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, 2016
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)

14701 St. Mary's Lane, Suite 275
Houston, TX 77079
(Address of principal executive offices)
Registrant's telephone number, including area code: **(713) 722-6500**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 Par Value	**NASDAQ Global Select Market**

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

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 less than $1,000,000 as of June 30, 2016 (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 OTC Pink. 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.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☒ No ☐

As of March 10, 2017, 14,992,018 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 3, 2017, are incorporated by reference in Part III of this Form 10-K.

PENN VIRGINIA CORPORATION
ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2016

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Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, 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:

- potential adverse effects of the completed Chapter 11, or bankruptcy, proceedings on our liquidity, results of operations, brand, business prospects, ability to retain financing and other risks and uncertainties related to our emergence from bankruptcy;
- the ability to operate our business following emergence from bankruptcy;
- our ability to satisfy our short-term and long-term liquidity needs, including our inability to generate sufficient cash flows from operations or to obtain adequate financing to fund our capital expenditures and meet working capital needs;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- our new capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in the current commodity price environment;
- the sustained decline in and volatility of commodity prices for oil, natural gas liquids, or NGLs, and natural gas;
- our ability to develop, explore for, acquire and replace oil and natural gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, natural gas liquids and natural gas;
- our ability to contract for drilling rigs, frac crews, 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 our 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 that estimated in our proved oil and natural gas reserves;
- drilling and operating risks;
- concentration of assets;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;
- costs or results of any strategic alternatives
- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- counterparty risk related to the ability of these parties to meet their future obligations;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties relating to general domestic and international economic and political conditions; and

- other factors set forth in our periodic filings with the Securities and Exchange Commission, including the risks set forth in Part I, Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2016.

Additional information concerning these and other factors can be found in our press releases and public 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. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

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.

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.

Borrowing base. The value assigned to a collection of borrower’s assets used by lenders to determine an initial and/or continuing amount for loans. In the case of oil and gas exploration and development companies, the borrowing base is generally based on proved developed reserves.

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.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface temperature and pressure.

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.

Drilling carry. A working interest that will be carried through the drilling and completion of a 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.

EUR. Estimated ultimate reserves, the sum of reserves remaining as of a given date and cumulative production as of that date.

GAAP. Accounting principles generally accepted in the Unites States of America.

Gas lift. A method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas for lifting the well fluids.

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.

Henry Hub. The Erath, Louisiana settlement point price for natural gas.

IP. Initial production, a measurement of a well’s production at the outset.

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.

Nasdaq. The NASDAQ Global Select Market.

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.

PV10. A non-GAAP measure representing the present value of estimated future oil and gas revenues, net of estimated direct costs, discounted at an annual discount rate of 10%. PV10 is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for any GAAP measure. PV10 does not purport to represent the fair value of oil and gas properties.

Reservoir. A porous and permeable underground formation containing a natural accumulation of hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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.

SEC. United States Securities and Exchange Commission.

Service well. A well drilled or completed for the purpose of supporting production in an existing field.

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.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production.

Unconventional. Generally refers to hydrocarbon reservoirs that lack discrete boundaries that typically define conventional reservoirs. Examples include 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, 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

We are an independent oil and gas company engaged in the onshore exploration, development and production of crude oil, NGLs and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale field, or the Eagle Ford, in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash. In August 2016, we terminated our remaining operations in the Marcellus Shale in Pennsylvania and are currently in the process of remediating the sites of our former wells in that region.

We were incorporated in the Commonwealth of Virginia in 1882. On December 28, 2016, our common stock began trading publicly on the Nasdaq under the symbol "PVAC." Our headquarters and corporate office is located in Houston, Texas. We also have an operations office near our Eagle Ford assets in South Texas.

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.

We lease a highly contiguous position of approximately 54,000 net acres (as of March 10, 2017) in the core liquids-rich area or "volatile oil window" of the Eagle Ford in Gonzales and Lavaca Counties in Texas, which we believe contains a substantial number of drilling locations that will support a multi-year drilling inventory.

In 2016, our total production was comprised of 69 percent crude oil, 16 percent NGLs and 15 percent natural gas. Crude oil accounted for 87 percent of our product revenues. We generally sell our crude oil, NGL and natural gas products using short-term floating price physical and spot market contracts.

As of December 31, 2016, our total proved reserves were approximately 50 MMBOE, of which 53 percent were proved developed reserves and 74 percent were crude oil. Approximately 95 percent of our reserves were located in South Texas and 51 percent were proved developed reserves. As of December 31, 2016, we had 431 gross (254.9 net) productive wells, approximately 78 percent of which we operate, and owned approximately 130,000 gross (90,000 net) acres of leasehold and royalty interests, approximately 38 percent of which were undeveloped. We suspended our drilling program in February 2016 due primarily to our financial condition at that time as well as unfavorable industry economic conditions including depressed commodity prices. We resumed our drilling program in November 2016 subsequent to our emergence from bankruptcy (see discussion below). During 2016, we drilled and completed five gross (2.9 net) wells, all in the Eagle Ford and all during the period prior to the aforementioned suspension of our drilling program. For a more detailed discussion of our production, reserves, drilling activities, wells and acreage, see Part I, Item 2, "Properties."

Emergence from Bankruptcy Proceedings and Fresh Start Accounting

On May 12, 2016, or the Petition Date, we and eight of our subsidiaries, or the Chapter 11 Subsidiaries, filed voluntary petitions (*In re Penn Virginia Corporation, et al, Case No. 16-32395*) seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code, or the Bankruptcy Code, in the United States Bankruptcy Court for the Eastern District of Virginia, or the Bankruptcy Court.

On August 11, 2016, or the Confirmation Date, the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates, or the Plan, and we subsequently emerged from bankruptcy on September 12, 2016, or the Effective Date. For a more detailed discussion of our bankruptcy proceedings and our emergence from bankruptcy, see *Key Developments* included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Upon the Effective Date, we adopted and applied the relevant guidance with respect to the accounting and financial reporting for entities that have emerged from bankruptcy proceedings, or Fresh Start Accounting. The adoption of Fresh Start Accounting resulted in a new reporting entity, the Successor, for financial reporting purposes. To facilitate our discussion and analysis of our properties, financial condition and results of operations herein, we refer to the reorganized company as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. For a more detailed discussion of Fresh Start Accounting, see Note 5 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Key Contractual Arrangements

In the ordinary course of operating our business, we enter into a number of key contracts for services that are critical with respect to our ability to develop, produce and bring our production to market. The following is a summary of our most significant contractual arrangements.

Oil gathering and transportation service contracts. We have long-term agreements to provide gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in the South Texas region through 2041 as well as volume capacity support for certain downstream interstate pipeline transportation.

Natural gas service contracts. We have an agreement that provides gas lift, gathering, compression and transportation services for a substantial portion of our natural gas production in the South Texas region until 2039.

Drilling and Completion. From time to time we enter into short term drilling and completion contracts in the ordinary course of business to ensure availability of rigs and frac crews to satisfy our development program.

Major Customers

We sell a significant portion of our oil and gas production to a relatively small number of customers. For the year ended December 31, 2016, approximately 93 percent of our consolidated product revenues were attributable to three customers: Republic Midstream Marketing, LLC; Phillips 66 Company; and BP Products North America Inc.

Seasonality

Our sales volumes of oil and gas are dependent upon the number of producing wells 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, typically with higher pricing in the winter months.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. Some of our competitors 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. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers. 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 also 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. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles.

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, 2016, we have recorded asset retirement obligations of $2.5 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.

In addition, the United States Environmental Protection Agency, or the EPA, has designated energy extraction as one of six national enforcement initiatives, and has indicated that the agency will direct resources towards addressing incidences of noncompliance from natural gas extraction and production activities. 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 or 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 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 more stringent regulation under 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 or wetlands without a permit issued by the EPA, the Army Corps of Engineers, or the Corps, or the state is prohibited. The Clean Water Act has been interpreted by these agencies to apply broadly. The EPA and the Corps released a rule to revise the definition of "waters of the United States," or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. The rule is currently stayed, and the United States Supreme Court on January 13, 2017, agreed to hear a case regarding the question of which court had the jurisdiction over legal challenges to the WOTUS rule. In response to the stay and subsequent legal challenges, the EPA and the Corps resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. The WOTUS rule could significantly expand federal control of land and water resources across the U.S., triggering substantial additional permitting and regulatory requirements. However, the WOTUS rule also faces significant scrutiny from the Trump administration.

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. In 2016, the EPA finalized new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs

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 and Granite Wash formations. The EPA released the results of its comprehensive research study to investigate the potential adverse impacts of hydraulic fracturing on drinking water and ground water in December 2016, finding that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. These developments 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.

Chemical Disclosures Related to Hydraulic Fracturing. Certain states in which we operate have adopted regulations requiring the disclosure of chemicals used in the hydraulic fracturing process. For instance, Oklahoma 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.

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. For example, 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 existing 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.

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.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells, compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. Further, in May 2016, the EPA issued final NSPS governing methane emissions from the oil and natural gas industry as well as source determination standards for determining when oil and gas sources should be aggregated for CAA permitting and compliance purposes. The NSPS for methane extends the 2012 NSPS to completions of hydraulically fractured oil wells, equipment leaks, pneumatic pumps and natural gas compressors. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA has also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. These rules are expected to result in an increase to our operating costs and change to our operations. As a result of this continued regulatory focus, future federal and state regulations of the oil and natural gas industry remain a possibility and could result in increased compliance costs on our operations.

In November 2015, the EPA also revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. Certain areas of the country previously in compliance with the various National Ambient Air Quality Standards, including areas where we operate, may be reclassified as non-attainment areas. The EPA has not yet designated which areas of the country are out of attainment with the new ground level ozone standard, and it will take the states several years to develop compliance plans for their non-attainment areas. If the areas where we operate are reclassified as non-attainment areas, such reclassifications may make it more difficult to construct new or modified sources of emission control in those areas. While we are not able to determine the extent to which this new standard will impact our business at this time, it has the potential to have a material impact on our operations and cost structure.

In addition, on June 3, 2016, the EPA finalized a rule “aggregating” individual wells and other facilities and their collective emissions for purposes of determining whether major source permitting requirements apply under the CAA. These changes may introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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. Most recently in April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The EPA has issued the "Final Mandatory Reporting of Greenhouse Gases" Rule and a series of revisions to it, which requires operators of oil and gas production, natural gas processing, transmission, distribution and storage facilities and other 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. These rules do 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 certain circumstances, large sources of GHG emissions are subject to preconstruction permitting under the EPA's Prevention of Significant Deterioration program. This program historically has had minimal applicability to the oil and gas production industry. However, there can be no assurance that our operations will avoid applicability of these or similar permitting requirements, which impose costs relating to emissions control systems and the efforts needed to obtain the permit.

Additional GHG regulations potentially affecting our industry include those described above under the subheading "Clean Air Act" which relate to methane.

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 restricts activities that may affect endangered species or their habitats. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the Endangered Species Act. Moreover, the U.S. Fish and Wildlife Service continues its six-year effort to make listing decisions and critical habitat designations where necessary for over 250 species before the end of the agency's 2017 fiscal year, as required under a 2011 settlement approved by the U.S. District Court for the District of Columbia, and many hundreds of additional anticipated listing decisions have already been identified beyond those recognized in the 2011 settlement. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

Employees and Labor Relations

We had a total of 59 employees as of December 31, 2016. 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. Investors can obtain current and important information about the company from our website on a regular basis. We intend for our website to serve as a means of public dissemination of information for purposes of Regulation FD.

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 in the future. If any of the following risks actually occur, our business, financial condition, results of operations and cash flows could suffer and the trading price of our common stock could decline.

We recently emerged from bankruptcy, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our recent emergence could adversely affect our business and relationships with customers, employees and suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- our ability to renew existing contracts and compete for new business may be adversely affected;
- our ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities;
- our ability to attract and retain customers may be negatively impacted;
- we may experience challenges to the Plan; and
- we may incur legal costs associated with addressing claims under the Plan.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of the plan of reorganization and the transactions contemplated thereby and our adoption of fresh start accounting and the full cost method of accounting for oil and gas properties.

In connection with the disclosure statement we filed with the bankruptcy court, and the hearing to consider confirmation of the Plan, we prepared projected financial information to demonstrate to the bankruptcy court the feasibility of the Plan and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted Fresh Start Accounting and the full cost method of accounting for oil and gas properties. Accordingly, our future financial condition and results of operations may not be comparable to the financial condition or results of operations reflected in the Predecessor's historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock. The adoption of Fresh Start Accounting established a new basis for our assets and liabilities on the Effective Date. The adoption of the full cost method of accounting for oil and gas properties, as compared to the successful efforts method utilized by the Predecessor, results in the capitalization of additional costs as well as different methodologies to determine depletive write-offs and impairments. For a more detailed discussion of Fresh Start Accounting and the full cost method of accounting for oil and gas properties, see the discussion of "*Critical Accounting Estimates*" included in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" as well as Notes 3, 5 and 7 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

If we cannot obtain sufficient capital when needed, we will not be able to continue with our business strategy.

Our business strategy has historically included maintaining a portfolio of properties that provide long-term, profitable growth through development in areas that support sustainable, lower-risk, repeatable, high-return drilling projects. In the future, we may not be able to obtain financing in sufficient amounts or on acceptable terms when needed, which could adversely affect our operating results and prospects. If we cannot raise the capital required to implement our business strategy, we may be required to curtail operations, which could adversely affect our financial condition, results of operations and cash flows.

Prices for crude oil, NGLs and natural gas prices are dependent on many factors that are beyond our control.

Prices for crude oil, NGLs and natural gas are dependent on many 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;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions;
- prices and availability of, and demand for, alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and gas;
- the availability, proximity and capacity of gathering, processing, refining and transportation facilities;
- weather conditions; and
- domestic and foreign governmental relations, regulation and taxation.

It is impossible to predict future commodity price movements with certainty; however, 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 and borrowing capacity, 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.

The market price of our common stock is subject to volatility.

Upon our emergence from bankruptcy, our Predecessor common stock was canceled and we issued new common stock. Our common stock is currently listed on the Nasdaq. The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading that develops with our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the Plan, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the concentration of holdings of our common stock, the lack of comparable historical financial information due to our adoption of Fresh Start Accounting, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this report. Significant sales of our common stock, or the expectation of these sales, could materially and adversely affect the market price of our common stock.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

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 must make substantial capital expenditures to find, acquire, develop and produce new oil and gas reserves. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves with our cash flows from operating activities. Furthermore, external sources of capital may be limited.

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 substantial and 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, including:

- unexpected drilling conditions;

- elevated pressure or irregularities in geologic formations;
- title problems;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, crews, equipment and materials;
- shortages in experienced labor;
- surface access restrictions;
- failure to secure 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, frac crews, production and other equipment and related services. The availability of drilling rigs, frac crews and equipment can vary significantly from region to region at any particular time. Although land drilling rigs and frac crews can be moved from one region to another in response to changes in levels of demand, an undersupply in any region may result in drilling and/or completions delays and higher well costs 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 holes 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 may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews, frac crews, and related equipment and material; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. There can be no assurance that these projects can be successfully developed or that any identified drill sites or budgeted wells will, if drilled, encounter reservoirs of commercially productive oil or gas or that we will be able to complete such wells on a timely basis, or at all. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects or budgeted wells within such project area.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.

The unavailability, high cost or shortage of drilling rigs, frac crews, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of drilling rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig and frac crews also rise with increases in demand. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs and frac crews at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing drilling rigs or frac crews, and such service providers may choose to cease providing services to us. Shortages of drilling rigs, frac crews, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Upon our emergence from bankruptcy, the composition of our Board of Directors changed significantly.

Pursuant to the Plan, the composition of our Board changed significantly. Currently, the Board is made up of four directors, none of which previously served on the Board of the Company. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board and, thus, may have different views on the issues that will determine the future of the Company. As a result, the future strategy and plans of the Company may differ materially from those of the past.

The ability to attract and retain key personnel is critical to the success of our business and may be affected by our emergence from bankruptcy.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of our emergence from bankruptcy, the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on the acreage.

Leases on oil and natural gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change and subject to the availability of capital.

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 our revenues. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly affect our overall credit risk. Recently, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. In 2016, approximately 93 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 under joint venture arrangements. 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 venture 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 volatility in commodity prices and currently depressed commodity environment increases the likelihood that some of these working interest owners may not be able to fulfill their joint venture obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems have led and may lead our partners to continue to attempt to delay the pace of 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.

Estimates of oil and gas reserves and future net cash flows 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, 2016, approximately 47 percent of our estimated proved reserves were proved undeveloped, compared to 25 percent at December 31, 2015. 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 sometime 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.

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.

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. Actual future net cash flows may also be affected by the amount and timing of actual production, availability of financing for capital expenditures necessary to develop our undeveloped reserves, supply and demand for oil and gas, increases or decreases in consumption of oil and gas and changes in governmental regulations or taxation. 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. With all other factors held constant, if commodity prices used in the reserve report were to decrease by 10%, our standardized measure and PV-10 would have decreased from $317.5 million to $234.9 million, respectively. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may record impairments 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 of certain fields because it becomes uneconomic to produce all reserves within 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 significant enough to result in a write-down that would further decrease reported earnings.

The full cost method of accounting for oil and gas properties under GAAP requires that at the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. In addition to revisions to reserves and the impact of lower commodity prices, Ceiling Test write-downs may occur due to increases in estimated operating and development costs and other factors.

During the past several years, we have been required to write-down the value of certain of our oil and gas properties and related assets, including $1.4 billion in 2015 while we applied the the successful efforts method of accounting for oil and gas properties. We could experience additional write-downs in the future while applying the full cost method of accounting for oil and gas properties. While such a charge reflects our ability to recover the carrying value of our investments, it does not impact our cash flows from operating activities.

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

We deliver substantially all of our oil and gas production through pipelines and trucks that we do not own. The marketability of our production depends upon the availability, proximity and capacity of these pipelines and trucks, as well as gathering systems, gas processing facilities and downstream refineries. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells, the reduction in wellhead pricing 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, refine and market our oil and gas.

We rely on third-party service providers to conduct the drilling and completion operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform necessary drilling and completion operations. The ability and availability of third-party service providers to perform such drilling and completion operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, NGLs and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations on a timely basis could delay drilling or completion operations, reduce production from the property or cause other damage to operations, each of which could adversely affect our business, financial condition, results of operations and cash flows.

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

In 2016, other companies operated approximately nine 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.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

We are a relatively small company and therefore may not be able to compete effectively.

Compared to many of our competitors in the oil and gas industry, we are a small company. We face difficulties in competing with larger companies. The costs of doing business in the exploration and production industry, including such costs as those required to explore new oil and natural gas plays, to acquire new acreage, and to develop attractive oil and natural gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, substantially larger staffs and greater financial and operating resources than we have. Our limited size has placed us at a disadvantage with respect to funding our capital and operating costs, and means that we are more vulnerable to commodity price volatility and overall industry cycles, are less able to absorb the burden of changes in laws and regulations, and that poor results in any single exploration, development or production play can have a disproportionately negative impact on us.

We also compete for people, including experienced geologists, geophysicists, engineers and other professionals. Our limited size has placed us at a disadvantage with respect to attracting and retaining management and other professionals with the technical abilities necessary to successfully operate our business.

Our lack of diversification increases the risk of an investment in us and we are vulnerable to risks associated with operating primarily in one major contiguous area.

Our current business is focused primarily in the Eagle Ford in South Texas. Due to the concentrated nature of our business activities, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that are more diversified. In particular, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in which we have an interest that are caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of crude oil or natural gas produced from wells in the Eagle Ford.

The borrowing base under our credit facility may be reduced in the future if commodity prices decline.

The borrowing base under our credit agreement, or Credit Facility, is $128 million as of December 31, 2016. Our borrowing base is redetermined at least twice each year and is scheduled to be redetermined during April 2017. If crude oil, NGL or natural gas prices decline, the borrowing base under the Credit Facility may be reduced. As a result, we may be unable to obtain funding under the Credit Facility. 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 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 Credit Facility has restrictive covenants that could limit our financial flexibility.

The Credit Facility contains 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 Credit Facility is subject to compliance with certain financial covenants, including leverage, interest coverage and current ratios.

The Credit Facility 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.

