVE'S OWN NEGLIGENCE OR UNDER THEORIES OF STRICT LIABILITY TO THE FULLEST EXTENT PERMITTED BY LAW, BUT SHALL EXCLUDE INDEMNIFICATION FOR THE SELLER REPRESENTATIVE'S GROSS NEGLIGENCE, BAD FAITH OR WILLFUL MISCONDUCT.

(i) The provisions set forth in this Section 9.1 shall survive the resignation of the Seller Representative and the termination of this Agreement; *provided, however,* that the authorizations of the Seller Representative shall be effective only until its rights and obligations under this Agreement terminate by virtue of the termination of any and all obligations of Sellers and of Buyer under this Agreement.

(j) The appointment and grant of power and authority by each Seller under this Section 9.1 is coupled with an interest and is irrevocable and shall not be terminated by any act of such Party or by operation of law, whether by the death or incapacity of such Party or by the occurrence of any other event.

9.2 Release of Seller Claims . Save and except for (i) any rights of any Seller under this Agreement and (ii) any claims of PVOG against any Seller for any outstanding System Costs as defined in that certain Gathering System Agreement dated as of June 1, 2012 by and among Sellers, each Seller, effective as of the Closing, for itself and its representatives and assigns, hereby finally, unconditionally, irrevocably and absolutely releases, acquits, remises and forever discharges each of the other Sellers and any of their Affiliates, predecessors, successors, assigns, agents and representatives (collectively, the "Releasees") from any and all claims, counterclaims, demands, causes of action, liabilities costs, expenses and fees (including attorneys' fees and court costs), existing as of the Closing accruing to such Seller in connection with the Purchased Assets (the "Claims"), and finally, unconditionally, irrevocably and absolutely waives any and all offsets and defenses, in each case related to any action, inaction, event, circumstance or occurrence occurring or alleged to have occurred on or prior to the Closing with respect to such Claims, whether known or unknown, absolute or contingent, matured or unmatured, foreseeable or unforeseeable, presently existing or hereafter discovered, at law, in equity or otherwise, whether arising by statute, common law, in contract, in tort or otherwise, that such Seller may now have or that might subsequently accrue to it, including without limitation those against any current or former officer, director, manager, partner, employee or agent of any Releasee.

ARTICLE 10
MISCELLANEOUS

10.1 Amendment and Waiver. The Parties may, by mutual written agreement, amend this Agreement in any respect, and either party, as to such Party, may (i) extend the time for the performance of any of the obligations of the other Party; (ii) waive any inaccuracies in representations and warranties by the other Party; (iii) waive compliance by the other Party with any of the covenants or agreements contained herein and performance of any obligations by the other Party; and (iv) waive the fulfillment of any condition that is precedent to the performance by such Party of any of its obligations under this Agreement. To be effective, any such extension or waiver must be in writing and be signed by the Party providing such waiver or extension, as the case may be. No such extension or waiver by any Party, nor any waiver by any Party of any breach of any provision of this Agreement, shall operate or be construed as a waiver of any subsequent breach, whether or not similar. No failure or any delay by any Party in exercising any right, power or privilege under this Agreement or any of the other Transaction Documents shall operate as a waiver of such right, power or privilege, and no single or partial exercise of any such right, power or privilege shall preclude any other or further exercise of such right, power or privilege or the exercise of any other right, power or privilege. Except as otherwise provided in this Agreement, the rights and remedies herein provided are cumulative and are not alternative.

10.2 Successors and Assigns. The provisions of this Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns; *provided, however,* that no Party may assign, delegate or otherwise transfer any of its rights or obligations under this Agreement without the consent of the other Party. Any transfer or assignment in violation of this Section 10.2 shall be void *ab initio*.