Our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and gas prices at economically sustainable levels. If the price that we receive for our oil and gas production deteriorates significantly from current levels it could lead to lower revenues, cash flows and earnings, which in turn could lead to a default under certain financial covenants contained in our Credit Facility. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period as the amounts outstanding under our Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings. 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 may 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.

We do not expect to pay dividends in the foreseeable future.

We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, restrictive covenants in certain debt instruments to which we are, or may be a party, may limit our ability to pay dividends or for us to receive dividends from our operating companies, any of which may negatively impact the trading price of our common stock.

Certain provisions of our certificate of incorporation and our bylaws may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Certificate of Incorporation and our Bylaws may have the effect of delaying or preventing changes in control if our Board determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Certificate of Incorporation and Bylaws include, among other things, those that:

- authorize our Board to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;
- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings; and
- limit the persons who may call special meetings of stockholders.

While these provisions have the effect of encouraging persons seeking to acquire control of the Company to negotiate with our Board, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors. These provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board, which is responsible for appointing the members of our management.

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 Part I, Item 1, “Business - Government Regulation and Environmental Matters.”

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-related materials from the wellbore to allow production to begin;
- environmental hazards such as natural gas leaks, oil or produced water spills and discharges of toxic gases; and
- natural disasters and other adverse weather conditions, terrorism, vandalism and physical, electronic and cyber security breaches.

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 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:

- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of GHGs;
- 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 will 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.

Access to water to drill and conduct hydraulic fracturing may not be available if water sources become scarce.

The availability of water is crucial to conduct hydraulic fracturing. A significant amount of water is necessary for drilling and completing each well with hydraulic fracturing. In the past, Texas has experienced severe droughts that have limited the water supplies that are necessary to conduct hydraulic fracturing. Although we have taken measures to secure our water supply, we can make no assurances that sufficient water resources will be available in the short or long term to carry out our current activities.

Laws and regulations restricting emissions of greenhouse gases could force us to incur increased capital and operating costs and could have a material adverse effect on our financial condition, results of operations and cash flows.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. For example, the EPA issued rules restricting methane emissions from hydraulically fractured and refractured gas wells, compressors, pneumatic controls, storage vessels, and natural gas processing plants. For more information on GHG regulation, see Part I, Item 1, "Business - Government Regulation and Environmental Matters."

In addition, 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, droughts, floods and other climatic events. If any such events were to occur, they could have an adverse effect on our financial condition, results of operations and cash flows. For a more complete discussion of environmental laws and regulations intended to address climate change and their impact on our business and operations, see Part I, Item 1, "Business - Environmental Regulation - Climate Change."

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

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to complete wells. The EPA released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of the EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but did not pass, legislation to amend the Safe Drinking Water Act, or SDWA, to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. The EPA has issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority.

In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans/moratoria on drilling that effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. Texas has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. Moreover, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, Texas regulators have asserted regulatory authority to limit injection activities in certain wells in an effort to reduce seismic activity. A 2015 U.S. Geological Survey report identified areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction.

The adoption of new laws or regulations imposing reporting or operational obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

Restrictions on drilling activities intended to protect certain species of wildlife or their habitat may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Various federal and state statutes prohibit certain actions that harm endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act, CERCLA and the OPA. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, may seek criminal penalties.

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 three 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, 2016, 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.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including 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, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U. S. production activities and (iv) 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 and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be adversely affected.

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

The oil and gas industry is increasingly 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 insufficient, 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

None.

Item 2 Properties

As of December 31, 2016, our primary oil and gas assets were located in Gonzales and Lavaca Counties in South Texas and Washita and Custer Counties in Western Oklahoma.

Facilities

All of our office facilities are leased and 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. As is customary in the oil and gas industry, however, we make a cursory review of title when we acquire farmout acreage or 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	PV10 [1]
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)	$ in millions	$ in millions
2016 (Successor)						
Developed						
Producing	17.5	4.3	24.8	25.9		
Non-producing	0.2	0.1	0.1	0.3		
	17.7	4.4	24.9	26.2		
Undeveloped	18.9	2.4	11.8	23.3		
	36.6	6.8	36.7	49.5	$ 317.5	$ 317.5
Price measurement used [2]	$42.75/Bbl	$12.33/Bbl	$2.48/MMBtu			
2015 (Predecessor)						
Developed						
Producing	19.6	6.1	36.8	31.8		
Non-producing	0.6	0.1	0.4	0.8		
	20.2	6.2	37.2	32.6		
Undeveloped	9.3	1.0	5.0	11.1		
	29.5	7.2	42.2	43.7	$ 323.3	$ 323.3
Price measurement used [2]	$50.28/Bbl	$14.44/Bbl	$2.70/MMBtu			
2014 (Predecessor)						
Developed						
Producing	21.8	7.4	77.9	42.1		
Non-producing	0.3	0.7	16.6	3.8		
	22.1	8.1	94.5	45.9		
Undeveloped	47.0	11.1	64.7	68.9		
	69.0	19.2	159.2	114.8	$ 1,182.4	$ 1,472.5
Price measurement used [2]	$94.99/Bbl	$25.49/Bbl	$4.35/MMBtu			

[1] PV10 represents a non-GAAP measure that is most directly comparable to the Standardized Measure as defined in GAAP. The Standardized Measure represents the discounted future net cash flows from our proved reserves after future income taxes discounted at 10% in accordance with SEC criteria. PV10 represents the Standardized Measure without regard to income taxes. Our Standardized Measures for 2016 and 2015 did not include any income tax effect. Accordingly, our PV10 and Standardized Measure values are equivalent as of those dates. We believe that PV10 is a meaningful supplemental disclosure to the Standardized Measure as the the PV10 concept is widely used within the industry and by the financial and investment community to evaluate the proved reserves on a comparable basis across companies without regard to the individual owner's unique income tax position. We utilize PV10 to evaluate the potential return on investment in our oil and gas properties as well as evaluating properties for potential purchases and sales.

[2] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu. The representative prices of crude oil and natural gas, as adjusted for basis differentials and product quality, were as follows: crude oil - $40.97, $45.78 and $92.91 each per Bbl, NGLs - $11.82, $13.15 and $25.09 each per Bbl and natural gas - $2.40, $2.59 and $4.32 each per MMBtu, for December 31, 2016, 2015 and 2014, respectively. NGL prices were estimated as a percentage of the base crude oil price.

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, 2016:

Region	Proved Reserves	% of Total Proved Reserves	% Proved Developed
	(MMBOE)		
South Texas	47.0	95%	51%
Mid-Continent	2.5	5%	100%
	49.5	100%	53%

A discussion and analysis of the changes in our total proved reserves is provided in the Supplemental Information on Oil and Gas Producing Activities included in Part II, Item 8, "Financial Statements and Supplementary Data."

Proved Undeveloped Reserves

The proved undeveloped reserves included in our reserve estimates relate to wells that are forecasted to be drilled within the next three years. The following table sets forth the changes in our proved undeveloped reserves, all of which are located in the Eagle Ford in South Texas, during the year ended December 31, 2016:

	Crude Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Oil Equivalents (MMBOE)
Proved undeveloped reserves at beginning of year (Predecessor)	9.3	1.0	5.0	11.1
Revisions of previous estimates	(1.3)	—	—	(1.3)
Extensions and discoveries	11.5	1.5	7.2	14.2
Conversion to proved developed reserves	(0.6)	(0.1)	(0.4)	(0.7)
Proved undeveloped reserves at end of year (Successor)	18.9	2.4	11.8	23.3

In 2016, our proved undeveloped reserves increased by 12.2 MMBOE. We experienced negative revisions of 1.3 MMBOE due to the loss of certain locations resulting from changes in the timing of our development plans and lower EURs due primarily to lower commodity prices compared to year-end 2015. Extensions and discoveries of 14.2 MMBOE were attributable primarily to the resumption of our development plans in the Eagle Ford. In addition, we converted 0.7 MMBOE from proved undeveloped to proved developed reserves in the Eagle Ford. During 2016, we incurred capital expenditures of $6.8 million in connection with the conversion of proved undeveloped reserves to proved developed reserves. The conversion of these reserves occurred in the first quarter of 2016 prior to the termination of our drilling program which preceded our bankruptcy filing. Accordingly, our conversion rate of proved undeveloped reserves as of beginning of the year is not representative as we did not resume our drilling program until November 2016.

Preparation of Reserves Estimates and Internal Controls

The proved reserve estimates were prepared by DeGolyer and MacNaughton, 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 included in Part II, Item 8, "Financial Statements and Supplementary Data" and the report of DeGolyer and MacNaughton, Inc., dated February 9, 2017, 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, 2016 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 DeGolyer and MacNaughton, Inc. Our Vice President, Operations & Engineering has over 30 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 Part I, Item 1A, "Risk Factors."

Qualifications of Third Party Petroleum Engineers

The technical person primarily responsible for review of our reserve estimates at DeGolyer and MacNaughton, 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. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; 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

In the tables that follow, we have presented our former operations in the Haynesville Shale and Cotton Valley in East Texas and Selma Chalk in Mississippi, which were sold in 2015 and 2014 as "Divested properties." The sales of those operations represented complete divestitures and we have retained no interests therein. In addition, we sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015. The production associated with these former properties is also included within "Divested properties." Our remaining operations are represented in the Eagle Ford in South Texas, the Granite Wash in Oklahoma and relatively minor operations, which we terminated in August 2016, in the Marcellus Shale in Pennsylvania.

Oil and Gas Production by Region

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

	Total Production			
	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
Region	**2016**	**2016**	**2015**	**2014**
	(MBOE)	(MBOE)		
South Texas	937	3,071	6,903	5,817
Mid-Continent and other [1]	103	276	460	743
Divested properties [2]	—	—	560	1,375
	1,040	3,346	7,923	7,934

	Average Daily Production			
	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
Region	**2016**	**2016**	**2015**	**2014**
	(BOEPD)	(BOEPD)		
South Texas	8,518	11,996	18,912	15,937
Mid-Continent and other [1]	936	1,082	1,260	2,036
Divested properties [2]	—	—	2,151	3,765
	9,454	13,078	22,323	21,738

[1] Includes total production and average daily production of approximately 10 MBOE (48 BOEPD), 22 MBOE (60 BOEPD) and 24 MBOE (66 BOEPD) for 2016, 2015 and 2014, respectively, attributable to our three active Marcellus Shale wells.

[2] We sold all of our properties in the Haynesville Shale and Cotton Valley in East Texas in August 2015, which represented total production and average daily production of approximately 449 MBOE (1,847 BOEPD) and 844 MBOE (2,311 BOEPD) in 2015 and 2014, respectively. We sold all of our properties in the Selma Chalk in Mississippi in July 2014, which represented annual production and average daily production of approximately 412 MBOE (1,946 BOEPD) in 2014. We sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015, which represented total production and average daily production of approximately 111 MBOE (364 BOEPD) and 118 MBOE (325 BOEPD) in 2015 and 2014, respectively.

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:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	**2016**	**2015**	**2014**
Average prices:				
Crude oil ($ per Bbl)	$ 46.63	$ 35.21	$ 44.81	$ 90.50
NGLs ($ per Bbl)	$ 16.51	$ 11.38	$ 12.24	$ 31.14
Natural gas ($ per Mcf)	$ 2.81	$ 2.06	$ 2.62	$ 4.44
Aggregate ($ per BOE)	$ 37.17	$ 27.99	$ 33.19	$ 64.64
Average production and lifting cost ($ per BOE):				
Lease operating	$ 5.13	$ 4.67	$ 5.36	$ 6.09
Gathering processing and transportation	2.93	3.96	3.01	2.31
	$ 8.06	$ 8.63	$ 8.37	$ 8.40

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily oil reserves, represented approximately 95 percent of our total equivalent proved reserves as of December 31, 2016.

The following table sets forth certain information with respect to this field for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Production: [1]				
Crude oil (MBbl)	695	2,265	4,733	4,369
NGLs (MBbl)	130	449	1,169	771
Natural gas (MMcf)	674	2,141	6,011	4,063
Total (MBOE)	937	3,071	6,903	5,817
Percent of total company production	90 %	92 %	87%	73%
Average prices:				
Crude oil ($ per Bbl)	$ 46.73	$ 35.24	$ 44.73	$ 90.70
NGLs ($ per Bbl)	$ 14.82	$ 10.34	$ 11.03	$ 25.24
Natural gas ($ per Mcf)	$ 2.79	$ 2.05	$ 2.64	$ 4.20
Aggregate ($ per BOE)	$ 38.71	$ 28.94	$ 34.84	$ 74.40
Average production and lifting cost ($ per BOE): [2]				
Lease operating	$ 5.39	$ 4.58	$ 5.04	$ 5.36
Gathering processing and transportation	2.58	3.50	2.66	1.76
	$ 7.97	$ 8.08	$ 7.70	$ 7.12

[1] Excludes production from certain non-core Eagle Ford properties that we sold in October 2015.

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

Drilling and Other Exploratory and Development Activities

The following table sets forth the gross and net development wells that we drilled, all of which were in the Eagle Ford in South Texas, during the years ended December 31, 2016, 2015 and 2014, respectively, and wells that were in progress at the end of each year. There were no exploratory wells drilled in any of the years presented. The number of wells drilled refers to the number of wells completed at any time during the year, regardless of when drilling was initiated.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive	5	2.9	61	38.6	83	50.8
Dry well	—	—	—	—	1	0.8
Under evaluation	—	—	—	—	—	—
Total	5	2.9	61	38.6	84	51.6
Wells in progress at end of year [1]	5	2.6	4	2.3	28	14.3

[1] Includes three gross (1.4 net) wells completing, one gross (0.6 net) well waiting on completion and one gross (0.6 net) well being drilled as of December 31, 2016.

Present Activities

As of December 31, 2016, we had five gross (2.6 net) wells in progress, all of which were located in the Eagle Ford in South Texas. As of March 15, 2017, all of these 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. We have commitments to provide minimum deliveries of crude oil of 8,000 BOPD (gross) in our South Texas region for a period of 15 years under a gathering agreement with Republic Midstream, LLC, or Republic Midstream. Our production and reserves are currently sufficient to fulfill the current 8,000 BOPD delivery commitment under those agreements. In 2016 following the suspension of our drilling program, we incurred deficiencies of $0.4 million as a result of our inability to satisfy the 15,000 BOPD delivery commitment under such agreements prior to their August 2016 amendments.

Productive Wells

The following table sets forth by region the productive wells in which we had a working interest as of December 31, 2016:

	Primarily Oil		Primarily Natural Gas		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas [1]	334	212.2	—	—	334	212.2
Mid-Continent	2	1.6	95	41.1	97	42.7
	336	213.8	95	41.1	431	254.9

Of the total wells presented in the table above, we are the operator of 335 gross (304 oil and 31 gas) and 220.6 net (201.3 oil and 19.3 gas) wells. In addition to the above working interest wells, we own royalty interests in 12 gross wells.

Acreage

The following table sets forth by region our developed and undeveloped acreage as of December 31, 2016 (in thousands):

	Developed		Undeveloped		Total	
Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
South Texas	74.5	48.2	27.5	22.3	102.0	70.5
Mid-Continent and other	15.6	7.4	12.1	11.9	27.7	19.3
	90.1	55.6	39.6	34.2	129.7	89.8

The primary terms of our leases generally range from three to five years and we do not have any concessions. All of our acreage in the Granite Wash in Oklahoma and the Marcellus Shale in Pennsylvania, both of which are included in the Mid-Continent and other region, is HBP. As of December 31, 2016, 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:

Region	**2017**	**2018**	**2019**	**Thereafter**
South Texas	17.7	3.5	0.0	1.1
Mid-Continent and other	2.5	0.0	9.4	0.0

We plan to allow approximately 20,500 gross (17,700 net) acres of undeveloped acreage in the Eagle Ford expire as scheduled in 2017 as they are not considered core to our current development plans. Accordingly, 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

On May 12, 2016, we and the Chapter 11 Subsidiaries filed voluntary petitions (*In re Penn Virginia Corporation, et al. Case No. 16-32395*) seeking relief under the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Virginia.

On August 11, 2016, the Bankruptcy Court confirmed our Plan, and we subsequently emerged from bankruptcy on September 12, 2016. See Note 4 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," for a more detailed discussion of our bankruptcy proceedings.

On February 7, 2017, a former shareholder of the Company filed a motion in the Bankruptcy Court requesting that the Bankruptcy Court set aside its prior order confirming the Plan, previously confirmed on August 11, 2016. This motion currently has no impact on the order confirming the Plan. We believe the motion is without merit and will defend confirmation of the Plan.

See Note 16 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." 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.

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

In connection with our reorganization and emergence from bankruptcy, all of our Predecessor common stock, formerly traded under the symbol "PVA," was canceled, extinguished and discharged. On November 15, 2016, our Successor common stock, or New Common Stock, was listed on the OTCQX U.S. Premier Market under the symbol "PVAC." Prior to such time, there was no established trading market for the New Common Stock. On December 28, 2016, the New Common Stock was listed and began trading on the Nasdaq under the symbol "PVAC."

The market data below represents the high and low sales prices (composite transactions) of the New Common Stock since November 15, 2016:

	Sales Price	
Quarter Ended	**High**	**Low**
December 31, 2016	$ 50.00	$ 34.75

Equity Holders

As of March 1, 2017, there were 59 record holders and 1,702 beneficial owners (held in street name) of our New Common Stock.

Dividends

We have not paid nor do we intend in the foreseeable future to pay any cash dividends on the New Common Stock. Furthermore, we are restricted from paying dividends under the Credit Facility.

Securities Authorized for Issuance Under Equity Compensation Plans

See Part III, Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters" and Note 18 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for information regarding shares of New Common Stock authorized for issuance under our stock compensation plans.

Recent Sales of Unregistered Securities

Pursuant to the Plan, a total of $50 million of proceeds were received on the Effective Date from a rights offering conducted in connection with the Plan, or the Rights Offering, resulting in the issuance of 7,633,588 shares of New Common Stock to holders of claims arising under our 7.25% Senior Notes due 2019, or the 2019 Senior Notes, and 8.50% Senior Notes due 2020, or the 2020 Senior Notes, and, together with the 2019 Senior Notes, the Senior Notes, certain holders of general unsecured claims and to the parties, or Backstop Parties, supporting a backstop commitment agreement, or the Backstop Commitment Agreement. The shares of New Common Stock issued to participants in the Rights Offering and to the Backstop Commitment Parties were issued under the exemption from the registration requirements of the Securities Act provided by Section 4(a)(2) thereof.

Issuer Purchases of Equity Securities

We did not repurchase any shares of our New Common Stock in the fourth quarter of 2016.

Item 6 Selected Financial Data

The following selected historical financial and operating information was derived from our Consolidated Financial Statements. The selected financial data should be read in conjunction with Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our Consolidated Financial Statements and the accompanying Notes and Supplementary Data in Part II, Item 8, "Financial Statements and Supplementary Data."

	Successor	Predecessor				
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,			
	2016	2016	2015	2014	2013	2012
		(in thousands, except per share amounts)				
Statements of Operations and Other Data:						
Revenues	$ 39,003	$ 94,310	$ 305,298	$ 636,773	$ 431,468	$ 317,149
Operating income (loss)[1]	$ 11,391	$ (20,856)	$ (1,565,041)	$ (615,985)	$ (92,046)	$ (147,091)
Net income (loss) [2]	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)	$ (143,070)	$ (104,589)
Preferred stock dividends [3]	$ —	$ 5,972	$ 22,789	$ 17,148	$ 6,900	$ 1,687
Income (loss) attributable to common shareholders [2]	$ (5,296)	$ 1,048,630	$ (1,605,750)	$ (430,996)	$ (149,970)	$ (106,276)
Income (loss) per common share, basic	$ (0.35)	$ 11.91	$ (21.81)	$ (6.26)	$ (2.41)	$ (2.22)
Income (loss) per common share, diluted	$ (0.35)	$ 8.50	$ (21.81)	$ (6.26)	$ (2.41)	$ (2.22)
Weighted-average shares outstanding:						
Basic	14,992	88,013	73,639	68,887	62,335	47,919
Diluted	14,992	124,087	73,639	68,887	62,335	47,919
Dividends declared per share	$ —	$ —	$ —	$ —	$ —	$ 0.113
Cash provided by operating activities	$ 30,774	$ 30,247	$ 169,303	$ 282,724	$ 261,512	$ 241,458
Cash paid for capital expenditures	$ 4,812	$ 15,359	$ 364,844	$ 774,139	$ 504,203	$ 370,907
Total production (MBOE)	1,040	3,346	7,923	7,934	6,824	6,513
	December 31,	September 12,	December 31,			
Balance Sheet and Other Data:	2016	2016	2015	2014	2013	2012
Property and equipment, net	$ 247,473	$ 253,510	$ 344,395	$ 1,825,098	$ 2,237,304	$ 1,723,359
Total assets	$ 291,686	$ 333,974	$ 517,725	$ 2,201,810	$ 2,472,830	$ 1,831,733
Total debt	$ 25,000	$ 75,350	$ 1,224,383	$ 1,085,429	$ 1,252,808	$ 583,503
Shareholders' equity (deficit)	$ 185,548	$ 190,895	$ (915,121)	$ 675,817	$ 788,804	$ 895,116
Actual shares outstanding at period-end	14,992	14,992	81,253	71,569	65,307	55,117
Proved reserves as of December 31, (MMBOE)	49		44	115	136	113

[1] Operating loss for 2015, 2014, 2013 and 2012 included impairment charges of $1.4 billion, $791.8 million, $132.2 million and $104.5 million, respectively.