10.3 Notices. All notices, requests, demands and communications required or permitted under this Agreement shall be in writing, and any communication or delivery hereunder shall be deemed to have been duly made when personally delivered to the individual indicated below, or if mailed or by facsimile or email transmission, when received by the Party charged with such notice and addressed as follows:

If to Sellers:

Penn Virginia Oil & Gas, L.P.
Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087-4564
Attention: H. Baird Whitehead
Fax: (610) 687-3688
Email: baird.whitehead@pennvirginia.com

and

Ted Collins, Jr.
508 West Wall Street, Suite 1200
Midland, Texas 79701
Fax: (432) 686-0302
Email: tedc@collinsandware.com

and

Plein Sud Holdings, LLC
3131 McKinney Ave, Suite 439
Dallas, Texas 75204
Attention: J. Patrick Collins
Fax: (214) 628-9160
Email: jpcollins@cortezoil.com

With a copy to:

Penn Virginia Oil & Gas, L.P.
840 Gessner, Suite 800
Houston, Texas 77024
Attention: Jill T. Zivley
Fax: (713) 722-6610
Email: jill.zivley@pennvirginia.com

and

Penn Virginia Corporation
Four Radnor Corporate Center, Suite 200
100 Matsonford Road
Radnor, Pennsylvania 19087-4564
Attention: Nancy M. Snyder
Fax: (610) 687-3688
Email: nancy.snyder@pennvirginia.com

If to Buyer:

HPIP Lavaca, LLC
c/o ArcLight Capital Partners, LLC
200 Clarendon Street, 55th Floor
Boston, Massachusetts 02117
Attention: Christine Miller
Fax: (617) 867-4698
Email: cmiller@arclightcapital.com

With a copy to:

American Midstream Partners, L.P.
1614 15^{th} Street, Suite 300
Denver, Colorado 80202
Attention: William B. Mathews
Fax: (720) 457-6040
Email: bmathews@americanmidstream.com

Any Party may, by written notice so delivered to the other Parties, change the address or individual to which delivery shall thereafter be made. If any Party rejects or otherwise refuses to accept a notice, or if the notice cannot be delivered because of a change in address for which no notice was given to the Party attempting to give or make such notice, such notice shall be deemed to have been received upon such rejection, refusal or such inability to deliver.

10.4 Severability. The Parties agree that (i) the provisions of this Agreement shall be severable in the event that any provision hereof is held by a court of competent jurisdiction to be invalid, void or otherwise unenforceable, (ii) such invalid, void or otherwise unenforceable provision shall be automatically replaced by another provision which is as similar as possible in terms to such invalid, void or otherwise unenforceable provision but which is valid and enforceable and (iii) the remaining provisions shall remain enforceable to the fullest extent permitted by law.

10.5 No Third Party Beneficiaries. Nothing in this Agreement, express or implied, is intended to or shall (i) confer on any person or entity other than the Parties (and the Indemnified Parties referred to in Article 7 above) and their respective successors or assigns any rights (including third party beneficiary rights), remedies, obligations or liabilities under or by reason of this Agreement, or (ii) constitute the Parties as partners or as participants in a joint venture. This Agreement shall not provide third parties with any remedy, claim, liability, reimbursement, cause of action or other right in excess of those existing without reference to the terms of this Agreement. No third party shall have any right, independent of any right which may exist irrespective of this Agreement, under or granted by this Agreement, to bring any suit at law or equity for any matter governed by or subject to the provisions of this Agreement.

10.6 Construction. Buyer and Sellers have participated jointly in the negotiation and drafting of this Agreement and the Transaction Documents. In the event that any ambiguity or question of intent or interpretation arises, this Agreement and the Transaction Documents shall be construed as if drafted jointly by Buyer and Sellers, and no presumption or burden of proof shall arise favoring or disfavoring any party by virtue of the authorship of any of the provisions of this Agreement or the other Transaction Documents.