[2] Net income and Income attributable to common shareholders for the period of January 1 through September 12, 2016 includes reorganization items attributable to our bankruptcy proceedings of $1.145 billion.

[3] Excludes inducements paid for the conversion of preferred stock of $4.3 million in 2014.

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 Part II, Item 8, "Financial Statements and Supplementary Data." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure and the number of decimal places presented and rounding, 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 onshore exploration, development and production of crude oil, NGLs and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale field, or the Eagle Ford, in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash. In August 2016, we terminated our remaining operations in the Marcellus Shale in Pennsylvania and are currently in the process of remediating the sites of our former wells in that region.

As discussed in further detail in Note 5 to our Consolidated Financial Statements, we have adopted and applied Fresh Start Accounting as a result of our emergence from bankruptcy. Accordingly, our Consolidated Financial Statements and Notes after September 12, 2016 are not comparable to the Consolidated Financial Statements and Notes prior to that date. To facilitate our discussion and analysis of our financial condition and results of operations herein, we refer to the reorganized company as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. Furthermore, our presentations herein include a "black line" division to delineate the lack of comparability between the Predecessor and Successor. In order to facilitate our discussion herein, we have addressed the Successor and Predecessor periods discretely and have provided comparative analysis, to the extent practical, where appropriate. In addition, and as referenced in Note 2 to the Consolidated Financial Statements, we have adopted the full cost method of accounting for our oil and gas properties effective with our adoption of Fresh Start Accounting. Accordingly, our results of operations and financial position for the Successor periods will be substantially different from our historic trends.

While crude oil prices have recovered somewhat from recent historic low levels of less than $30 per Bbl in February 2016 to approximately $55 per Bbl by the end of 2016, they remain depressed due to domestic and global supply and demand factors compared to the period of 2009 through 2014 when we initially began our expansion into the Eagle Ford. Similarly, the costs for drilling, completion and general oilfield products and services have declined as the industry experienced reduced demand for such products and services. While many of these costs remain at low levels, it is anticipated that certain costs, including those for drilling and completion services, will rise as industry drilling activity continues to recover and expand. Among other factors expected to drive this increase is the consolidation of certain service providers as financially weaker vendors were forced out of the market resulting in fewer choices for upstream producers.

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

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Total production (MBOE)	1,040	3,346	7,923	7,934
Average daily production (BOEPD)	9,454	13,081	22,323	21,738
Crude oil production (MBbl)	711	2,311	4,923	4,644
Crude oil production as a percent of total	68 %	69 %	62%	59%
Product revenues	$ 38,654	$ 93,649	$ 262,980	$ 512,882
Crude oil revenues	$ 33,157	$ 81,377	$ 220,596	$ 420,286
Crude oil revenues as a percent of total	86 %	87 %	84%	82%
Realized prices:				
Crude oil ($/Bbl)	$ 46.63	$ 35.21	$ 44.81	$ 90.50
NGL ($/Bbl)	$ 16.51	$ 11.38	$ 12.24	$ 31.14
Natural gas ($/Mcf)	$ 2.81	$ 2.06	$ 2.62	$ 4.44
Aggregate ($/BOE)	$ 37.17	$ 27.99	$ 33.19	$ 64.64
Production and lifting costs ($/BOE):				
Lease operating	$ 5.13	$ 4.67	$ 5.36	$ 6.09
Gathering, processing and transportation	$ 2.93	$ 3.96	$ 3.01	$ 2.31
Production and ad valorem taxes ($/BOE)	$ 2.40	$ 1.04	$ 2.06	$ 3.53
General and administrative ($/BOE) [1]	$ 4.89	$ 4.66	$ 4.08	$ 4.93
Depreciation, depletion and amortization ($/BOE)	$ 11.20	$ 10.04	$ 42.22	$ 37.85
Cash provided by operating activities	$ 30,774	$ 30,247	$ 169,303	$ 282,724
Cash paid for capital expenditures	$ 4,812	$ 15,359	$ 364,844	$ 774,139
Cash and cash equivalents at end of period	$ 6,761	$ 31,414	$ 11,955	$ 6,252
Debt outstanding, net of discount, at end of period	$ 25,000	$ 75,350	$ 1,245,000	$ 1,110,000
Credit available under credit facility at end of period [2]	$ 102,232	$ 51,883	$ —	$ 413,196
Proved reserves at the end of the period (MMBOE)	49		44	115
Net development wells drilled and completed	—	2.9	38.6	51.6

[1] Excludes equity-classified share-based compensation, liability-classified share-based compensation and significant special charges, including strategic and financial advisory costs prior to our bankruptcy filing, among others as described in the discussion of *"Results of Operations - General and Administrative Expenses,"* of $6.98, $1.39 and $1.25 for the Predecessor period in 2016 and the years ended December 31, 2015 and 2014, respectively.

[2] As of December 31, 2015, we were unable to draw on our pre-petition credit facility, or RBL.

Key Developments

The following general business developments and corporate actions had or may have a significant impact on our results of operations, financial position and cash flows:

Bankruptcy Proceedings

On the Petition Date, we and the Chapter 11 Subsidiaries, filed voluntary petitions (*In re Penn Virginia Corporation, et al, Case No. 16-32395*) seeking relief under the Bankruptcy Code in the Bankruptcy Court. On the Confirmation Date, the Bankruptcy Court confirmed our Plan and we subsequently emerged from bankruptcy on the Effective Date.

Debtors-In-Possession. From the Petition Date through the Effective Date, we and the Chapter 11 Subsidiaries operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted all "first day" motions filed by us and the Chapter 11 Subsidiaries, which were designed primarily to minimize the impact of the bankruptcy proceedings on our normal day-to-day operations, our customers, regulatory agencies, including taxing authorities, and employees. As a result, we were able to conduct normal business activities and pay all associated obligations for the post-petition period and we were also authorized to pay and have paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, amounts due to taxing authorities for production and other related taxes and funds belonging to third parties, including royalty and working interest holders.

Pre-Petition Agreements. Immediately prior to the Petition Date, the holders, or the Ad Hoc Committee, of approximately 86 percent of the $1,075 million principal amount of the Senior Notes agreed to a restructuring support agreement, or the RSA, that set forth the general framework of the Plan and the timeline for the bankruptcy proceedings. In addition, we entered into the Backstop Commitment Agreement pursuant to which the Backstop Parties committed to provide a $50 million commitment to backstop the Rights Offering.

Plan of Reorganization. Pursuant to the terms of the Plan, which was supported by us, the holders of 100 percent of the claims attributable to our RBL, or the RBL Lenders, the Ad Hoc Committee and the Official Committee of Unsecured Claimholders, or the UCC, the following transactions were completed subsequent to the Confirmation Date and prior to or at the Effective Date:

- the approximately $1,122 million of indebtedness, including accrued interest, attributable to our Senior Notes and certain other unsecured claims were exchanged for 6,069,074 shares representing 41 percent of the New Common Stock;
- a total of $50 million of proceeds were received on the Effective Date from the Rights Offering resulting in the issuance of 7,633,588 shares representing 51 percent of New Common Stock to holders of claims arising under the Senior Notes, certain holders of general unsecured claims and to the Backstop Parties;
- the Backstop Parties received a backstop fee comprised of 472,902 shares representing three percent of New Common Stock;
- an additional 816,454 shares representing five percent of New Common Stock were authorized for disputed general unsecured claims and non-accredited investor holders of the Senior Notes and subsequently, 749,600 shares of New Common Stock were reserved for issuance under a new management incentive plan;
- on the Effective Date, we entered into a shareholders agreement and a registration rights agreement and amended our articles of incorporation and bylaws for the authorization of the New Common Stock and to provide customary registration rights thereunder, among other corporate governance actions;
- holders of claims arising under the RBL were paid in full from cash on hand, $75.4 million from borrowings under the Credit Facility (see below, the discussion of *"Liquidity"* that follows and Note 11 to the Consolidated Financial Statements) and proceeds from the Rights Offering;
- the debtor-in-possession credit facility, or DIP Facility, under which there were no outstanding borrowings at any time from the Petition Date through the Effective Date, was canceled and less than $0.1 million in fees were paid in full in cash;
- certain other priority claims were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditor claim-holders;
- a cash reserve of $2.7 million was established for certain other secured, priority or convenience claims pending resolution as of the Effective Date;
- an escrow account for professional service fees attributable to our advisers and those of the UCC was funded by us with cash of $14.6 million, and we paid $7.2 million for professional fees and expenses on behalf of the RBL Lenders, the Ad Hoc Committee and the indenture trustee for the Senior Notes;
- on the Effective Date, our previous interim Chief Executive Officer, Edward B. Cloues, resigned and each member of our board of directors resigned and was replaced by new board members: Darin G. Holderness, CPA, Marc McCarthy and Harry Quarls and, in October 2016 by Jerry R. Schuyler;
- our Predecessor preferred stock and common stock was canceled, extinguished and discharged; and
- all of our Predecessor share-based compensation plans and supplemental employee retirement plan, or the SERP, entitlements were canceled.

While our emergence from bankruptcy is effectively complete, certain administrative and claims resolution activities will continue under the authority of the Bankruptcy Court until complete. As of March 10, 2017, certain claims, including secured tax and other priority, administrative and convenience claims were still in the process of resolution. While most of these matters are unsecured claims for which shares of New Common Stock have been allocated, certain of these matters must be settled with cash payments. As of December 31, 2016, we had $3.9 million reserved for outstanding claims to be potentially settled in cash. This reserve is included as a component of accounts payable and accrued liabilities on our Consolidated Balance Sheet.

New Credit Facility

We entered into the Credit Facility on the Effective Date. The Credit Facility provides us with up to $200 million in borrowing commitments and the initial borrowing base under the Credit Facility is $128 million. Please read "Financial Condition - *Capitalization: Revolving Credit Facility*," which follows.

Production, Capital and Development Plans

Total production for the quarter and year ended December 31, 2016 (for the combined Predecessor and Successor periods) was 857 MBOE and 4,386 MBOE, or 9,316 BOEPD and 11,983 BOEPD, with 68 percent and 69 percent of production comprised of oil, 16 percent and 16 percent comprised of NGLs and 16 percent and 15 percent comprised on natural gas. For the year, 1,040 MBOE was attributable to the Successor and 3,346 MBOE was attributable to the Predecessor. Production from our Eagle Ford operations during the quarter and annual periods was 773 MBOE and 4,008 MBOE or 8,402 BOEPD and 10,951 BOEPD, 937 MBOE of which was attributable to the Successor and 3,071 MBOE of which was attributable to the Predecessor. Approximately 74 percent and 67 percent of our Eagle Ford production for the combined periods was from crude oil, 14 percent and 13 percent was from NGLs and 12 percent and 20 percent was from natural gas. Production from Eagle Ford operations was approximately 90 percent and 91 percent of total Company production during these combined periods and was derived from 302 operated and 32 outside-operated legacy wells.

We restarted our Eagle Ford drilling program in November 2016 by drilling the third well on the three-well Sable pad and have since drilled seven additional wells with six wells completed through March 10, 2017. The Sable wells were turned to sales in February 2017 and have been producing with 24-hour IP rates for the pad reaching 6,540 BOEPD (6,156 BOPD, or 94 percent oil). The 30-day IP rate for the Sable pad was 2,776 BOEPD (2,614 BOPD, or 94 percent oil). We recently completed the three-well Axis pad at the northern extent of our acreage, which generated a combined 24-hour IP rate of 6,341 BOEPD (5,908 BOPD, or 93 percent oil). The three-well Axis pad was turned to sales at the beginning of March 2017. We also recently finished drilling the four-well Kudu pad and are preparing to commence completion operations. Our first rig has moved to the Zebra pad to drill the first of three wells. Our second rig recently spudded the Lager 3H.

Capital expenditures for 2017 are expected to total between $120 and $140 million with approximately 90 percent of capital being directed to drilling and completions on our Eagle Ford assets. The capital plan provides for drilling 41 to 44 gross wells (19 to 22 net wells) with 31 to 34 gross wells (16 to 19 net wells) turned to sales. We plan to fund our 2017 capital expenditures with cash from operating activities and borrowings under the Credit Facility.

As of March 10, 2017, we had approximately 54,000 net core Eagle Ford acres largely held by production.

Amended Gathering and Transportation Agreements

In August 2016, the Bankruptcy Court approved a settlement with Republic Midstream and Republic Midstream Marketing, LLC, or Republic Marketing, and, together with Republic Midstream, Republic, and authorized the assumption of certain amended agreements with Republic, or the Amended Agreements. We paid Republic $0.3 million in connection with the settlement which is included in “Reorganization items, net” in our Consolidated Statements of Operations.

Under the terms of the Amended Agreements, Republic is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford, or Dedication Area, via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party. The amended gathering agreement reduced our minimum volume commitment from 15,000 to 8,000 barrels of oil per day. The term of the amended gathering agreement runs through 2041, with the term of the minimum volume commitment extended from 10 to 15 years.

Under the amended marketing agreement, we have a 10-year commitment to sell 8,000 barrels per day of crude oil to Republic, or any third party, utilizing Republic Marketing’s capacity on a certain downstream interstate pipeline.

Cost Reduction Initiatives

We took significant measures in 2016 to significantly reduce our drilling, operating and support costs. In conjunction with our reorganization through bankruptcy, we renegotiated a number of contracts with vendors and service providers to bring costs in line with current market conditions.

Other initiatives include reductions in force and, at the corporate level, we have also undertaken significant staff reductions. In connection with efforts to reduce our administrative costs, we took certain actions to reduce our total employee headcount. In 2016, we reduced our total employee headcount by 53 employees. We paid a total of $2.1 million, including $1.4 million in severance and termination benefits and $0.7 million in retention bonuses during the year ended December 31, 2016.

Commodity Hedging Program

Shortly after the Petition Date, we hedged a substantial portion of our future crude oil production through the end of 2019 in accordance with the Plan. Our weighted-average hedge prices are approximately $48.62 per barrel for 2017, $49.12 per barrel for 2018 and $49.90 per barrel for 2019. We are currently unhedged with respect to natural gas production.

Stock Listing

In connection with our reorganization and emergence from bankruptcy, all of our Predecessor common stock that formally traded under the symbol “PVA,” was canceled, extinguished and discharged. On November 15, 2016, our New Common Stock was listed on the OTCQX U.S. Premier market under the symbol “PVAC.” Prior to such time, there was no established trading market for the New Common Stock. On December 28, 2016, the New Common Stock was listed and began trading on the Nasdaq under the symbol “PVAC.”

Financial Condition

Liquidity

Our primary sources of liquidity include our cash on hand, cash provided by operating activities and borrowings under the Credit Facility. The Credit Facility provides us with up to $200 million in borrowing commitments. The initial borrowing base under the Credit Facility is $128 million. As of March 10, 2016, we had outstanding borrowings and letters of credit of $30 million $0.8 million, respectively, resulting in $97.2 million of availability under the Credit Facility .

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for our crude oil, NGL 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 other factors. The level of our hedging activity and duration of the instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

In order to mitigate this volatility, we entered into a series of new derivatives contracts in May 2016 and hedged a substantial portion of our future crude oil production through the end of 2019. Our weighted-average hedge prices are $48.62 per barrel for 2017, $49.12 per barrel for 2018 and $49.90 per barrel for 2019. Our natural gas hedges expired in 2015 and we currently are and expect to remain unhedged with respect to natural gas as well as NGL production.

Capital Resources

Under our business plan for 2017, we currently anticipate capital expenditures to total between $120 million and $140 million with approximately 90 percent of capital being directed to drilling and completions on our Eagle Ford acreage. We plan to fund our 2017 capital spending with cash from operating activities and borrowings under the Credit Facility. Based upon current price and production expectations for 2017, we believe that our cash from operating activities and borrowings under our Credit Facility will be sufficient to fund our operations through year-end 2017; however, future cash flows are subject to a number of variables and significant additional capital expenditures may be required to more fully develop our properties. Our 2017 capital expenditure budget does not allocate any funds for acquisitions. For a detailed analysis of our historical capital expenditures, see the "*Cash Flows*" discussion that follows.

Cash on Hand and Cash From Operating Activities. As of March 10, 2017, we had approximately $6 million of cash on hand. For additional information and an analysis of our historical cash from operating activities, see the "*Cash Flows*" discussion that follows. In addition and as discussed further above, we have actively managed our exposure to commodity price fluctuations, which impacts our cash from operating activities, by hedging the commodity price risk for a portion of our expected production.

Credit Facility Borrowings. We initially borrowed $75.4 million under the Credit Facility on the Effective Date. Since that time we have paid down $45.4 million, net of new borrowings through March 10, 2017. For additional information regarding the terms and covenants under the Credit Facility, see the "*Capitalization*" discussion that follows.

The following table summarizes our borrowing activity under the Credit Facility for the periods presented:

	Borrowings Outstanding		
	Weighted-Average	Maximum	Weighted-Average Rate
Successor period for the three months ended December 31, 2016	$ 39,335	$ 54,350	3.7430%
Successor period from September 12, 2016 to December 31, 2016	$ 44,616	$ 75,350	3.8940%

Proceeds from Sales of Assets. We continually evaluate potential sales of non-core assets, including certain oil and gas properties and non-strategic undeveloped acreage, among others. For additional information and an analysis of our historical proceeds from sales of assets, 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 may consider capital market transactions, including the offering of debt and equity securities.

Cash Flows

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

	Successor	Predecessor	
	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Cash flows from operating activities			
Operating cash flows, net of working capital changes	$ 31,068	$ 34,731	$ 130,293
Commodity derivative settlements received, net:			
Crude oil	384	48,008	137,488
Natural gas	—	—	681
Interest payments, net of amounts capitalized	(598)	(4,148)	(86,226)
Income taxes received, net	7	35	714
Drilling rig termination costs paid	—	—	(6,636)
Strategic, financial and bankruptcy-related advisory fees and costs paid	(648)	(46,606)	(3,693)
Return of remaining professional fee escrow	756	—	—
Restructuring and exit costs paid	(195)	(1,773)	(3,318)
Net cash provided by operating activities	30,774	30,247	169,303
Cash flows from investing activities			
Capital expenditures	(4,812)	(15,359)	(364,844)
Proceeds from sales of assets, net	—	224	85,189
Other, net	(104)	1,186	—
Net cash used in investing activities	(4,916)	(13,949)	(279,655)
Cash flows from financing activities			
(Repayments) proceeds from credit facility borrowings, net	(50,350)	(43,771)	135,000
Debt issuance costs paid	—	(3,011)	(744)
Proceeds from rights offering, net	—	49,943	—
Dividends paid on preferred stock	—	—	(18,201)
Other, net	(161)	—	—
Net cash (used in) provided by financing activities	(50,511)	3,161	116,055
Net (decrease) increase in cash and cash equivalents	$ (24,653)	$ 19,459	$ 5,703

Cash Flows From Operating Activities. The Successor period, which represents the period from September 13, 2016 through December 31, 2016, included ordinary course cash receipts and disbursements for product revenues and joint venture billing collections, net of payments for royalties, lease operating expenses, gathering, processing and transportation expenses, severance taxes and general and administrative expenses. We also received net derivative proceeds for three months, as well as the return of remaining funds, after allowed payments were disbursed to various professional firms, from the professional fee escrow that was established on the Effective Date. The Successor period includes interest payments, net of amounts capitalized, on the Credit Facility, payments for bankruptcy-related professional and advisory fees paid directly by us exclusive of the professional fee escrow and severance, termination and other retention bonuses paid to employees after the Effective Date.