10.7 References and Titles. All references to cash or monetary amounts refer to U.S. Dollars only unless specifically stated to be in the currency of another government. The words "this Agreement," "herein," "hereby," "hereunder" and "hereof," and words of similar import, refer to this Agreement as a whole and not to any particular subdivision, unless expressly so limited. The words "this Article," "this Section" and "this subsection," and words of similar import, refer only to the Articles, Sections or subsections, respectively, hereof in which such words occur. The word "including" (in its various forms) means " including without limitation." Any reference to any federal, state or local statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. Pronouns in masculine, feminine or neuter genders shall be construed to state and include any other gender and words, terms and titles (including terms defined herein) in the singular form shall be construed to include the plural and vice versa, unless the context otherwise expressly requires. Unless the context otherwise requires, all defined terms contained herein shall include the singular and plural and the conjunctive and disjunctive forms of such defined terms.

10.8 Exhibits and Schedules. All exhibits and schedules annexed hereto or referred to herein are hereby incorporated in and made a part of this Agreement as if set forth in full herein.

10.9 Headings. The headings preceding the text of the articles, sections and paragraphs hereof are inserted solely for convenience of reference and shall not constitute a part of this Agreement nor shall they affect its meaning, construction or effect.

10.10 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but which together shall constitute one and the same instrument. Any executed counterpart delivered by facsimile or other means of electronic transmission shall be deemed an original for all purposes.

10.11 Entire Agreement. This Agreement, together with the exhibits and schedules attached hereto and the other Transaction Documents, and the Confidentiality Agreement constitute the entire understanding of the Parties with respect to the subject matter hereof, superseding all prior negotiations, discussions, agreements or understandings, written or oral, between the Parties with respect to the subject matter hereof.

10.12 Applicable Law. This Agreement shall be governed by, and construed and interpreted in accordance with the Laws and Regulations of the State of Texas, without giving effect to any choice or conflict of law provision or rule (whether of the State of Texas or any other jurisdiction) that would cause the application of the Laws and Regulations of any jurisdiction other than the State of Texas.

10.13 Several Obligations of Sellers. Except as provided in Section 7.2, the obligations of each Seller under or arising out of this Agreement are several and not joint. Without limiting the generality of the foregoing, any representation, warranty or covenant of a Seller contained in this Agreement (other than the representations and warranties set forth in Section 4.2) is made by such Seller only with respect to itself and its own interest in the Purchased Assets and such Seller shall not be liable for any breach (or Damages arising out of a breach) by another Seller of any of its representations, warranties or covenants contained in this Agreement (other than the representations and warranties set forth in Section 4.2).

ARTICLE 11
GUARANTEE

Buyer Guarantor shall cause payment of all amounts owed by Buyer to Sellers pursuant to Article 2 hereunder if, as and when provided in this Agreement. In no event shall Buyer Guarantor have any greater liability than Buyer pursuant to this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized officers as of the date first written above.

SELLERS:

PENN VIRGINIA OIL & GAS, L.P.

By: Penn Virginia Oil & Gas GP LLC,
its general partner

By: /s/ H. Baird Whitehead
Name: H. Baird Whitehead
Title: President and Chief Executive Officer

By: /s/ Ted Collins, Jr.
Ted Collins, Jr.

PLEIN SUD HOLDINGS, LLC

By: /s/ J. Patrick Collins
Name: J. Patrick Collins
Title: Member

BUYER:

HPIP LAVACA, LLC

By: /s/ Daniel R. Revers
Name: Daniel R. Revers
Title: President

The undersigned hereby executes this Agreement for the sole purpose of its obligations pursuant to Article 11 of this Agreement, subject to the limitations set forth therein.

ArcLight Energy Partners Fund V, L.P.