The Predecessor period during 2016 represents January 1 through September 12, 2016 as compared to a full calendar year in 2015. Aggregate average commodity prices declined during the Predecessor period in 2016 compared to the Predecessor period in 2015. In addition, production declined due primarily to: (i) the shorter time period in the 2016 period, (ii) the suspension of our Eagle Ford drilling program in February 2016, (iii) natural production declines and (iv) the sale of our East Texas assets in August 2015 and certain other properties in the Eagle Ford and Mid-Continent regions in October 2015. The combined effect of these factors contributed to the substantial reduction in the realized cash receipts in the Predecessor period ended September 12, 2016 when compared to 2015. During the 2016 Predecessor period, we incurred and paid substantially higher professional fees and other costs associated with our consideration of strategic financing alternatives and our bankruptcy proceedings. In addition, we received lower settlements from derivatives during the 2016 period due primarily to: (i) lower spreads between hedged and realized prices on our post-petition derivatives through the Effective Date, (ii) lower overall crude oil volumes hedged, (iii) the early termination in 2016 of our entire pre-petition portfolio of derivative contracts, most of the proceeds from which were provided directly to the RBL lenders to pay down borrowings under the RBL, and (iv) the expiration of our natural gas hedges in 2015. This overall decline in operating cash flows was partially offset by: (i) the suspension of interest payments on the Senior Notes in connection with the bankruptcy proceedings, (ii) higher working capital utilization during 2015 as we paid down a substantial level of accounts payable and accrued expenses in 2015, (iii) higher payments in 2015 for the release of operated drilling rigs and (iv) required prepayments for certain oilfield services in 2015 due to the deterioration in our credit standing at that time.

Cash Flows From Investing Activities. As illustrated in the tables below, our cash payments for capital expenditures were substantially lower during the 2016 Successor and Predecessor periods compared to 2015 due primarily to the suspension of our capital program in February 2016. The drilling program was not resumed until November of 2016 in the Successor period. Furthermore, the 2016 Predecessor period includes substantially lower settlements of accrued capital charges from the prior year-end period.

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

	Successor	Predecessor	
	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Oil and gas:			
Drilling and completion	$ 4,839	$ 3,696	$ 284,225
Lease acquisitions and other land-related costs	93	58	16,052
Geological and geophysical (seismic) costs	567	(16)	828
Pipeline, gathering facilities and other equipment	(46)	375	3,884
	5,453	4,113	304,989
Other – Corporate	—	—	562
Total capital program costs	$ 5,453	$ 4,113	$ 305,551

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

	Successor	Predecessor	
	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Total capital program costs	$ 5,453	$ 4,113	$ 305,551
Decrease (increase) in accrued capitalized costs	(997)	11,301	55,660
Less:			
Exploration expenses charged to operations:			
Geological and geophysical (seismic) and delay rental costs	—	16	(939)
Transfers from tubular inventory and well materials	(272)	(465)	(4,570)
Add:			
Tubular inventory and well materials purchased in advance of drilling	61	211	2,854
Capitalized internal labor	542	—	—
Capitalized interest	25	183	6,288
Total cash paid for capital expenditures	$ 4,812	$ 15,359	$ 364,844

Our capital expenditures for the Predecessor period in 2016 and the year ended December 31, 2015 were partially offset by the receipt of net proceeds from the sale of assets. In the 2016 Predecessor period, we sold certain surplus tubular inventory and well equipment while 2015 includes the receipt of approximately $85 million of net proceeds from the sale of our East Texas assets and certain non-core Eagle Ford and Mid-Continent properties. The 2016 Successor period includes payments for certain items related to assets sold in prior periods in excess of proceeds received from the sale of surplus tubular inventory and well equipment. The 2016 Predecessor period also includes insurance recoveries from a casualty loss incurred in 2015.

The following table sets forth the net sales and other proceeds received for the periods presented:

	Successor	Predecessor	
	September 13 Through December 31, 2016	January 1 Through September 12, 2016	Year Ended December 31, 2015
Oil and gas properties, net	$ —	$ —	$ 84,967
Tubular inventory, well materials and other, net	—	224	222
	—	224	85,189
Insurance proceeds from casualty loss and other, net	(104)	1,186	—
	$ (104)	$ 1,410	$ 85,189

Cash Flows From Financing Activities. The 2016 Successor period includes the repayment of $50.4 million of the initial borrowing under the Credit Facility as well as the payment of $0.2 million of costs associated with the issuance and registration of New Common Stock. Cash flows from financing activities for the 2016 Predecessor period included repayments of $119.1 million under the RBL and initial borrowings of $75.4 million under the Credit Facility on the Effective Date, while the 2015 Predecessor period included net borrowings of $135 million under the RBL to fund our multi-rig capital program. We also realized net proceeds of $49.9 million from the Rights Offering that were used to pay down the RBL. We did not pay dividends on the Series A Preferred Stock and Series B Preferred Stock during the 2016 Predecessor period while the 2015 Predecessor period includes dividend payments of $18.2 million which were suspended on both preferred stock series in the third quarter of 2015. We paid issuance costs in the 2016 Predecessor period associated with the Credit Facility and in the 2015 Predecessor period associated with amendments to the RBL.

Capitalization

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

	Successor	Predecessor
	December 31, 2016	December 31, 2015
Revolving credit facility	$ 25,000	$ 170,000
Senior notes due 2019	—	300,000
Senior notes due 2020	—	775,000
Total debt	25,000	1,245,000
Shareholders’ equity [1]	185,548	(915,121)
	$ 210,548	$ 329,879
Debt as a % of total capitalization	12%	377%

[1] Includes 3,915 shares of the Series A Preferred Stock and 27,551 shares of the Series B Preferred Stock as of December 31, 2015. Both series of preferred stock, which were canceled on the Effective Date, had a liquidation preference of $10,000 per share representing a total of $314.7 million as of December 31, 2015.

Revolving Credit Facility. On the Effective Date, we entered into the Credit Facility. The Credit Facility provides for a $200 million revolving commitment and has an initial borrowing base of $128 million. The Credit Facility also includes a $5.0 million sublimit for the issuance of letters of credit, of which $0.8 million was outstanding as of December 31, 2016 . The Credit Facility is governed by a borrowing base calculation, which is redetermined semi-annually, and the availability under the Credit Facility may not exceed the lesser of the aggregate commitments and the borrowing base. The Credit Facility is scheduled for its initial redetermination in April 2017. After April 1, 2017, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) LIBOR plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on LIBOR borrowings is payable every one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days. As of December 31, 2016, the actual interest rate on the outstanding borrowings under the Credit Facility was 3.67%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by our parent company and all of our subsidiaries, or the Guarantor Subsidiaries. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company has no material independent assets or operations. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility, or adjusted EBITDAX, to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to adjusted EBITDAX), measured as of the last day of each fiscal quarter, initially of 4.00 to 1.00, decreasing on December 31, 2017 to 3.75 to 1.00 and on March 31, 2018 and thereafter to 3.50 to 1.00.

The Credit Facility also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

As of December 31, 2016, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of these covenants.

Senior Notes. The filing of the voluntary petitions seeking relief under Chapter 11 of the Bankruptcy Code constituted an event of default that accelerated our obligations under the indentures governing the Senior Notes. On September 12, 2016, the obligations of the Company and the Chapter 11 Subsidiaries with respect to these notes were canceled.

Results of Operations

The tabular presentations included below reflect the results of operations associated with the Successor period of 2016, which represents one full calendar quarter and 18 days, the Predecessor period of 2016, which represents eight months and 12 days, and the full calendar years of 2015 and 2014. As discussed previously in the *Overview and Executive Summary*, the adoption of Fresh Start Accounting and the full cost method of accounting for oil and gas properties on the Effective Date results in the Successor not being comparable to the Predecessor for purposes of financial reporting. While the Successor effectively represents a new reporting entity for financial reporting purposes, the impact is generally limited to those areas associated with the basis in and accounting for our oil and gas properties (specifically DD&A, impairments as well as exploration expenses), capital structure (specifically interest expense) and income taxes (due to the change in control). Accordingly, we believe that describing certain year-over-year variances and trends in our production, revenues and expenses for the calendar years 2016 and 2015 without regard to the concept of a Successor and Predecessor facilitates a meaningful analysis of our results of operations.

Substantial components of our year-over-year variances for 2015 to 2014 are due to the effects of property divestitures. In 2015, we sold all of our interests in the Haynesville Shale and Cotton Valley in East Texas as well as certain non-core properties in the Eagle Ford and Mid-Continent and in 2014 we sold all of our interests in the Selma Chalk in Mississippi. In the discussion and analysis that follows, the term “Divested properties” refers to the production, revenues and expenses associated with our former assets in those regions.

Production

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

	Total Production			
	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Crude oil (MBbl)	711	2,311	4,923	4,644
NGLs (MBbl)	164	533	1,381	1,110
Natural gas (MMcf)	994	3,013	9,713	13,085
Total (MBOE)	1,040	3,346	7,923	7,934
Combined 2016 vs. 2015 Variance (MBOE)			(3,537)	
% Change			(44.6)%	
2015 vs. 2014 Variance (MBOE)				(11)
% Change				(0.1)%

	Average Daily Production			
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Crude oil (Bbl per day)	6,463	9,028	13,523	12,723
NGLs (Bbl per day)	1,491	2,082	3,893	3,040
Natural gas (MMcf per day)	9	11	29	36
Total (BOEPD)	9,454	13,081	22,323	21,738
Combined 2016 vs. 2015 Variance (BOEPD)			(10,339)	
% Change			(46.3)%	
2015 vs. 2014 Variance (BOEPD)				585
% Change				2.7 %

	Total Production			
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
South Texas	937	3,071	6,903	5,817
Mid-Continent and other [1]	103	276	460	743
Divested properties [2]	—	—	560	1,374
Total (MBOE)	1,040	3,346	7,923	7,934
Combined 2016 vs. 2015 Variance (MBOE)			(3,537)	
% Change			(44.6)%	
2015 vs. 2014 Variance (MBOE)				(11)
% Change				(0.1)%

	Average Daily Production			
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
South Texas	8,518	11,996	18,913	15,937
Mid-Continent and other [1]	936	1,085	1,260	2,034
Divested properties [2]	—	—	2,150	3,765
Total (BOEPD)	9,454	13,081	22,323	21,738
Combined 2016 vs. 2015 Variance (BOEPD)			(10,339)	
% Change			(46.3)%	
2015 vs. 2014 Variance (BOEPD)				585
% Change				2.7 %

[1] Includes total production and average daily production of approximately 10 MBOE (48 BOEPD), 22 MBOE (60 BOEPD) and 24 MBOE (66 BOEPD) for 2016, 2015 and 2014, respectively, attributable to our three active Marcellus Shale wells.

[2] We sold all of our properties in the Haynesville Shale and Cotton Valley in East Texas in August 2015, which represented total production and average daily production of approximately 449 MBOE (1,847 BOEPD) and 844 MBOE (2,311 BOEPD) in 2015 and 2014, respectively. We sold all of our properties in the Selma Chalk in Mississippi in July 2014, which represented annual production and average daily production of approximately 412 MBOE (1,946 BOEPD) in 2014. We sold certain non-core properties in the Eagle Ford and Granite Wash in October 2015, which represented total production and average daily production of approximately 111 MBOE (364 BOEPD) and 118 MBOE (325 BOEPD) in 2015 and 2014, respectively.

2016 vs. 2015. Total production decreased during the combined Successor and Predecessor periods in 2016 when compared to 2015 due primarily to the suspension of our drilling program in February 2016, natural production declines in all of our operating regions and the sale of our East Texas assets in August 2015 and other non-core Eagle Ford and certain Mid-Continent properties in October 2015. Approximately 69 percent of total production during the combined Successor and Predecessor periods in 2016 was attributable to oil when compared to approximately 62 percent during 2015. Our Eagle Ford production represented over 91 percent of our total production during the combined Successor and Predecessor periods in 2016 when compared to approximately 87 percent from this region during 2015. During the Predecessor period in 2016, we turned in line five gross Eagle Ford wells compared to 61 gross wells that were brought on line during 2015.

2015 vs. 2014. Total production was essentially unchanged during 2015 compared to 2014. Production from the development of our Eagle Ford assets in South Texas offset natural production declines and the sale of our East Texas properties in August 2015. Approximately 62 percent of total production during 2015 was attributable to oil when compared to approximately 59 percent during 2014. During 2015, our Eagle Ford production represented approximately 87 percent of our total production compared to approximately 73 percent during 2014. During 2015, we turned in line 61 gross Eagle Ford wells compared to 93 gross wells that were brought on line during 2014. A substantial majority of these wells were brought on line during the first half of 2015 at a time when we were operating as many as eight drilling rigs.

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:

	Successor	Predecessor		
	Total Product Revenues			
	September 13 Through December 31, 2016	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Crude oil	$ 33,157	$ 81,377	$ 220,596	$ 420,286
NGLs	2,707	6,064	16,905	34,552
Natural gas	2,790	6,208	25,479	58,044
Total	$ 38,654	$ 93,649	$ 262,980	$ 512,882
Combined 2016 vs. 2015 Variance			$ (130,677)	
% Change			(49.7)%	
2015 vs. 2014 Variance				$ (249,902)
% Change				(48.7)%

	Product Revenues per Unit of Volume			
	September 13 Through December 31, 2016	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
Crude oil ($ per barrel)	$ 46.63	$ 35.21	$ 44.81	$ 90.50
NGLs ($ per barrel)	$ 16.51	$ 11.38	$ 12.24	$ 31.14
Natural gas ($ per Mcf)	$ 2.81	$ 2.06	$ 2.62	$ 4.44
Total ($ per BOE)	$ 37.17	$ 27.99	$ 33.19	$ 64.64
Combined 2016 vs. 2015 Variance ($ per BOE)			$ (3.02)	
% Change			(9.1)%	
2015 vs. 2014 Variance ($ per BOE)				$ (31.45)
% Change				(48.7)%

	Total Product Revenues			
	September 13 Through December 31, 2016	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
South Texas	$ 36,261	$ 88,849	$ 240,486	$ 432,792
Mid-Continent and other [1]	2,393	4,800	9,666	31,457
Divested properties [2]	—	—	12,828	48,633
Total	$ 38,654	$ 93,649	$ 262,980	$ 512,882
Combined 2016 vs. 2015 Variance			$ (130,677)	
% Change			(49.7)%	
2015 vs. 2014 Variance				$ (249,902)
% Change				(48.7)%

	Product Revenues per Unit of Volume			
	September 13 Through December 31, 2016	**January 1 Through September 12, 2016**	**Year Ended December 31, 2015**	**Year Ended December 31, 2014**
South Texas	$ 38.71	$ 28.94	$ 34.84	$ 74.40
Mid-Continent and other	$ 23.23	$ 17.41	$ 21.01	$ 42.37
Divested properties	$ —	$ —	$ 22.91	$ 35.40
Total ($ per BOE)	$ 37.17	$ 27.99	$ 33.19	$ 64.64
Combined 2016 vs. 2015 Variance ($ per BOE)			$ (3.02)	
% Change			(9.1)%	
2015 vs. 2014 Variance ($ per BOE)				$ (31.45)
% Change				(48.7)%

[1] Includes revenues of $0.1 million, $0.2 million and $0.5 million attributable to the Marcellus Shale for the Successor period in 2016 and the years ended December 31,2015 and 2014, respectively.

[2] Includes revenues of $8.2 million and $28.2 million attributable to East Texas for 2015 and 2014, respectively, that we sold in August 2015 and $12.0 million attributable to Mississippi for 2014 that we sold in July 2014. Includes revenues of $4.3 million and $7.8 million for 2015 and 2014, respectively, attributable to non-core Eagle Ford properties that we sold in October 2015. Includes revenues of $0.4 million and $0.7 million attributable to certain Mid-Continent properties that we sold in October 2015.

The following table provides an analysis of the changes in our revenues for the periods presented:

	Combined 2016 Successor and Predecessor vs. 2015 Revenue Variance Due to			2015 vs. 2014 Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ (85,180)	$ (20,882)	$ (106,062)	$ 25,263	$ (224,953)	$ (199,690)
NGLs	(8,371)	237	(8,134)	8,454	(26,101)	(17,647)
Natural gas	(14,998)	(1,483)	(16,481)	(14,957)	(17,608)	(32,565)
	$ (108,549)	$ (22,128)	$ (130,677)	$ 18,760	$ (268,662)	$ (249,902)

Effects of Derivatives

The following table reconciles crude oil and natural gas revenues to realized prices, as adjusted for derivative activities, for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Crude oil revenues as reported	$ 33,157	$ 81,377	$ 220,596	$ 420,286
Derivative settlements, net	384	48,008	137,488	(6,170)
	$ 33,541	$ 129,385	$ 358,084	$ 414,116
Crude oil prices per Bbl, as reported	$ 46.63	$ 35.21	$ 44.81	$ 90.50
Derivative settlements per Bbl	0.54	20.77	27.93	(1.33)
	$ 47.17	$ 55.98	$ 72.74	$ 89.17
Natural gas revenues as reported	$ 2,790	$ 6,208	$ 25,479	$ 58,044
Derivative settlements, net	—	—	681	(1,254)
	$ 2,790	$ 6,208	$ 26,160	$ 56,790
Natural gas prices per Mcf, as reported	$ 2.81	$ 2.06	$ 2.62	$ 4.44
Derivative settlements per Mcf	—	—	0.07	(0.10)
	$ 2.81	$ 2.06	$ 2.69	$ 4.34

Gain (Loss) on Sales of Assets

2016. The Predecessor period in 2016 includes $1.7 million from the amortization of deferred gains attributable to our 2014 sale of rights to construct a crude oil gathering and intermediate transportation system. The amortization of $0.3 million of deferred gains from the 2014 sale of our South Texas natural gas gathering and gas lift assets is also included for the Predecessor period. As of the Effective Date, the unamortized portions of those deferred gains were reversed from our Consolidated Balance Sheet in connection with our application of Fresh Start Accounting and included as a component of Reorganization items, net.

2015. In 2015, we recognized a gain of approximately $43 million on the sale of our East Texas assets. Additionally, in connection with an amendment to our crude oil gathering agreement with Republic which included a pricing concession, we recognized $8.4 million of the gain that was previously deferred and being recognized over the term of the underlying agreement. In 2015, we also recognized $0.4 million of deferred gain from the 2014 sale of our natural gas gathering and gas lift assets in South Texas. These gains were partially offset by a loss of $9.5 million from the sale of certain non-core Eagle Ford properties and a combined loss of $1.2 million from other sale transactions and post-closing adjustments attributable to prior year asset sales.

2014. In 2014, we recognized a gain of $63.0 million in connection with the sale to Republic of rights to construct a crude oil gathering and intermediate transportation system and a gain of $57.1 million on the sale of our natural gas gathering and gas lift assets in South Texas, including $56.7 million recognized upon the closing of the sale and $0.4 million attributable to the deferred portion of the gain.

Other Revenues

2016 vs. 2015. Other revenues, which include gathering, transportation, marketing, compression, water supply and disposal fees that we charge to third parties, net of marketing and related expenses as well as accretion, through the Predecessor period, of our unused firm transportation obligation, decreased during the Successor and Predecessor periods in 2016 from 2015 due primarily to substantially lower drilling activity in our operating areas. Certain of these revenue sources also declined due to the sale of our East Texas assets in August 2015. In addition, we realized lower water supply and disposal fees in the South Texas region during the Successor and Predecessor periods in 2016 due to decreased demand in the region. We also reserved certain of our receivables from joint venture partners in the Predecessor period in 2016 which are presented as contra-revenue items in this caption.

2015 vs. 2014. Other revenues decreased during 2015 from 2014. Certain of these revenue sources declined following the sale of our assets in East Texas where we provided services to other producers. The declines were partially offset by revenue from water disposal facilities that were brought on-line in 2015.

Lease Operating Expenses

Lease operating expenses, or LOE, includes costs that we incur to operate our producing wells and field operations. The most significant costs include compression and gas-lift, chemicals, water disposal, repairs and maintenance, including down-hole repairs, field labor, pumping and well-tending, equipment rentals, utilities and supplies among others.

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Lease operating	$ 5,331	$ 15,626	$ 42,428	$ 48,298
Per unit of production ($/BOE)	$ 5.13	$ 4.67	$ 5.36	$ 6.09

2016 vs. 2015. LOE decreased during the combined Successor and Predecessor periods in 2016 on an absolute and per unit basis when compared to 2015 due primarily to lower overall production, cost containment efforts that we implemented throughout 2016 and lower industry-wide pricing for certain oilfield products and services. The Predecessor period in 2015 included $4.2 million of LOE attributable to our East Texas assets that were sold in August 2015.

2015 vs. 2014. LOE in our South Texas region increased $6.2 million in 2015 on an absolute basis commensurate with higher production. This regional increase was also due to higher gas lift and compression costs as well as down-hole repairs, particularly in the first half of 2015. The increase in South Texas LOE for 2015 was partially offset by a $1.7 million decline in other areas due primarily to lower production volumes. The sale of our East Texas assets in 2015 and Mississippi assets in 2014 resulted in a total decrease of $10.4 million in LOE costs for 2015 compared to 2014.

Gathering Processing and Transportation

Gathering, processing and transportation, or GPT, includes costs that we incur to gather and aggregate our oil, NGL and natural gas production from our wells and deliver them to a central delivery point, downstream pipelines or processing plants, depending upon the type of production and the specific arrangements that we have with midstream operators.

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Gathering, processing and transportation	$ 3,043	$ 13,235	$ 23,815	$ 18,294
Per unit of production ($/BOE)	$ 2.93	$ 3.96	$ 3.01	$ 2.31

2016 vs. 2015. Gathering, processing and transportation, or GPT, charges decreased on an absolute basis during the combined Successor and Predecessor periods in 2016 when compared to 2015 due primarily to substantially lower production volumes in the South Texas region as discussed above. We also experienced a decline in the Successor and Predecessor periods in 2016 resulting from the sale of our East Texas assets in August 2015 as well as lower natural gas and NGL production in the Mid-Continent during the 2016 Successor and Predecessor periods when compared to 2015. The decrease in 2016 was partially offset by charges associated with volume deficiencies in 2016 attributable to our throughput commitments to Republic as well as higher costs for unused firm transportation services in the Marcellus in the 2016 period prior to our termination of operations in that region. Per unit rates increased during the 2016 Successor and Predecessor periods primarily due to higher rates under the oil gathering services commenced by Republic in April 2016.

2015 vs. 2014. GPT charges increased $6.4 million during 2015 compared to 2014 due primarily to higher South Texas production volumes including an increase in NGL and natural gas production from our Eagle Ford wells. NGL and natural gas production increased to 17 percent and 14 percent of total South Texas production in 2015 compared to 13 percent and 12 percent in 2014. This increase was partially offset by $0.5 million of lower GPT charges for our Mid-Continent region commensurate with a decline in production volume from that region. We also experienced further decreases of $0.4 million resulting from the sale of our East Texas assets in 2015 and our Mississippi assets in 2014.

Production and Ad Valorem Taxes

Production or severance taxes represent taxes imposed by the states in which we operate for the removal of resources including crude oil, NGLs and natural gas. Ad valorem taxes represent taxes imposed by certain jurisdictions, primarily counties, in which we operate, based on the value of our operating properties. The assessments for ad valorem taxes are generally based on contemporary commodity prices.

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Production and ad valorem taxes				
Production/severance taxes	$ 1,801	$ 2,695	$ 11,796	$ 22,567
Ad valorem taxes	697	795	4,486	5,423
	$ 2,498	$ 3,490	$ 16,282	$ 27,990
Per unit of production ($/BOE)	$ 2.40	$ 1.04	$ 2.06	$ 3.53
Production/severance tax rate as a percent of product revenues	4.7 %	2.9 %	4.5%	4.4%

2016 vs. 2015. Production taxes in the South Texas region declined substantially during the combined Successor and Predecessor periods in 2016 when compared to 2015 due primarily to the overall decline in production volume and commodity prices. In the 2016 Predecessor period, we adjusted our accruals for ad valorem taxes downward, primarily in South Texas, reflecting lower oil and gas property valuations attributable to the significant decline in commodity prices. These adjustments resulted in a significant downward impact on the per unit cost for the Predecessor period in 2016. We also recognized certain severance tax refunds attributable to prior periods in the Mid-Continent and other region during the Predecessor period in 2016.

2015 vs. 2014. Production taxes in the South Texas region declined substantially during 2015 compared to 2014 due primarily to significantly lower prices for commodity products despite increased production volumes. Production declines in our other operating regions as well as the sale of our East Texas assets in 2015 and our Mississippi assets in 2014 also contributed to the decline. Ad valorem taxes declined during 2015 compared to 2014 due to lower assessment values impacted by lower overall commodity prices.

General and Administrative

The following table sets forth the components of general and administrative expenses for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Primary general and administrative expenses	$ 5,087	$ 15,596	$ 32,353	$ 39,105
Shares-based compensation (liability-classified)	—	(19)	(711)	4,520
Shares-based compensation (equity-classified)	81	1,511	4,540	3,627
Significant special charges:				
Strategic and financial advisory costs	—	18,036	6,189	—
ERP system development costs	—	—	—	1,154
Acquisition-related costs	—	—	—	589
Restructuring expenses	(80)	3,821	957	10
Total general and administrative expenses	$ 5,088	$ 38,945	$ 43,328	$ 49,005
Per unit of production ($/BOE)	$ 4.89	$ 11.64	$ 5.47	$ 6.18
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 4.89	$ 4.66	$ 4.08	$ 4.93

2016 vs. 2015. Our primary G&A expenses during the combined Successor and Predecessor periods in 2016 decreased on an absolute basis and increased on a per unit basis. The Successor period includes $1.7 million of cash-based incentive compensation charges to certain of our employees for the post-emergence period. This charge would have normally been accrued throughout the calendar year, but was charged exclusively to the Successor period as the accrual became effective after the emergence from bankruptcy. Our primary G&A expenses during both the Successor and Predecessor periods in 2016 reflect the effects of: (i) lower payroll and benefits attributable to lower employee headcount, (ii) the relocation of our headquarters from Radnor, Pennsylvania to Houston, Texas and related move to a smaller office location, (iii) reduced travel and entertainment and (iv) lower corporate support costs consistent with our efforts throughout the 2016 periods to reduce our support cost base.

Liability-classified share-based compensation in the Predecessor periods was attributable to our performance-based restricted stock units, or PBRSUs, and represents mark-to-market charges associated with the change in fair value of the then outstanding PBRSU grants. Our Predecessor common stock performance relative to a defined peer group was less favorable during the 2016 Predecessor period resulting in a mark-to-market reversal. All of the unvested PBRSUs were canceled on the Effective Date.

Equity-classified share-based compensation charges during the Successor period of 2016 were attributable to restricted stock unit grants to one executive and the board of directors in 2016, while the Predecessor periods in 2016 and 2015 were attributable to the Predecessor's stock options and restricted stock units, all of which represented non-cash expenses.

During the 2016 Predecessor period, we incurred substantial professional fees and other consulting costs associated with our consideration of strategic financing alternatives and related activities in advance of our bankruptcy filing. In 2015, we incurred $6.2 million in professional fees and consulting costs associated with certain strategic initiatives, including our refinancing efforts and our search for a new chief executive officer.

In connection with our ongoing efforts to simplify and reduce our administrative cost structure, we terminated a total of 53 employees and incurred termination and severance benefits during the Predecessor period in 2016 as compared to a total of 26 employee terminations in 2015 for which we also incurred severance and termination benefits.

2015 vs. 2014. Our primary G&A expenses decreased on both an absolute and per unit basis during 2015 compared to 2014. Decreases in primary G&A expenses were due primarily to lower payroll and benefits attributable to lower employee headcount, substantially lower cash-based incentive compensation, reduced travel and entertainment and lower corporate support costs.

Our Predecessor common stock performance relative to a defined peer group was less favorable during 2015 compared to 2014 resulting in a reduction in liability-classified share-based compensation.

Equity-classified share-based compensation charges attributable to stock options and restricted stock units increased during 2015 compared to 2014 due primarily to a higher weighting of share-based awards over cash-based awards with respect to the compensation program for our senior management.

In 2015, we incurred professional fees and other consulting costs associated with certain strategic initiatives, as discussed above. In 2014, we incurred certain costs not eligible for capitalization, including post-implementation support and training with respect to our ERP system replacement. In 2014, we also incurred costs including legal and litigation support fees attributable to an acquisition-related arbitration matter.

Exploration

While applying the successful efforts method of accounting to our oil and gas properties during the Predecessor period in 2016 and the years ended December 31, 2015 and 2014, we incurred costs which were charged to operations in accordance with the successful efforts method. The following table sets forth the components of exploration expenses for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Unproved leasehold amortization	$ —	$ 1,940	$ 5,759	$ 10,346
Drilling rig termination charges	—	1,705	5,885	751
Drilling carry commitment	—	1,964	—	—
Geological and geophysical costs (seismic)	—	33	828	5,106
Other, primarily write-off of uncompleted wells	—	4,646	111	860
	$ —	$ 10,288	$ 12,583	$ 17,063

2016 vs. 2015. On the Effective Date we adopted the full cost method of accounting for our oil and gas properties. Accordingly, there are no exploration expenses recorded for the Successor period. With respect to the Predecessor period in 2016, we experienced lower unproved leasehold amortization attributable to a declining leasehold asset base subject to amortization. We also incurred early termination charges in connection with the release of drilling rigs in the Eagle Ford in each of the 2016 and 2015 Predecessor periods; however, the 2015 periods include the release of multiple rigs while the 2016 periods reflect the release of only one rig. Seismic and delay rental costs declined in the Predecessor period in 2016 compared to 2015 due to the suspension of our drilling program. These reductions were partially offset by a charge of $4.0 million for the write-off of certain uncompleted well costs prior to the aforementioned change in accounting method, a $2.0 million charge attributable to our failure to complete a drilling carry requirement attributable to certain acreage acquired in the Eagle Ford in 2014, and a charge of $0.6 million for coiled tubing services that were not utilized by the contract expiration date.

2015 vs. 2014. The sale of our East Texas assets in 2015 and Mississippi assets in 2014 resulted in a $3.0 million reduction in unproved leasehold amortization in 2015 compared to 2014. The declining leasehold asset base subject to amortization, primarily in the Mid-Continent and other region, accounted for the remainder of the decrease in amortization. We incurred early termination charges in connection with the release of three drilling rigs in Eagle Ford during 2015 compared to one early release in 2014. Seismic and delay rental costs declined in 2015 compared to 2014 due to a significant decrease in our capital program and limited exploration activity.

Depreciation, Depletion and Amortization (DD&A)

As discussed with respect to exploration expenses above, our adoption of the full cost method in place of the successful efforts method of accounting for oil and gas properties also impacted the determination of our DD&A during the Successor period in 2016 as compared to the Predecessor period in 2016 and the years ended December 31, 2015 and 2014. For a more detailed discussion of the determination of our DD&A, see the discussion of "*Critical Accounting Estimates*" that follows as well as Note 3 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." The following table sets forth the nature of the DD&A variances for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
DD&A expense	$ 11,652	$ 33,582	$ 334,479	$ 300,299
DD&A rate ($/BOE)	$ 11.20	$ 10.04	$ 42.22	$ 37.85

2016 vs. 2015. The effects of lower production volumes and the effects of lower depletion rates resulting from Fresh Start Accounting, impairments recorded in the fourth quarter of 2015 and an overall reduction in reserves in 2015 were the primary factors attributable to the decline in DD&A during the Successor and Predecessor periods in 2016 when compared to 2015.

2015 vs. 2014. Higher depletion rates attributable to the higher-cost drilling program in the Eagle Ford, followed by a downward revision of reserves in that region, were the primary factor leading to the increase in DD&A expense recognized in 2015 compared to 2014.

Impairments

2016 vs. 2015. We had no impairments during the 2016 Successor period while we applied the full cost method of accounting for our oil and gas properties and no impairments during the 2016 Predecessor period while we applied the successful efforts method for our oil and gas properties. The significant deterioration of commodity prices throughout 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties and required us to reduce their carrying value to a fair value of approximately $312 million. In 2015, we also recorded an impairment charge of $1.1 million attributable to surplus tubular inventory and well materials.

2015 vs. 2014. In 2015, we recorded the aforementioned $1.4 billion impairment and in 2014, we recognized oil and gas asset impairments of: (i) $667.8 million in the East Texas, Granite Wash and Marcellus regions due to the decline in commodity prices in the fourth quarter of 2014, (ii) $6.1 million in connection with an uneconomic field drilled in the Mid-Continent region and (iii) $117.9 million to write-down our Selma Chalk assets in Mississippi triggered by the disposition of those properties.

Interest Expense

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

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Interest on borrowings and related fees	$ 678	$ 36,012	$ 92,490	$ 91,866
Amortization of debt issuance costs	226	22,189	4,749	4,197
Capitalized interest	(25)	(183)	(6,288)	(7,232)
	$ 879	$ 58,018	$ 90,951	$ 88,831

2016 vs. 2015. Interest expense during the Successor period is exclusively attributable to the Credit Facility. Interest expense during the Predecessor periods of 2016 and 2015 is attributable to the RBL and the Senior Notes except for the period from the Petition Date through the Effective Date, which excludes interest on the Senior Notes due primarily to the suspension of interest accruals thereon in connection with the bankruptcy filing. The 2016 Predecessor period also includes a $20.5 million accelerated write-off of our issuance costs associated with the RBL and Senior Notes in advance of our bankruptcy filings.

2015 vs. 2014. Interest expense increased during 2015 compared to 2014 due primarily to (i) higher weighted-average debt outstanding under the RBL, (ii) higher amortization of debt issuance costs for the 2019 Senior Notes and the 2020 Senior Notes, based on the effective interest method of amortization, (iii) higher amortization of RBL issuance costs due to costs incurred to amend the RBL in the fourth quarter of 2014 and second quarter of 2015 and (iv) lower capitalized interest as the balance of capital projects subject to capitalization declined commensurate with the overall reduction in our 2015 capital program.

Derivatives

The following table summarizes the gains and (losses) attributable to our commodity derivatives portfolio, by commodity type, for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Crude oil derivative gains (losses)	$ (16,622)	$ (8,333)	$ 71,244	$ 162,916
Natural gas derivative gains (losses)	—	—	3	(704)
	$ (16,622)	$ (8,333)	$ 71,247	$ 162,212

2016 vs. 2015. The gains and losses for our derivatives portfolio reflect changes in the fair value attributable to changes in market values relative to our hedged commodity prices. We received net cash settlements for crude oil derivatives during each of the Successor and Predecessor periods in 2016 and 2015 of $0.4 million, $48.0 million and $137.5 million, respectively, and received cash settlements of $0.7 million for natural gas derivatives during 2015. The decline in total cash settlements is attributable to: (i) lower spreads between hedged and realized prices on our post-petition derivatives, (ii) lower overall crude oil volumes hedged, (iii) the early termination of our entire pre-petition portfolio of 2016 derivative contracts, most of the proceeds from which were provided directly to the RBL lenders to pay down borrowings under the RBL prior to the Petition Date and (iv) the expiration of our natural gas hedges in the 2015 period.

2015 vs. 2014. During 2015, we received cash settlements of $137.5 million from crude oil derivatives as compared to the payment of cash settlements of $6.2 million during 2014. The crude oil derivative portfolio was “in-the-money,” throughout all of 2015 as a result of declining prices compared to the hedge contract prices. Our natural gas hedges expired in 2015 and provided $0.7 million of cash receipts from settlements in 2015 while requiring the payment of cash settlements of $1.2 million during 2014.

Other, net

2016. In the Successor period of 2016, we reversed $0.9 million representing a portion of a reserve recognized in the Predecessor period of 2016 attributable to a prior-year acquisition-related receivable. This item was partially offset by the write-off of certain acquisition-related joint interest billing receivables and a decline in the market value of the SERP assets prior to their reversion to us. In the Predecessor period of 2016, we initially reserved the aforementioned acquisition-related receivable for $2.9 million and wrote-off unrecoverable amounts from prior years, including severance tax receivables, certain joint interest billing receivables, GPT and other revenue deductions due from other parties of $0.6 million, all of which were attributable primarily to properties that were sold in prior years. These items were partially offset by a vendor settlement of $0.3 million also attributable to prior periods.

2015. In 2015, we wrote-off a combined $1.6 million of receivables from various joint interest partners and other parties that we determined were not collectible as well as approximately $2.0 million of unrecoverable amounts from prior years, including GPT and other revenue deductions, attributable primarily to properties that have been sold.

2014. In 2014, we recognized $1.3 million of interest received in connection with an acquisition-related arbitration matter.

Reorganization Items, net

The following table summarizes the components included in "Reorganization items, net" for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Gains on the settlement of liabilities subject to compromise	$ —	$ 1,150,248	$ —	$ —
Fresh Start Accounting adjustments	—	28,319	—	—
Legal and professional fees and expenses	—	(29,976)	—	—
Settlements attributable to contract amendments	—	(2,550)	—	—
DIP Facility costs and commitment fees	—	(170)	—	—
Write-off of prepaid directors and officers insurance	—	(832)	—	—
Other reorganization items	—	(46)	—	—
	$ —	$ 1,144,993	$ —	$ —

The gains on the settlement of liabilities subject to compromise are primarily attributable to the Senior Notes and interest thereon. The Fresh Start Accounting adjustments include those fair value adjustments attributable to our property and equipment, AROs, retiree benefit obligations and the accelerated recognition of previously deferred gains of the Predecessor. The legal and professional fees that we incurred were attributable to our advisers as well as those of the Ad Hoc Committee, the UCC, the RBL lenders and the indenture trustee under the Senior Notes. We paid settlements in cash with respect to certain critical contract amendments. While we did not borrow any amounts under the DIP facility from the Petition Date through the Effective Date, we paid certain costs and fees to arrange and maintain the DIP facility during this term. Upon emergence from bankruptcy, we wrote off certain prepaid directors and officers insurance attributable to the Predecessor. The items described herein are also described in further detail in Note 5 to the Consolidated Financial Statements.

Income Taxes

The following table summarizes our income tax benefits for the periods presented:

	Successor	Predecessor		
	September 13 Through December 31,	January 1 Through September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Income tax benefit	$ —	$ —	$ 5,371	$ 131,678
Effective tax rate	—%	—%	0.3%	24.3%

2016. We recognized a federal income tax benefit for each of the periods Successor and Predecessor periods in 2016 at the statutory rate of 35%; however, the federal tax benefit was fully offset by a valuation allowance against our net deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of our cumulative losses.

We have evaluated the impact of the reorganization, including the change in control, resulting from our emergence from bankruptcy. From an income tax perspective, the most significant impact is attributable to our carryover tax attributes associated with our net operating losses, or NOLs. We believe that the Successor will be able to fully absorb the cancellation of debt income realized by the Predecessor in connection with the reorganization with its adjusted NOL carryovers. The amount of the remaining NOL carryovers and the tax basis of our properties will be limited under Section 382 of the Internal Revenue Code due to the change in control as referenced in the summary of *Key Developments*. As the tax basis of our assets, primarily our oil and gas properties, is in excess of the carrying value, as adjusted in the Fresh Start Accounting process, the Successor is in a net deferred tax asset position. We have determined that it is more likely than not that we will not realize future income tax benefits from the additional tax basis and our remaining NOL carryovers. Accordingly, we have provided for a full valuation allowance of the underlying deferred tax assets.

2015. We recognized a federal income tax benefit for 2015 at the statutory rate of 35%; however, the federal tax benefit was fully offset by a valuation allowance against our net deferred tax assets. We also provided for a full valuation allowance against our state deferred tax assets. We considered both the positive and negative evidence in determining that it was more likely than not that some portion or all of our deferred tax assets will not be realized, primarily as a result of recent cumulative losses. We also recognized a benefit of $0.7 million attributable to a federal return to provision adjustment and a minimal deferred state income tax expense resulting in a combined effective tax rate of 0.3% for 2015. The significant difference between our combined federal and state statutory rate of 35.7% and our effective tax of 0.3% is due almost entirely to the incremental valuation allowance placed against our deferred tax assets.