By: ArcLight PEF GP V, LLC, its general partner

By: ArcLight Capital Holdings, LLC, its Manager

By: /s/ Daniel R. Revers
Name: Daniel R. Revers
Title: Manager

Exhibit 12.1

Penn Virginia Corporation and Subsidiaries
Statement of Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends
(in thousands, except ratios)

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Earnings:					
Income (loss) from continuing operations before income taxes	$ (220,766)	$ (173,291)	$ (221,070)	$ (108,178)	$ (216,750)
Fixed charges	97,903	66,616	62,002	60,003	52,539
Capitalized interest	(5,266)	(803)	(1,983)	(1,384)	(2,318)
Preferred stock dividend requirements	(10,647)	(2,793)	—	—	—
	$ (138,776)	$ (110,271)	$ (161,051)	$ (49,559)	$ (166,529)
Fixed charges:					
Interest expense	$ 78,841	$ 59,339	$ 56,216	$ 53,679	$ 44,231
Capitalized interest	5,266	803	1,983	1,384	2,318
Rent factor	3,149	3,681	3,803	4,940	5,990
Preferred stock dividend requirements	10,647	2,793	—	—	—
	$ 97,903	$ 66,616	$ 62,002	$ 60,003	$ 52,539
Ratio of earnings to fixed charges and preferred stock dividends [1]	—	—	—	—	—

[1] During 2013, 2012, 2011, 2010 and 2009, earnings were deficient by $236,679, $176,887, $223,053, $109,562 and $219,068, respectively, regarding the coverage of fixed charges and preferred stock dividends.

Exhibit 21.1

Subsidiaries of Penn Virginia Corporation

Name	Jurisdiction of Organization
Penn Virginia Holding Corp.	Delaware
Penn Virginia Oil & Gas Corporation	Virginia
Penn Virginia Oil & Gas, L.P.	Texas
Penn Virginia Oil & Gas GP LLC	Delaware
Penn Virginia Oil & Gas LP LLC	Delaware
Penn Virginia MC Corporation	Delaware
Penn Virginia MC Energy L.L.C.	Delaware
Penn Virginia MC Operating Company L.L.C	Delaware
Penn Virginia MC Gathering Company L.L.C.	Oklahoma
Penn Virginia Resource Holdings Corp.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Penn Virginia Corporation:

We consent to the incorporation by reference in the registration statements on Form S-3 (No. 333-183365) and on Form S-8 (No. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, 333-159304, 333-173990 and 333-188587) of Penn Virginia Corporation of our report dated February 24, 2014, with respect to the consolidated balance sheets of Penn Virginia Corporation as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2013, and the effectiveness of internal control over financial reporting as of December 31, 2013, which report appears in the December 31, 2013 annual report on Form 10-K of Penn Virginia Corporation.

/s/ KPMG LLP

Houston, Texas
February 24, 2014

Exhibit 23.2

CONSENT OF WRIGHT & COMPANY, INC.

As independent petroleum consultants, Wright & Company, Inc. hereby consents to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-59647, 333-82304, 333-96463, 333-96465, 333-82274, 333-103455, 333-143514, 333-159304, 333-173990, and 333-188587) and Form S-3 (No. 333-183365) of Penn Virginia Corporation of information from our reserves report titled “Evaluation of Oil and Gas Reserves To the Interests of Penn Virginia Corporation, In Certain Properties Located in Various States, Pursuant to the Requirements of the Securities and Exchange Commission, Effective January 1, 2014, Job 15.1543,” and dated January 27, 2014, and all references to our firm included in or made a part of the Penn Virginia Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about February 24, 2014.

Wright & Company, Inc.
TX Firm Reg. No. F-12302

/s/ D. Randall Wright

By: D. Randall Wright
President

Brentwood, Tennessee
February 24, 2014

Exhibit 31.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, H. Baird Whitehead, President and Chief Executive Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: February 24, 2014

/s/ H. BAIRD WHITEHEAD

H. Baird Whitehead
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of Penn Virginia Corporation (the "Registrant"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this "Report");

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

   (d) Disclosed in this Report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of the Registrant's board of directors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: February 24, 2014

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn Virginia Corporation (the “Company”) on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, H. Baird Whitehead, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2014

/s/ H. BAIRD WHITEHEAD

H. Baird Whitehead
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Steven A. Hartman, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2014

/s/ STEVEN A. HARTMAN

Steven A. Hartman
Senior Vice President and Chief Financial Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

January 27, 2014

Penn Virginia Corporation
840 Gessner Road, Suite 800
Houston, TX 77024

Attention: Mr. Frank E. Falbo, Jr.