2014. Due to the pre-tax operating loss incurred in 2014, we recognized an income tax benefit. Our income tax benefit was reduced by a combined federal and state $62.8 million valuation allowance against our net deferred tax assets. The federal portion of the valuation allowance was $61.1 million which reduced the carrying value of our federal net deferred tax assets to zero. The significant difference between our blended federal and state statutory income tax rate of 35.7% and our effective income tax rate of 24.3% in 2014 was almost entirely attributable to the incremental valuation allowance placed against our deferred tax assets. Absent this valuation allowance, our effective income tax rate would have been 35.6%.

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, 2016, the material off-balance sheet arrangements and transactions that we have entered into included operating lease arrangements, information technology licensing, service agreements, employment agreements and letters of credit, all of which are customary in our business. See “Contractual Obligations” summarized below and Note 16 to the Consolidated Financial Statements 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 had we engaged in such relationships.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2016:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit Facility [1]	$ 25,000	$ —	$ —	$ 25,000	$ —
Interest payments on long-term debt [2]	3,402	917	1,835	650	—
Operating leases [3]	565	264	260	41	—
Crude oil gathering and transportation commitments [4]	134,322	9,646	22,078	25,924	76,674
Asset retirement obligations [5]	68,309	—	—	—	68,309
Derivatives	27,369	12,932	14,437	—	—
Other commitments [6]	667	596	71	—	—
Total contractual obligations	$ 259,634	$ 24,355	$ 38,681	$ 51,615	$ 144,983

[1] Assumes that the amount outstanding of $25 million as of December 31, 2016 will remain outstanding until its maturity in 2020. The Credit Facility has been classified as a long term liability on our Consolidated Balance Sheet as described in “Financial Condition – Liquidity” and in Note 11 to the Consolidated Financial Statements.

[2] Represents estimated interest payments that will be due under the Credit Facility, assuming the amount outstanding of $25 million as of December 31, 2016 will remain outstanding until its maturity in 2020.

[3] Relates primarily to office and equipment leases.

[4] Represents minimum payments for gathering and intermediate pipeline transportation services for our crude oil and condensate production in South Texas. The gathering portion of these commitments is recognized as GPT while the intermediate transportation and pipeline support components are recognized as a reduction to the index-based price that we receive from crude oil sold to Republic.

[5] Represents the undiscounted balance payable in periods more than five years in the future for which $2.5 million has been recognized on our Consolidated Balance Sheet as of December 31, 2016. While we could make 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.

[6] Represents all other significant obligations, including 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.

Fresh Start Accounting

Upon the Effective Date, we adopted Fresh Start Accounting. Fresh Start Accounting involved a comprehensive valuation process in which we determined the fair value of all of our assets and liabilities on the Effective Date. This process, which is more fully described in Note 5 to our Consolidated Financial Statements included in Item II, Part 8, "Financial Statements and Supplementary Data," utilized several critical estimates associated with, among other items, our development plans, financial projections, regional and broader market conditions as well as an estimated discount rate.

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 and the recoverability of historical cost investments. 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 as well as changes in our drilling plans 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

Beginning on the Effective Date, we have applied the full cost method to account for our oil and gas properties. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of DD&A.

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case, the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes, or a Ceiling Test. The estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development.

Depreciation, Depletion and Amortization

DD&A of our oil and gas properties is computed using the units-of-production method. We apply this method by multiplying the unamortized cost of our proved oil and gas properties, net of estimated salvage plus future development costs, by a rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period.

Derivative Activities

From time to time, we enter into derivative instruments to mitigate our exposure to commodity 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 Predecessor 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 at the federal level as well as certain states in which we operate. Estimates of future taxable income inherently reflect a significant degree of uncertainty. As of December 31, 2016, we had a full valuation allowance for our deferred tax assets due primarily to our inability to project sufficient future taxable income in both the federal and various state jurisdictions.

Disclosure of the Impact of Recently Issued Accounting Standards to be Adopted in the Future

In June 2016, the Financial Accounting Standards Board, or the FASB, issued Accounting Standards Update, or ASU, 2016–13, *Measurement of Credit Losses on Financial Instruments*, or ASU 2016–13, which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an “incurred loss” model), ASU 2016–13 mandates an “expected loss” model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are currently in the early stages of evaluating the requirements and the period for which we will adopt the standard.

In February 2016, the FASB issued ASU 2016–02, *Leases*, or ASU 2016–02, which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 16, our existing leases for office facilities and certain office equipment and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent that we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard, however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers*, or ASU 2014–09, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, natural gas imbalances and other non-product revenues, including our ancillary marketing, gathering and transportation and water service revenues could be affected. Accordingly, we are continuing to evaluate the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures, with a more focused analysis on these other revenue sources, which we do not believe are significant. We are also continuing to monitor developments regarding ASU 2014–09 that are unique to our industry. We fully expect to adopt ASU 2014–09 in 2018.

Item 8 Financial Statements and Supplementary Data

PENN VIRGINIA CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Penn Virginia Corporation

We have audited the accompanying consolidated balance sheet of Penn Virginia Corporation (a Virginia corporation) and subsidiaries (the "Company") as of December 31, 2016 (Successor), and the related consolidated statements of operations, comprehensive income (loss), cash flows, and shareholders' equity for the period from September 13, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through September 12, 2016 (Predecessor). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

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, 2016 (Successor), and the results of their operations and their cash flows for the period from September 13, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through September 12, 2016 (Predecessor) in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4 to the consolidated financial statements, on August 11, 2016, the United States Bankruptcy Court for the Eastern District of Virginia entered an order confirming the plan for reorganization, which became effective on September 12, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852, *Reorganizations*, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 2.

/s/ GRANT THORNTON LLP

Houston, Texas
March 16, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Penn Virginia Corporation:

We have audited the accompanying consolidated balance sheet of Penn Virginia Corporation and subsidiaries as of December 31, 2015, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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, 2015, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements in the 2015 Form 10-K, the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in note 2 to the consolidated financial statements in the 2015 Form 10-K. The consolidated financial statements as of December 31, 2015 do not include any adjustments that might result from the outcome of this uncertainty.

/s/ KPMG LLP

Houston, Texas
March 15, 2016

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

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues				
Crude oil	$ 33,157	$ 81,377	$ 220,596	$ 420,286
Natural gas liquids	2,707	6,064	16,905	34,552
Natural gas	2,790	6,208	25,479	58,044
Gain (loss) on sales of assets, net	(49)	1,261	41,335	120,769
Other, net	398	(600)	983	3,122
Total revenues	39,003	94,310	305,298	636,773
Operating expenses				
Lease operating	5,331	15,626	42,428	48,298
Gathering, processing and transportation	3,043	13,235	23,815	18,294
Production and ad valorem taxes	2,498	3,490	16,282	27,990
General and administrative	5,088	38,945	43,328	49,005
Exploration	—	10,288	12,583	17,063
Depreciation, depletion and amortization	11,652	33,582	334,479	300,299
Impairments	—	—	1,397,424	791,809
Total operating expenses	27,612	115,166	1,870,339	1,252,758
Operating income (loss)	11,391	(20,856)	(1,565,041)	(615,985)
Other income (expense)				
Interest expense	(879)	(58,018)	(90,951)	(88,831)
Derivatives	(16,622)	(8,333)	71,247	162,212
Other, net	814	(3,184)	(3,587)	1,334
Reorganization items, net	—	1,144,993	—	—
Income (loss) before income taxes	(5,296)	1,054,602	(1,588,332)	(541,270)
Income tax benefit	—	—	5,371	131,678
Net income (loss)	(5,296)	1,054,602	(1,582,961)	(409,592)
Preferred stock dividends	—	(5,972)	(22,789)	(17,148)
Induced conversion of preferred stock	—	—	—	(4,256)
Net income (loss) attributable to common shareholders	$ (5,296)	$ 1,048,630	$ (1,605,750)	$ (430,996)
Net income (loss) per share:				
Basic	$ (0.35)	$ 11.91	$ (21.81)	$ (6.26)
Diluted	$ (0.35)	$ 8.50	$ (21.81)	$ (6.26)
Weighted average shares outstanding – basic	14,992	88,013	73,639	68,887
Weighted average shares outstanding – diluted	14,992	124,087	73,639	68,887

See accompanying notes to consolidated financial statements.

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

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net income (loss)	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)
Other comprehensive income (loss):				
Change in pension and postretirement obligations, net of tax of $39 for the Successor period from September 13, 2016 through December 31, 2016, $(226) for the Predecessor period from January 1, 2016 through September 12, 2016, and $93 and $(10), for 2015 and 2014, respectively	73	(421)	173	(18)
	73	(421)	173	(18)
Comprehensive income (loss)	$ (5,223)	$ 1,054,181	$ (1,582,788)	$ (409,610)

See accompanying notes to consolidated financial statements.

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

	Successor		Predecessor	
	December 31,			
	2016		2015	
Assets				
Current assets				
Cash and cash equivalents	$	6,761	$	11,955
Accounts receivable, net of allowance for doubtful accounts		29,095		47,965
Derivative assets		—		97,956
Other current assets		3,028		7,104
Total current assets		38,884		164,980
Property and equipment, net		247,473		344,395
Other assets		5,329		8,350
Total assets	$	291,686	$	517,725
Liabilities and Shareholders' Equity (Deficit)				
Current liabilities				
Accounts payable and accrued liabilities	$	49,697	$	103,525
Derivative liabilities		12,932		—
Current portion of long-term debt, net of unamortized issuance costs		—		1,224,383
Total current liabilities		62,629		1,327,908
Other liabilities		4,072		104,938
Derivative liabilities		14,437		—
Deferred income taxes		—		—
Long-term debt		25,000		—
Commitments and contingencies (Note 16)				
Shareholders' equity (deficit):				
Predecessor preferred stock of $100 par value – 100,000 shares authorized; Series A – 3,915 shares issued as of December 31, 2015 and Series B – 27,551 shares issued as of December 31, 2015, each with a redemption value of $10,000 per share		—		3,146
Predecessor common stock of $0.01 par value – 228,000,000 shares authorized; 81,252,676 shares issued as of December 31, 2015		—		628
Predecessor paid-in capital		—		1,211,088
Predecessor deferred compensation obligation		—		3,440
Predecessor accumulated other comprehensive income		—		422
Predecessor treasury stock – 455,689 shares of common stock, at cost, as of December 31, 2015		—		(3,574)
Successor preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued		—		—
Successor common stock of $0.01 par value – 45,000,000 shares authorized; 14,992,018 shares issued as of December 31, 2016		150		—
Successor paid-in capital		190,621		—
Accumulated deficit		(5,296)		(2,130,271)
Successor accumulated other comprehensive income		73		—
Total shareholders' equity (deficit)	$	185,548	$	(915,121)
Total liabilities and shareholders' equity (deficit)	$	291,686	$	517,725

See accompanying notes to consolidated financial statements.

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

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash flows from operating activities				
Net income (loss)	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Non-cash reorganization items	—	(1,178,302)	—	—
Depreciation, depletion and amortization	11,652	33,582	334,479	300,299
Impairments	—	—	1,397,424	791,809
Accretion of firm transportation obligation	—	317	942	1,301
Derivative contracts:				
Net losses (gains)	16,622	8,333	(71,247)	(162,212)
Cash settlements, net	384	48,008	138,169	(7,424)
Deferred income tax benefit	—	—	(4,712)	(135,227)
Loss (gain) on sales of assets, net	49	(1,261)	(41,335)	(120,769)
Non-cash exploration expense	—	6,038	5,759	10,346
Non-cash interest expense	226	22,189	4,749	4,197
Share-based compensation (equity-classified)	81	1,511	4,540	3,627
Other, net	21	(13)	13	94
Changes in operating assets and liabilities:				
Accounts receivable, net	10,791	12,273	137,854	(20,169)
Accounts payable and accrued expenses	(3,887)	22,469	(152,553)	27,362
Other assets and liabilities	131	501	(1,818)	(918)
Net cash provided by operating activities	30,774	30,247	169,303	282,724
Cash flows from investing activities				
Capital expenditures	(4,812)	(15,359)	(364,844)	(774,139)
Receipts to settle working capital adjustments assumed in acquisition, net	—	—	—	33,712
Proceeds from sales of assets, net	—	224	85,189	313,933
Other, net	(104)	1,186	—	—
Net cash used in investing activities	(4,916)	(13,949)	(279,655)	(426,494)
Cash flows from financing activities				
Proceeds from credit facility borrowings	—	75,350	233,000	412,000
Repayment of credit facility borrowings	(50,350)	(119,121)	(98,000)	(583,000)
Proceeds from the issuance of preferred stock, net	—	—	—	313,330
Payments to induce conversion of preferred stock	—	—	—	(4,256)
Debt issuance costs paid	—	(3,011)	(744)	(151)
Proceeds received from rights offering, net	—	49,943	—	—
Dividends paid on preferred stock	—	—	(18,201)	(12,803)
Other, net	(161)	—	—	1,428
Net cash (used in) provided by financing activities	(50,511)	3,161	116,055	126,548
Net (decrease) increase in cash and cash equivalents	(24,653)	19,459	5,703	(17,222)
Cash and cash equivalents - beginning of period	31,414	11,955	6,252	23,474
Cash and cash equivalents - end of period	$ 6,761	$ 31,414	$ 11,955	$ 6,252
Supplemental disclosures:				
Cash paid for interest (net of amounts capitalized)	$ 598	$ 4,331	$ 86,226	$ 84,797
Cash paid for income taxes (net of refunds)	$ (7)	$ (35)	$ (714)	$ 3,612
Cash paid for reorganization items, net	$ 525	$ 30,990	$ —	$ —
Non-cash investing and financing activities:				
Common stock issued in exchange for liabilities	$ —	$ 140,952	$ —	$ —
Changes in accrued liabilities related to capital expenditures	$ 997	$ (11,301)	$ (55,660)	$ 24,715
Derivatives settled to reduce outstanding debt	$ —	$ 51,979	$ —	$ —

See accompanying notes to consolidated financial statements.

PENN VIRGINIA CORPORATION
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, 2013 (Predecessor)	65,307	$ 1,150	$ 466	$ 891,351	$ (104,180)	$ 2,792	$ 267	$ (3,042)	$ 788,804
Net loss	—	—	—	—	(409,592)	—	—	—	(409,592)
Issuance of common stock	—	3,250		310,080	—	—	—	—	313,330
Conversion of preferred stock	5,926	(356)	59	297	—	—	—	—	—
Payments to induce conversion of preferred stock	—	—	—	—	(4,256)	—	—	—	(4,256)
Dividends declared on preferred stock ($600.00 and $348.33 per Series A and Series B preferred share, respectively)	—	—	—	—	(17,148)	—	—	—	(17,148)
Share-based compensation	15	—	1	3,626	—	—	—	—	3,627
Deferred compensation	—	—	—	—	—	419	—	(303)	116
Exercise of stock options	257	—	3	1,425	—	—	—	—	1,428
Restricted stock unit vesting	64	—	—	(474)	—	—	—	—	(474)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	(18)	—	(18)
Balance as of December 31, 2014 (Predecessor)	71,569	4,044	529	1,206,305	(535,176)	3,211	249	(3,345)	675,817
Net loss	—	—	—	—	(1,582,961)	—	—	—	(1,582,961)
Conversion of preferred stock	9,414	(898)	94	804	—	—	—	—	—
Dividends declared on preferred stock ($300.00 and $300.00 per Series A and Series B preferred share, respectively)	—	—	—	—	(12,134)	—	—	—	(12,134)
Share-based compensation	195	—	4	4,536	—	—	—	—	4,540
Deferred compensation	2	—	—	—	—	229	—	(229)	—
Restricted stock unit vesting	73	—	1	(557)	—	—	—	—	(556)
Change in pension and postretirement benefit obligations	—	—	—	—	—	—	173	—	173
Balance as of December 31, 2015 (Predecessor)	81,253	3,146	628	1,211,088	(2,130,271)	3,440	422	(3,574)	(915,121)
Net income	—	—	—	—	1,054,602	—	—	—	1,054,602
Share-based compensation	—	—	—	1,511	—	—	—	—	1,511
All other changes	6,965	(1,266)	69	1,198	—	—	(39)	—	(38)
Balance, September 12, 2016 (Predecessor)	88,218	$ 1,880	$ 697	$ 1,213,797	$ (1,075,669)	$ 3,440	$ 383	$ (3,574)	$ 140,954
Cancellation of Predecessor equity	(88,218)	(1,880)	(697)	(1,213,797)	1,075,669	(3,440)	(383)	3,574	(140,954)
Balance, September 12, 2016 (Predecessor)	—	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Issuance of Successor common stock - Rights Offering	7,634	$ —	$ 76	$ 49,867	$ —	$ —	$ —	$ —	$ 49,943
Issuance of Successor common stock - Backstop Fee	473	—	5	9,054	—	—	—	—	9,059
Issuance of Successor common stock - exchange of claims	6,885	—	69	131,824	—	—	—	—	131,893
Balance, September 12, 2016 (Successor)	14,992	—	150	190,745	—	—	—	—	190,895
Net loss	—	—	—	—	(5,296)	—	—	—	(5,296)
Share-based compensation	—	—	—	81	—	—	—	—	81
All other changes	—	—	—	(205)	—	—	73	—	(132)
Balance as of December 31, 2016	14,992	$ —	$ 150	$ 190,621	$ (5,296)	$ —	$ 73	$ —	$ 185,548

See accompanying notes to consolidated financial statements.

1. Nature of Operations

Penn Virginia Corporation (together with its consolidated subsidiaries unless the context otherwise requires, "Penn Virginia," the "Company," "we," "us" or "our") is an independent oil and gas company engaged in the onshore exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist primarily of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in South Texas. Our operations are substantially concentrated with over 90 percent of our production, revenues and capital expenditures attributable to this region. We also have less significant operations in Oklahoma, primarily consisting of non-operated properties in the Granite Wash. In August 2016, we terminated our remaining operations in the Marcellus Shale in Pennsylvania and are currently in the process of remediating the sites of our former wells in that region.

2. Basis of Presentation

Comparability of Financial Statements to Prior Periods

As discussed in further detail in Note 5 below, we have adopted and applied the relevant guidance provided in accounting principles generally accepted in the United States of America ("GAAP") with respect to the accounting and financial statement disclosures for entities that have emerged from bankruptcy proceedings ("Fresh Start Accounting"). Accordingly, our Consolidated Financial Statements and Notes after September 12, 2016, are not comparable to the Consolidated Financial Statements and Notes through that date. To facilitate our financial statement presentations, we refer to the reorganized company in these Consolidated Financial Statements and Notes as the "Successor" for periods subsequent to September 12, 2016, and the "Predecessor" for periods prior to September 13, 2016. Furthermore, our Consolidated Financial Statements and Notes have been presented with a "black line" division to delineate the lack of comparability between the Predecessor and Successor. In addition, we have adopted the full cost method of accounting for our oil and gas properties effective with our adoption of Fresh Start Accounting. Accordingly, our results of operations and financial position for the Successor periods will be substantially different from our historic trends.

We have applied the relevant guidance provided in GAAP with respect to the accounting and financial statement disclosures for entities that have filed petitions with the bankruptcy court and expect to reorganize as going concerns in preparing our Consolidated Financial Statements and Notes through the period ended September 12, 2016, or Predecessor periods. That guidance requires that, for periods subsequent to our bankruptcy filing on May 12, 2016, or post-petition periods, certain transactions and events that were directly related to our reorganization be distinguished from our normal business operations. Accordingly, certain revenues, expenses, realized gains and losses and provisions that were realized or incurred in connection with the bankruptcy proceedings have been included in "Reorganization items, net" in our Consolidated Statement of Operations for the period ended September 12, 2016. In addition, certain liabilities and other obligations incurred prior to May 12, 2016, or pre-petition periods, have been classified in "Liabilities subject to compromise" on our Predecessor Consolidated Balance Sheet through September 12, 2016. Further detail for our "Reorganization items, net" and "Liabilities subject to compromise" are provided in Note 5 below.

Going Concern Presumption

Our Consolidated Financial Statements for the Successor period have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business.

Subsequent Events

Management has evaluated all of our activities through the issuance date of our Consolidated Financial Statements and has concluded that no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes thereto.

Recently Adopted Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU")2016–09, *Improvements to Employee Share-based Payment Accounting* ("ASU 2016–09"), which simplifies the accounting for share-based compensation. The areas for simplification that are applicable to publicly-held companies are as follows: (i) Accounting for Income Taxes, (ii) Classification of Excess Tax Benefits on the Statement of Cash Flows, (iii) Forfeitures, (iv) Minimum Statutory Tax Withholding Requirements and (v) Classification of Employee Taxes Paid on the Statement of Cash Flows when an employer withholds shares for tax-withholding purposes. The effective date of ASU 2016–09 is January 1, 2017, with early adoption permitted. We adopted ASU 2016–09 on September 12, 2016 effective upon our emergence from bankruptcy. The adoption of ASU 2016–09 did not have a significant impact on our Consolidated Financial Statements and Notes.

Recently Issued Accounting Pronouncements Pending Adoption

In June 2016, the FASB issued ASU 2016–13, *Measurement of Credit Losses on Financial Instruments* (“ASU 2016–13”), which changes the recognition model for the impairment of financial instruments, including accounts receivable, loans and held-to-maturity debt securities, among others. ASU 2016–13 is required to be adopted using the modified retrospective method by January 1, 2020, with early adoption permitted for fiscal periods beginning after December 15, 2018. In contrast to current guidance, which considers current information and events and utilizes a probable threshold, (an “incurred loss” model), ASU 2016–13 mandates an “expected loss” model. The expected loss model: (i) estimates the risk of loss even when risk is remote, (ii) estimates losses over the contractual life, (iii) considers past events, current conditions and reasonable supported forecasts and (iv) has no recognition threshold. ASU 2016–13 will have applicability to our accounts receivable portfolio, particularly those receivables attributable to our joint interest partners. At this time, we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures; however, we are currently in the early stages of evaluating the requirements and the period for which we will adopt the standard.

In February 2016, the FASB issued ASU 2016–02, *Leases* (“ASU 2016–02”), which will require organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by those leases with terms of more than twelve months. Consistent with current GAAP, the recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee primarily will depend on its classification as a finance or operating lease. ASU 2016–02 also will require disclosures regarding the amount, timing, and uncertainty of cash flows arising from leases. The effective date of ASU 2016–02 is January 1, 2019, with early adoption permitted. We believe that ASU 2016–02 will likely be applicable to our oil and natural gas gathering commitment arrangements as described in Note 16, our existing leases for office facilities and certain office equipment and potentially to certain drilling rig and completion contracts with terms in excess of twelve months to the extent we may have such contracts in the future. Our oil and natural gas gathering arrangements are fairly complex and involve multiple elements that could be construed as leases. Accordingly, we are continuing to evaluate the effect that ASU 2016–02 will have on our Consolidated Financial Statements and related disclosures as well as the period for which we will adopt the standard, however, at this time, we believe that we will likely adopt ASU 2016–02 in 2019.

In May 2014, the FASB issued ASU 2014–09, *Revenues from Contracts with Customers* (“ASU 2014–09”), which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014–09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method upon adoption. While traditional commodity sales transactions, property conveyances and joint interest arrangements in the oil and gas industry are not expected to be significantly impacted by ASU 2014–09, natural gas imbalances and other non-product revenues, including our ancillary marketing, gathering and transportation and water service revenues could be affected. Accordingly, we are continuing to evaluate the effect that ASU 2014–09 will have on our Consolidated Financial Statements and related disclosures, with a more focused analysis on these other revenue sources, which we do not believe are significant. We are also continuing to monitor developments regarding ASU 2014–09 that are unique to our industry. We fully expect to adopt ASU 2014–09 in 2018.

3. 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 GAAP 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 Predecessor 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 in 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 commodity prices and interest rates.

Oil and Gas Properties

We have adopted the full cost method of accounting for our oil and gas properties effective with our adoption of Fresh Start Accounting. Under this method, all productive and nonproductive costs incurred in the exploration, development and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical, or seismic, drilling, completion and equipment costs. Internal costs incurred that are directly attributable to exploration, development and acquisition activities undertaken by us for our own account, and which are not attributable to production, general corporate overhead or similar activities are also capitalized. Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized as a component of depreciation, depletion and amortization ("DD&A").

Unproved properties not being amortized include unevaluated leasehold costs and associated capitalized interest. These costs are reviewed quarterly to determine whether or not and to what extent proved reserves have been assigned to a property or if an impairment has occurred due to lease expirations, general economic conditions and other factors, in which case the related costs along with associated capitalized interest are reclassified to the proved oil and gas properties subject to DD&A.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated discounted future net revenues from proved properties adjusted for costs excluded from amortization and related income taxes (a "Ceiling Test"). The estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development.

For the periods prior to the Effective Date, we applied the successful efforts method of accounting for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs were capitalized. Seismic costs, delay rentals and costs to drill exploratory wells that did not find proved reserves were expensed as oil and gas exploration. We carried the costs of exploratory wells as assets if the wells had found a sufficient quantity of reserves to justify its completion as a producing well and as long as we were making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain projects, it may have taken us more than one year to evaluate the future potential of the exploratory well and make determinations of their economic viability. Our ability to move forward on projects was dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which was beyond our control. In such cases, exploratory well costs remained suspended as long as we were actively pursuing access to the necessary facilities or receiving such permits and approvals and believed that they would be obtained. We assessed the status of suspended exploratory well costs on a quarterly basis.

Depreciation, Depletion and Amortization

DD&A of our oil and gas properties is computed using the units-of-production method. We apply this method by multiplying the unamortized cost of our proved oil and gas properties, net of estimated salvage plus future development costs, by a rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period.

DD&A of our proved properties while we applied the successful efforts method during the Predecessor periods was computed using the units-of-production method. Historically, we adjusted our depletion rate throughout the year as new data became available and in the fourth quarter based on our year-end reserve report through December 31, 2015.

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 Assets

While we applied the successful efforts method of accounting for our oil and gas properties during the Predecessor periods, we reviewed our assets for impairment when events or circumstances indicated a possible decline in the recoverability of the carrying value of the properties. If the carrying value of the asset was determined to be impaired, we reduced the asset to its fair value. Fair value may have been 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 were based on management's expectations for the future and included 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 reviewed oil and gas properties for impairment periodically when events and circumstances indicated 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 estimated the future cash flows expected in connection with the properties and compared such future cash flows to the carrying amounts of the properties to determine if the carrying amounts were recoverable. Performing the impairment evaluations required use of judgments and estimates since the results were dependent on future events. Such events included estimates of proved and unproved reserves, future commodity prices, the timing of future production, capital expenditures and intent to develop properties, among others.

The costs of unproved leaseholds, including associated interest costs for the period activities were in progress to bring projects to their intended use, were capitalized pending the results of exploration efforts. Unproved properties whose acquisition costs were insignificant to total oil and gas properties were amortized in the aggregate over the lesser of five years or the average remaining lease term and the amortization was charged to exploration expense. We assessed unproved properties whose acquisition costs were relatively significant, if any, for impairment on a stand-alone basis. As exploration work progressed and the reserves on properties were proved, capitalized costs of these properties became subject to depreciation and depletion. If the exploration work was unsuccessful, the capitalized costs of the properties related to the unsuccessful work was charged to exploration expense. The timing of any write-downs of any significant unproved properties depended 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 in our Consolidated Statements of Operations.

Income Taxes

We recognize deferred tax assets and liabilities 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 assets and liabilities 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.

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.

4. Bankruptcy Proceedings and Emergence

On May 12, 2016 (the "Petition Date"), we and eight of our subsidiaries (the "Chapter 11 Subsidiaries") filed voluntary petitions (*In re Penn Virginia Corporation, et al, Case No. 16-32395*) seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Eastern District of Virginia (the "Bankruptcy Court").

On August 11, 2016 (the "Confirmation Date"), the Bankruptcy Court confirmed our Second Amended Joint Chapter 11 Plan of Reorganization of Penn Virginia Corporation and its Debtor Affiliates (the "Plan"), and we subsequently emerged from bankruptcy on September 12, 2016 (the "Effective Date").

Debtors-In-Possession. From the Petition Date through the Effective Date, we and the Chapter 11 Subsidiaries operated our business as debtors-in-possession in accordance with the applicable provisions of the Bankruptcy Code. The Bankruptcy Court granted all "first day" motions filed by us and the Chapter 11 Subsidiaries, which were designed primarily to minimize the impact of the bankruptcy proceedings on our normal day-to-day operations, our customers, regulatory agencies, including taxing authorities, and employees. As a result, we were able to conduct normal business activities and pay all associated obligations for the post-petition period and we were also authorized to pay and have paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, amounts due to taxing authorities for production and other related taxes and funds belonging to third parties, including royalty and working interest holders.

Pre-Petition Agreements. Immediately prior to the Petition Date, the holders (the "Ad Hoc Committee") of approximately 86 percent of the $1,075 million principal amount of our 7.25% Senior Notes due 2019 (the "2019 Senior Notes") and 8.50% Senior Notes due 2020 (the "2020 Senior Notes" and, together with the 2019 Senior Notes, the "Senior Notes") agreed to a restructuring support agreement (the "RSA") that set forth the general framework of the Plan and the timeline for the bankruptcy proceedings. In addition, we entered into a backstop commitment agreement (the "Backstop Commitment Agreement") with the parties thereto (collectively, the "Backstop Parties"), pursuant to which the Backstop Parties committed to provide a $50 million commitment to backstop a rights offering (the "Rights Offering") that was conducted in connection with the Plan.

Plan of Reorganization. Pursuant to the terms of the Plan, which was supported by us, the holders (the "RBL Lenders") of 100 percent of the claims attributable to our pre-petition credit agreement (as amended, the "RBL"), the Ad Hoc Committee and the Official Committee of Unsecured Claimholders (the "UCC"), the following transactions were completed subsequent to the Confirmation Date and prior to or at the Effective Date:

- the approximately $1,122 million of indebtedness, including accrued interest, attributable to our Senior Notes and certain other unsecured claims were exchanged for 6,069,074 shares representing 41 percent of the Successor's common stock ("New Common Stock");
- a total of $50 million of proceeds were received on the Effective Date from the Rights Offering resulting in the issuance of 7,633,588 shares representing 51 percent of New Common Stock to holders of claims arising under the Senior Notes, certain holders of general unsecured claims and to the Backstop Parties;
- the Backstop Parties received a backstop fee comprised of 472,902 shares representing three percent of New Common Stock;
- an additional 816,454 shares representing five percent of New Common Stock were authorized for disputed general unsecured claims and non-accredited investor holders of the Senior Notes and subsequently, 749,600 shares of New Common Stock were reserved for issuance under a new management incentive plan;

- on the Effective Date, we entered into a shareholders agreement and a registration rights agreement and amended our articles of incorporation and bylaws for the authorization of the New Common Stock and to provide customary registration rights thereunder, among other corporate governance actions;
- holders of claims arising under the RBL were paid in full from cash on hand, $75.4 million from borrowings under our new credit agreement (the “Credit Facility”) (see Note 11 below) and proceeds from the Rights Offering;
- the debtor-in-possession credit facility (the “DIP Facility”), under which there were no outstanding borrowings at any time from the Petition Date through the Effective Date, was canceled and less than $0.1 million in fees were paid in full in cash;
- certain other priority claims were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditor claim-holders;
- a cash reserve of $2.7 million was established for certain other secured, priority or convenience claims pending resolution as of the Effective Date;
- an escrow account for professional service fees attributable to our advisers and those of the UCC was funded by us with cash of $14.6 million, and we paid $7.2 million for professional fees and expenses on behalf of the RBL Lenders, the Ad Hoc Committee and the indenture trustee for the Senior Notes;
- on the Effective Date, our previous interim Chief Executive Officer, Edward B. Cloues, resigned and each member of our board of directors resigned and was replaced by new board members: Darin G. Holderness, CPA, Marc McCarthy and Harry Quarls and, in October 2016, Jerry R. Shuyler;
- our Predecessor preferred stock and common stock was canceled, extinguished and discharged; and
- all of our Predecessor share-based compensation plans and supplemental employee retirement plan (the “SERP”) entitlements were canceled.

While our emergence from bankruptcy is effectively complete, certain administrative and claims resolution activities will continue under the authority of the Bankruptcy Court until complete. As of March 10, 2017, certain claims, including secured tax and other priority, administrative and convenience claims were still in the process of resolution. While most of these matters are unsecured claims for which shares of New Common Stock have been allocated, certain of these matters must be settled with cash payments. As of December 31, 2016, we had $3.9 million reserved for outstanding claims to be potentially settled in cash. This reserve is included as a component of “Accounts payable and accrued liabilities” on our Consolidated Balance Sheet.

5. Fresh Start Accounting

We adopted Fresh Start Accounting on the Effective Date in connection with our emergence from bankruptcy. As referenced below, our reorganization value of $334.0 million, immediately prior to emergence was substantially less than our post-petition liabilities and allowed claims. Furthermore and in connection with our reorganization, we experienced a change in control as the outstanding common and preferred shares of the Predecessor were canceled and substantially all of the New Common Stock was issued to the Predecessor’s creditors, primarily former holders of our Senior Notes. Accordingly, the holders of the Predecessor’s common and preferred shares effectively received no shares of the Successor. The adoption of Fresh Start Accounting results in a new reporting entity, the Successor, for financial reporting purposes. The presentation is analogous to that of a new business entity such that the Successor is presented with no beginning retained earnings or deficit on the Effective Date.

Reorganization Value

Reorganization value represents the fair value of the Successor's total assets prior to the consideration of liabilities and is intended to approximate the amount a willing buyer would pay for the assets immediately after a restructuring. The reorganization value, which was derived from the Successor's enterprise value, was allocated to our individual assets based on their estimated fair values.

Enterprise value represents the estimated fair value of an entity's long term debt and shareholders' equity. The Successor's enterprise value, as approved by the Bankruptcy Court in support of the Plan, was estimated to be within a range of $218 million to $382 million with a mid-point value of $300 million. Based on the estimates and assumptions utilized in our Fresh Start Accounting process, we estimated the Successor's enterprise value to be approximately $266.2 million after the consideration of cash and cash equivalents on hand at the Effective Date.

The following table reconciles the enterprise value, net of cash and cash equivalents, to the estimated fair value of our Successor common stock as of the Effective Date:

Enterprise value	$	234,831
Plus: Cash and cash equivalents		31,414
Less: Fair value of debt		(75,350)
Fair value of Successor common stock	$	190,895
Shares outstanding as of September 12, 2016		14,992,018
Per share value	$	12.73

The following table reconciles the enterprise value to the reorganization value of our Successor assets as of the Effective Date:

Enterprise value	$	234,831
Plus: Cash and cash equivalents		31,414
Plus: Current liabilities		54,171
Plus: Noncurrent liabilities excluding long-term debt		13,558
Reorganization value	$	333,974

Valuation Process

Our valuation analysis was prepared with the assistance of an independent third-party consultant utilizing reserve information prepared by our independent reserve engineers, internal development plans and schedules, other internal financial information and projections and the application of standard valuation techniques including risked net asset value analysis and comparable public company metrics.

Our principal assets include the Successor's oil and gas properties. We determined the fair value of our oil and gas properties based on the discounted cash flows expected to be generated from these assets. Our analyses were based on market conditions and reserves in place as confirmed by our independent petroleum engineers. The proved reserves were segregated into various geographic regions, including sub-regions within the Eagle Ford where a substantial portion of our assets are located, for which separate risk factors were determined based on geological characteristics. Due to the limited drilling plans that we had in place, proved undeveloped locations were risked accordingly. Future cash flows were estimated by using NYMEX forward prices for West Texas Intermediate crude oil and Henry Hub natural gas with inflation adjustments applied to periods beyond a five-year horizon. These prices were adjusted for differentials realized by us for location and product quality. Gathering and transportation costs were estimated based on agreements that we have in place and development and operating costs were based on our most recent experience and adjusted for inflation in future years. The risk-adjusted after-tax cash flows were discounted at a rate of 13.5%. This rate was determined from a weighted-average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. Plugging and abandonment costs were also identified and measured in this process in order to determine the fair value of the Successor's AROs attributable to our proved developed reserves on the Effective Date. Based on this valuation process, we determined fair values of $121.9 million for our proved reserves and $2.7 million for the related AROs.

With respect to the valuation of our undeveloped acreage, we segregated our current lease holdings in the Eagle Ford into prospect regions in which we have significant developed acreage and those in which we have not yet initiated any significant drilling activity. For those prospects within previously developed regions, we applied a multiple based on recent transactions involving acreage deemed comparable to our acreage for each targeted formation. Based on this valuation process, we determined a fair value of $92.5 million for our undeveloped acreage within previously developed regions of the Eagle Ford. For those lease holdings in other areas of the Eagle Ford, we disregarded those prospects for which lease expirations were to occur during 2016 as well as those for which future drilling was considered uneconomical at then current commodity prices. A reduced multiple was then applied to this adjusted undeveloped acreage consistent with recent transactions for acreage deemed comparable to our acreage resulting in a fair value of $8.3 million. We attributed no value to our limited undeveloped lease holdings in all areas other than the Eagle Ford.

Our remaining equipment and other fixed assets were valued at $ 26.7 million primarily using a cost approach that incorporated depreciation and obsolescence to the extent applicable on an asset-by-asset basis. The most significant of these assets is our water facility in South Texas which is integral to our regional operations. Accordingly, this asset, for which we determined a fair value of $23.4 million, is included in our full cost pool for purposes of determining our DD&A attributable to our oil and gas production. Certain assets, particularly personal property including office equipment and vehicles, among others, were valued based on market data for comparable assets to the extent such information was available.

The remaining reorganization value is attributable to certain natural gas imbalance receivables, cash and cash equivalents, working capital assets including accounts receivable, prepaid items, current derivative assets and debt issuance costs. Our natural gas imbalance receivables, which are fully attributable to our Mid-Continent operations in the Granite Wash, were valued using NYMEX spot prices for Henry Hub natural gas adjusted for basis differentials for transportation. Our accounts receivable, including amounts receivable from our joint venture partners, were subjected to analysis on an individual basis and reserved to the extent we believe was appropriate. Collectively, these remaining assets, including our current derivative assets which are marked-to-market on a monthly basis, are stated at their fair values on the Effective Date. The reorganization value also includes $3.0 million of issuance costs attributable to the Credit Facility under which we initially borrowed $75.4 million. This amount has been capitalized in accordance with GAAP as it represents costs attributable to the access to credit over the term of the Credit Facility.

Our liabilities on the Effective Date include the aforementioned borrowings under the Credit Facility, working capital liabilities including accounts payable and accrued liabilities, a reserve for certain litigation matters, pension and health care obligations attributable to certain retirees, AROs, and derivative liabilities. As the Credit Facility is current and is a variable-rate financial instrument, it is stated at its fair value. Our working capital liabilities and litigation reserve are ordinary course obligations and their carrying amounts approximate their fair values. We revalued our retiree obligations based on data from our independent actuaries and they have been stated at their fair values. The AROs were valued in connection with the valuation process attributable to our oil and gas reserves as discussed above. Finally, our derivative liabilities have also been stated at their fair value as they are marked-to-market on a monthly basis.