SUBJECT: Evaluation of Oil and Gas Reserves
To the Interests of Penn Virginia Corporation
In Certain Properties Located in Various States
Pursuant to the Requirements of the
Securities and Exchange Commission
Effective January 1, 2014
Job 13.1543

At the request of Penn Virginia Corporation (PVA), Wright & Company, Inc. (Wright) has performed an evaluation to estimate proved reserves and associated cash flow and economics from certain properties to the subject interests. This evaluation was authorized by Mr. Frank E. Falbo, Jr. of PVA. Projections of the reserves and cash flow to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered applicable at the effective date. This reserves evaluation is pursuant to the financial reporting requirements of the Securities and Exchange Commission (SEC) as specified in Regulation S-X, Rule 4-10(a) and Regulation S-K, Rule 1202(a)(8). It is the understanding of Wright that the purpose of this evaluation is for inclusion in relevant registration statements or other filings to the SEC. The effective date of this report is January 1, 2014. The report was completed January 27, 2014. The following is a summary of the results of the evaluation.

Penn Virginia Corporation SEC Parameters	Proved Developed Producing (PDP)	Proved Developed Nonproducing (PDNP)	Total Proved Developed (PDP & PDNP)	Proved Undeveloped (PUD)	Total Proved (PDP, PDNP & PUD)
Net Reserves to the Evaluated Interests					
Oil, Mbbl:	18,994.623	311.740	19,306.363	41,390.180	60,696.547
Gas, MMcf:	146,487.078	16,673.629	163,160.703	158,932.719	322,093.438
NGL, Mbbl:	7,503.166	1,037.807	8,540.973	13,425.017	21,965.992
Oil Equivalent, MBOE: (6 Mcf = 1 BOE)	50,912.302	4,128.485	55,040.787	81,303.934	136,344.779
Cash Flow (BTAX), M$					
Undiscounted:	1,742,093.750	29,821.779	1,771,915.500	1,981,329.000	3,753,245.500
Discounted at 10% Per Annum:	953,105.688	9,909.363	963,015.062	753,614.750	1,716,630.125

Please note numbers in table may not add due to rounding techniques in the ARIES™ petroleum software program.

The properties evaluated in this report are located in the states of Louisiana, Mississippi, Oklahoma, Pennsylvania, and Texas. According to PVA, the total proved reserves included in this evaluation represent 100 percent of the reported total proved reserves of PVA.

Proved oil and gas reserves are those quantities of oil and gas which can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods, and government regulations.

As specified by the SEC regulations, when calculating economic producibility, the base product price must be the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the prior 12-month period. The benchmark base prices used for this evaluation were $96.78 per barrel for West Texas Intermediate oil at Cushing, Oklahoma and $3.670 per million British thermal units (MMBtu) for natural gas at Henry Hub, Louisiana. These benchmark base prices were adjusted for energy content, quality, and basis differential, as appropriate. The average adjusted product prices used to estimate proved reserves are $103.11 per barrel of oil and $3.471 per thousand standard cubic feet (Mcf) of gas. The Natural Gas Liquids (NGL) product price was estimated to be approximately 30 percent of the base oil price, resulting in a weighted average adjusted price of $31.10 per barrel. The base product prices were held constant for the life of the properties.

Oil and other liquid hydrocarbon volumes are expressed in thousands of United States (U.S.) barrels (Mbbl), one barrel equaling 42 U.S. gallons. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. For purposes of this report, quantities of natural gas are converted into equivalent quantities of oil at the ratio of 6 Mcf = 1 barrel of oil equivalent (BOE). No adjustment of the individual gas volumes to a common pressure base has been made.

Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, standard state and county taxes or fees, operating expenses, and investments, as applicable. The cash flow is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. The Cash Flow (BTAX) was discounted monthly at an annual rate of 10.00 percent (PCT) in accordance with the reporting requirements of the SEC.

The estimates of reserves contained in this report were determined by accepted industry methods, and the procedures used in this evaluation are appropriate for the purpose served by the report. Where sufficient production history and other data were available, reserves for producing properties were determined by extrapolation of historical production or sales trends. Analogy to similar producing properties was used for development projects and for those properties that lacked sufficient production history to yield a definitive estimate of reserves. When appropriate, Wright may have also utilized volumetric calculations and log correlations in the determination of estimated ultimate recovery (EUR). These calculations are often based upon limited log and/or core analysis data and incomplete formation fluid and rock data. Since these limited data must frequently be extrapolated over an assumed drainage area, subsequent production performance trends or material balance calculations may cause the need for significant revisions to the estimates of reserves. Wright has used all methods and procedures as it considered necessary under the circumstances to prepare this report.

Oil and gas reserves were evaluated for the proved developed producing (PDP), proved developed nonproducing (PDNP) and proved undeveloped (PUD) reserves categories. The summary classification of total proved developed reserves combines the PDP and PDNP categories, and the summary classification of total proved reserves combines the total proved developed and PUD categories. In preparing this evaluation, no attempt has been made to quantify the element of uncertainty associated with any category. Reserves were assigned to each category as warranted. Wright is not aware of any local, state, or federal regulations that would preclude PVA from continuing to produce from currently active wells or to fully develop those properties included in this report.

There are significant uncertainties inherent in estimating reserves, future rates of production, and the timing and amount of future costs. The estimation of oil and gas reserves must be recognized as a subjective process that cannot be measured in an exact way, and estimates of others might differ materially from those of Wright. The accuracy of any reserves estimate is a function of the quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates or changes in the analogous properties may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

All data utilized in the preparation of this report were provided by PVA. No inspection of the properties was made as this was not considered to be within the scope of this evaluation. Wright has not independently verified the accuracy and completeness of information and data furnished by PVA with respect to ownership interests, oil and gas production or sales, historical costs of operation and development, product prices, or agreements relating to current and future operations and sales of production. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by PVA with regard to product pricing, appropriate adjustments, lease operating expenses, and capital investments for drilling the undeveloped locations. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, Wright did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. In accordance with the requirements of the SEC, all operating costs were held constant for the life of the properties.

In accordance with the instructions of PVA, abandonment costs net of salvage values were included, as appropriate. Wright has not performed a detailed study of the abandonment costs nor the salvage values and offers no opinion as to PVA's calculations.

Wright is not aware of any potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this evaluation for potential property restoration, liability, or clean up of damages, if any, that may be necessary due to past or future operating practices.

Wright is an independent petroleum consulting firm founded in 1988 and owns no interests in the oil and gas properties covered by this report. No employee, officer, or director of Wright is an employee, officer, or director of PVA, nor does Wright or any of its employees have direct financial interest in PVA. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this report.

This report is prepared for the information of PVA, its shareholders, and for the information and assistance of its independent public accountants in connection with their review of and report upon the financial statements of PVA, and for reporting disclosures as required by the SEC. This report is also intended for public disclosure as an exhibit in filings made to the SEC by PVA.

Based on data and information provided by PVA, and the specified economic parameters, operating conditions, and government regulations considered applicable at the effective date, it is Wright's conclusion that this report provides a fair and accurate representation of the oil and gas reserves to the interests of PVA in those certain properties included in this report.

The professional qualifications of the petroleum consultants responsible for the evaluation of the reserves and economics information presented in this report meet the standards of Reserves Estimator as defined in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information* as promulgated by the Society of Petroleum Engineers.

It has been a pleasure to serve you by preparing this evaluation. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.
TX Reg. No. F-12302

By: /s/ D. Randall Wright
D. Randall Wright
President