Successor Balance Sheet

The following table reflects the reorganization and application of Fresh Start Accounting adjustments on our Consolidated Balance Sheet as of September 12, 2016:

	Predecessor	Reorganization Adjustments		Fresh Start Adjustments		Successor
Assets						
Current assets						
Cash and cash equivalents	$ 48,718	$ (17,304)	(1)	$ —		$ 31,414
Accounts receivable, net of allowance for doubtful accounts	35,606	4,292	(2)	—		39,898
Derivative assets	397	—		—		397
Other current assets	3,966	(832)	(3)	—		3,134
Total current assets	88,687	(13,844)		—		74,843
Property and equipment, net	309,261	—		(55,751)	(12)	253,510
Other assets	6,902	(1,281)	(4)	—		5,621
Total assets	$ 404,850	$ (15,125)		$ (55,751)		$ 333,974
Liabilities and Shareholders' Deficit						
Current liabilities						
Accounts payable and accrued liabilities	$ 77,151	$ (21,166)	(5)	$ (3,455)	(13)	$ 52,530
Derivative liabilities	1,641	—		—		1,641
Current maturities of long-term debt	113,653	(113,653)	(6)	—		—
Total current liabilities	192,445	(134,819)		(3,455)		54,171
Other liabilities	84,953	100	(5)	(80,615)	(14)	4,438
Derivative liabilities	9,120	—		—		9,120
Long-term debt	—	75,350	(7)	—		75,350
Liabilities subject to compromise	1,154,163	(1,154,163)	(8)	—		—
Shareholders' equity (deficit)						
Preferred stock (Predecessor)	1,880	(1,880)	(9)	—		—
Common stock (Predecessor)	697	(697)	(9)	—		—
Paid-in capital (Predecessor)	1,213,797	(1,213,797)	(9)	—		—
Deferred compensation obligation (Predecessor)	3,440	(3,440)	(9)	—		—
Accumulated other comprehensive income (Predecessor)	383	(383)	(9)	—		—
Treasury stock (Predecessor)	(3,574)	3,574	(9)	—		—
Common stock (Successor)	—	150	(10)	—		150
Paid-in capital (Successor)	—	190,745	(10)	—		190,745
Accumulated deficit	(2,252,454)	2,224,135	(11)	28,319	(15)	—
Total shareholders' equity (deficit)	(1,035,831)	1,198,407		28,319		190,895
Total liabilities and shareholders' equity (deficit)	$ 404,850	$ (15,125)		$ (55,751)		$ 333,974

Reorganization Adjustments

1. Represents the net cash payments that occurred on the Effective Date:

Sources:		
Proceeds from the Credit Facility	$ 75,350	
Proceeds from the Rights Offering, net of issuance costs	49,943	
Total sources		$ 125,293
Uses:		
Repayment of RBL	$ 113,653	
Accrued interest payable on RBL	1,374	
DIP Facility fees	12	
Debt issue costs of the Credit Facility	3,011	
Funding of professional fee escrow account	14,575	
RBL lender professional fees and expenses	455	
Ad Hoc Committee and indenture trustee professional fees and expenses	6,782	
Payment of certain allowed claims and settlements	2,735	
Total uses		142,597
		$ (17,304)

2. Represents the reclassification of SERP assets to a current receivable from other noncurrent assets upon the cancellation of the underlying plan and the reversion of the assets to the Successor.
3. Represents the write-off of certain prepaid directors and officers tail insurance.
4. Represents the capitalization of debt issuance costs attributable to the Credit Facility, net of the reclassification of SERP assets as discussed in item (2) above.
5. Represents the payment of professional fees on behalf of the RBL Lenders, the Ad Hoc Committee and the UCC, indenture trustee fees and expenses, interest payable on the RBL as well as certain allowed claims and settlements net of the establishment of reserves and the reinstatement of certain other obligations.
6. Represents the repayment of the RBL in cash in full.
7. Represents the initial borrowings under the Credit Facility.
8. Liabilities subject to compromise were settled as follows in accordance with the Plan:

Liabilities subject to compromise prior to the Effective Date:		
Senior Notes	$ 1,075,000	
Interest on Senior Notes	47,213	
Firm transportation obligation	11,077	
Compensation – related	9,733	
Deferred compensation	4,676	
Trade accounts payable	1,487	
Litigation claims	1,092	
Other accrued liabilities	3,885	
		$ 1,154,163
Amounts settled in cash, reinstated or otherwise reserved at emergence		(3,915)
Gain on settlement of liabilities subject to compromise		$ 1,150,248

9. Represents the cancellation of our Predecessor preferred and common stock and related components of our Predecessor shareholders' deficit.
10. Represents the issuance of 14,992,018 shares of New Common Stock with a fair value of $12.73 per share.

11. Represents the cumulative impact of the reorganization adjustments described above:

Gain on settlement of of liabilities subject to compromise		$	1,150,248
Fair value of equity allocated to:			
Unsecured creditors on the Effective Date	174,477		
Unsecured creditors pending resolution on the Effective Date	10,396		
Backstop Parties in the form of a Commitment Premium	6,022		
			190,895
Cancellation of Predecessor shareholders' deficit			882,992
Net impact to Predecessor accumulated deficit		$	2,224,135

Fresh Start Adjustments

12. Represents the Fresh Start Accounting valuation adjustments applied to our oil and gas properties and other equipment.
13. Represents the accelerated recognition of the current portion of previously deferred gains on sales of assets attributable to the accounting presentation required by GAAP under the Predecessor.
14. Represents the recognition of Fresh Start Accounting adjustments to: (i) our AROs attributable to the revalued oil and gas properties and (ii) our retiree obligations based on actuarial measurements, as well as the accelerated recognition of the noncurrent portion of previously deferred gains on sales of assets attributable to the accounting presentation required by GAAP under the Predecessor.
15. Represents the cumulative impact of the Fresh Start Accounting adjustments discussed above.

Reorganization Items. As described above in Note 2, our Consolidated Statements of Operations for the period ended September 12, 2016 include "Reorganization items, net," which reflects gains recognized on the settlement of liabilities subject to compromise and costs and other expenses associated with the bankruptcy proceedings, principally professional fees, and the costs associated with the DIP Facility. These post-petition costs for professional fees, as well as administrative fees charged by the U.S. Trustee, have been reported in "Reorganization items, net" in our Consolidated Statement of Operations as described above. Similar costs that were incurred during the pre-petition periods have been reported in "General and administrative" expenses.

The following table summarizes the components included in "Reorganization items, net" in our Consolidated Statements of Operations for the period presented:

		January 1 Through September 12, 2016
Gains on the settlement of liabilities subject to compromise	$	1,150,248
Fresh start accounting adjustments		28,319
Legal and professional fees and expenses		(29,976)
Settlements attributable to contract amendments		(2,550)
DIP Facility costs and commitment fees		(170)
Write-off of prepaid directors and officers insurance		(832)
Other reorganization items		(46)
	$	1,144,993

6. Divestitures

South Texas Properties

In October 2015, we sold certain non-core Eagle Ford properties for $12.5 million net of transaction costs and customary closing adjustments. We recognized a loss of $9.5 million on this transaction.

Mid-Continent Properties

In October 2015, we sold certain properties in Oklahoma that were outside of our core Granite Wash operating region for approximately $0.1 million which represented their approximate carrying values.

East Texas Properties

In August 2015, we sold our Cotton Valley and Haynesville Shale assets in East Texas and received cash proceeds of approximately $73 million, net of transaction costs and customary closing adjustments. The effective date of the sale was May 1, 2015 and we recognized a gain of approximately $43 million. The carrying value of the net assets disposed in this transaction was $29.5 million, including oil and gas properties and other assets of $33.3 million, net of related AROs of $3.8 million. The net pre-tax operating income (loss), excluding the gain on sale and impairment charges, attributable to the East Texas assets was $1.3 million and $(27.5) million for the years ended December 31, 2015 and 2014, respectively. The net proceeds from this transaction were used to pay down a portion of our outstanding borrowings under the RBL.

Oil Gathering System Construction Rights

In July 2014, we sold the rights to construct a crude oil gathering and intermediate transportation system in South Texas to Republic Midstream, LLC ("Republic Midstream") for proceeds of $147.1 million, net of transaction costs. Concurrent with the sale, we entered into long-term agreements with Republic Midstream to provide us gathering and intermediate transportation services for a substantial portion of our South Texas crude oil and condensate production. We realized a gain of $147.1 million, of which $63.0 million was recognized upon the closing of the transaction and the remaining $84.1 million was deferred. In September 2015, the gathering agreement with Republic was amended to reduce the number of wells initially required to be connected to the pipeline system, provide for alternative transportation in areas that would not be served by the pipeline and also reduce the gathering fees. As a result of this amendment, we recognized $8.4 million of the deferred gain in September 2015. We recognized $1.7 million of the deferred gain in the Predecessor period of 2016 prior to emergence. Prior to the Effective Date, the Bankruptcy Court approved a settlement and we entered into certain amendments to the agreements with Republic (see Note 16). These actions did not impact the amortization of any gain prior to the Effective Date. In connection with our adoption of Fresh Start Accounting, we accelerated the recognition of the remaining deferred gain of $74.1 million as a Fresh Start Accounting adjustment included in Reorganization items, net in our Predecessor Statement of Operations for the 2016 period.

Mississippi Properties

In July 2014, we sold our Selma Chalk assets in Mississippi for proceeds of $67.9 million, net of transaction costs and customary closing adjustments. An impairment charge of $117.9 million was recognized in the second quarter of 2014 with respect to these assets.

Natural Gas Gathering and Gas Lift Assets

In January 2014, we sold our natural gas gathering and gas lift assets in South Texas to American Midstream Partners, LP ("AMID") for proceeds of approximately $96 million, net of transaction costs. Concurrent with the sale, we entered into a long-term agreement with AMID to provide us natural gas gathering, compression and gas lift services for a substantial portion of our South Texas natural gas production. We realized a gain of $67.3 million, of which $56.7 million was recognized upon the closing of the transaction and the remainder was deferred and was being amortized over a twenty-five year period. We recognized $0.4 million of the deferred gain in both 2015 and 2014. We recognized $0.3 million of the deferred gain in the Predecessor period of 2016 prior to our emergence from bankruptcy. In connection with our adoption of Fresh Start Accounting, we accelerated the recognition of the remaining deferred gain of $9.5 million as a Fresh Start Accounting adjustment included in Reorganization items, net in our Predecessor Statement of Operations for the 2016 period.

Other Assets

During 2014, we also received net proceeds of $2.9 million and recognized net gains of $0.2 million from the sale of various non-core oil and gas properties and tubular inventory and well materials.

7. Accounts Receivable and Major Customers

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

	Successor	Predecessor
	December 31,	
	2016	2015
Customers	$ 20,489	$ 23,481
Joint interest partners	7,238	18,381
Other	3,789	7,658
	31,516	49,520
Less: Allowance for doubtful accounts	(2,421)	(1,555)
	$ 29,095	$ 47,965

For the year ended December 31, 2016, three customers accounted for $122.7 million, or approximately 93% of our consolidated product revenues. The revenues generated from these customers during 2016 were $93.5 million, $15.7 million and $13.5 million or 71%, 12%, and 10% of the consolidated total, respectively. As of December 31, 2016, $16.7 million, or approximately 81% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2015, three customers accounted for $168.9 million, or approximately 64% of our consolidated product revenues. The revenues generated from these customers during 2015 were $74.5 million, $63.5 million and $30.9 million, or approximately 28%, 24% and 12% of the consolidated total, respectively. As of December 31, 2015, $21.1 million, or approximately 90% 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.

8. Derivative Instruments

We utilize derivative instruments to mitigate our financial exposure to crude oil and natural gas price volatility. Our derivative instruments are not formally designated as hedges in the context of U.S. GAAP.

Commodity Derivatives

We typically 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 collar contract.

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.

We terminated all of our pre-petition derivative contracts from March 2016 through May 2016 for $63.0 million and reduced our amounts outstanding under the RBL by $52.0 million. In connection with these transactions, the counterparties to the derivative contracts, which were also affiliates of lenders under the RBL, transferred the cash proceeds that were used for RBL repayments directly to the administrative agent under the RBL. Accordingly, all of these RBL repayments have been presented as non-cash financing activities in our Consolidated Statement of Cash Flows for the period January 1, 2016 through September 12, 2016.

On May 13, 2016, the Bankruptcy Court approved our motion to enter into new commodity derivative contracts. Accordingly, we hedged a substantial portion of our future crude oil production through the end of 2019, as required in the RSA, at a weighted-average price of approximately $49.12 per barrel. We are currently unhedged with respect to natural gas as well as NGL production.

The following table sets forth our commodity derivative positions as of December 31, 2016:

	Instrument	Average Volume Per Day	Weighted Average Price			Fair Value		
			Floor/Swap		Ceiling	Asset		Liability
Crude Oil:		(barrels)	($/barrel)					
First quarter 2017	Swaps	4,408	$	48.62	—	$ —	$	2,454
Second quarter 2017	Swaps	4,408	$	48.62	—	—		3,110
Third quarter 2017	Swaps	4,408	$	48.62	—	—		3,290
Fourth quarter 2017	Swaps	4,408	$	48.62	—	—		3,260
First quarter 2018	Swaps	3,476	$	49.12	—	—		2,267
Second quarter 2018	Swaps	3,476	$	49.12	—	—		2,193
Third quarter 2018	Swaps	3,476	$	49.12	—	—		2,140
Fourth quarter 2018	Swaps	3,476	$	49.12	—	—		2,091
First quarter 2019	Swaps	2,916	$	49.90	—	—		1,471
Second quarter 2019	Swaps	2,916	$	49.90	—	—		1,438
Third quarter 2019	Swaps	2,916	$	49.90	—	—		1,423
Fourth quarter 2019	Swaps	2,916	$	49.90	—	—		1,414
Settlements to be paid in subsequent period								818

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:

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Derivative gains (losses)	$ (16,622)	$ (8,333)	$ 71,247	$ 162,212

The effects of derivative gains and (losses) and cash settlements (except for those cash settlements attributable to the aforementioned termination transactions) 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 losses (gains)” and “Cash settlements, net.”

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:

		Successor		Predecessor	
		Fair Values			
		December 31, 2016		December 31, 2015	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ —	$ 12,932	$ 97,956	$ —
Commodity contracts	Derivative assets/liabilities – noncurrent	—	14,437	—	—
		$ —	$ 27,369	$ 97,956	$ —

As of December 31, 2016, we reported a commodity derivative liability of $27.4 million. The net and gross amounts for our derivative assets and liabilities are the same for both periods presented above. The contracts associated with this position are with three counterparties, all of which are investment grade financial institutions. 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. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

9. Property and Equipment

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

	Successor	Predecessor
	December 31,	
	2016	2015
Oil and gas properties:		
Proved	$ 251,083	$ 2,678,415
Unproved [1]	4,719	6,881
Total oil and gas properties	255,802	2,685,296
Other property and equipment	3,575	31,365
Total property and equipment	259,377	2,716,661
Accumulated depreciation, depletion and amortization [1]	(11,904)	(2,372,266)
	$ 247,473	$ 344,395

[1] See Note 19 for information regarding impairments to our property and equipment while we applied the successful efforts method of accounting.

As discussed in Note 3, we adopted the full cost method of accounting for oil and gas properties on the Effective Date. Our unproved property costs of $4.7 million as of December 31, 2016 have been excluded from amortization. These costs are anticipated to be included in the full cost pool for amortization in 2017. These unproved property costs, excluding capitalized interest, were incurred during the Predecessor periods and were adjusted to their fair value in connection with the application of Fresh Start Accounting. During the Successor period in 2016, we transferred $3.8 million of undeveloped leasehold costs, including capitalized interest, from unproved properties to the full cost pool due primarily to expiring acreage. We capitalized internal costs of $0.5 million and interest of less than $0.1 million during the Successor period in 2016 in accordance with our accounting policies. Average DD&A per BOE of proved oil and gas properties was $11.20 for the Successor period ended December 31, 2016, $10.04 for the Predecessor period ended September 12, 2016 and $42.22 and $37.85 for the years ended December 31, 2015 and 2014, respectively.

10. 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:

	Successor	Predecessor	
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	December 31, 2015
Balance at beginning of period	$ 2,687	$ 2,621	$ 5,890
Fresh Start Accounting adjustment	—	(754)	—
Changes in estimates	27	176	172
Liabilities incurred	—	469	110
Liabilities settled	(311)	—	—
Sale of properties	—	—	(3,932)
Accretion expense	56	175	381
Balance at end of period	$ 2,459	$ 2,687	$ 2,621

11. Long-Term Debt

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

	Successor		Predecessor	
	December 31, 2016		December 31, 2015	
	Principal	Unamortized Issuance Costs [1]	Principal	Unamortized Issuance Costs [1]
Credit facility [2]	$ 25,000		$ —	
Pre-petition credit facility [3]			170,000	
Senior notes due 2019	—	$ —	300,000	$ 3,295
Senior notes due 2020	—	—	775,000	17,322
Totals	25,000	$ —	1,245,000	$ 20,617
Less: Unamortized issuance costs	—		(20,617)	
Less: Current portion	—		(1,224,383)	
Long-term debt, net of unamortized issuance costs	$ 25,000		$ —	

[1] Issuance costs attributable to the Senior Notes were subject to an accelerated write-off in advance of our bankruptcy filing during the three months ended June 30, 2016.

[2] Issuance costs attributable to the Credit Facility, which represent costs attributable to the access to credit over the Credit Facility's contractual term, have been presented as a component of Other assets (see Note 14).

[3] Issuance costs attributable to the RBL were presented as a component of Other assets (see Note 14) prior to the accelerated write-off in advance of our bankruptcy filing during the three months ended June 30, 2016.

Credit Facility

On the Effective Date, we entered into the Credit Facility. The Credit Facility provides for a $200 million revolving commitment and has an initial borrowing base of $128 million. The Credit Facility also includes a $5.0 million sublimit for the issuance of letters of credit, of which $0.8 million were outstanding as of December 31, 2016. The Credit Facility is governed by a borrowing base calculation, which is redetermined semi-annually, and the availability under the Credit Facility may not exceed the lesser of the aggregate commitments and the borrowing base. The Credit Facility is scheduled for its initial redetermination in April 2017. After April 1, 2017, the Credit Facility lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us to pay expenses associated with our bankruptcy proceedings and for general corporate purposes including working capital. The Credit Facility matures in September 2020.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 2.00% to 3.00%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate ("LIBOR") plus an applicable margin ranging from 3.00% to 4.00%, determined based on the average availability under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on eurocurrency borrowings is payable every one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days. As of December 31, 2016, the actual interest rate on the outstanding borrowings under the Credit Facility was 3.67%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility is guaranteed by us and all of our subsidiaries (the "Guarantor Subsidiaries"). The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. The parent company has 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, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our assets.

The Credit Facility requires us to maintain (1) a minimum interest coverage ratio (adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses as defined in the Credit Facility ("EBITDAX") to adjusted interest expense), measured as of the last day of each fiscal quarter, of 3.00 to 1.00, (2) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00, and (3) a maximum leverage ratio (consolidated indebtedness to adjusted EBITDAX), measured as of the last day of each fiscal quarter, initially of 4.00 to 1.00, decreasing on December 31, 2017 to 3.75 to 1.00 and on March 31, 2018 and thereafter to 3.50 to 1.00.

The Credit Facility also contains customary affirmative and negative covenants, including as to compliance with laws (including environmental laws, ERISA and anti-corruption laws), maintenance of required insurance, delivery of quarterly and annual financial statements, oil and gas engineering reports and budgets, maintenance and operation of property (including oil and gas properties), restrictions on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

As of December 31, 2016, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of these covenants.

Pre-Petition Credit Facility

As described in Notes 4 and 5, our principal and interest obligations outstanding under the RBL as well as certain associated fees and expenses were satisfied in cash in full on the Effective Date. These obligations were funded from a combination of cash on hand, proceeds from the Rights Offering and proceeds from initial borrowings under the Credit Facility.

2019 Senior Notes and 2020 Senior Notes

The Senior Notes were included in “Liabilities subject to compromise” on the Consolidated Balance Sheet of the Predecessor as of September 12, 2016 (see Note 5) and were included in “Current liabilities” as of December 31, 2015. As described in Notes 4 and 5, the Senior Notes were canceled upon our emergence from bankruptcy.

12. Income Taxes

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

	Successor	Predecessor		
	Period From September 13, 2016	Period From January 1, 2016	Year Ended December 31,	
	Through December 31, 2016	Through September 12, 2016	2015	2014
Current income taxes (benefit)				
Federal	$ —	$ —	$ (660)	$ 2,045
State	—	—	1	1,504
	—	—	(659)	3,549
Deferred income tax benefit				
Federal	—	—	(261)	(130,693)
State	—	—	(4,451)	(4,534)
	—	—	(4,712)	(135,227)
	$ —	$ —	$ (5,371)	$ (131,678)

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

	Successor		Predecessor					
	Period From September 13, 2016		Period From January 1, 2016		Year Ended December 31,			
	Through December 31, 2016		Through September 12, 2016		2015		2014	
Computed at federal statutory rate	$ (1,854)	35.0 %	$ 369,111	35.0 %	$ (555,916)	35.0 %	$ (189,445)	35.0 %
State income taxes, net of federal income tax benefit	197	(3.7)%	1,989	0.2 %	(4,438)	0.3 %	(3,556)	0.6 %
Change in valuation allowance	1,657	(31.3)%	(384,692)	(36.5)%	554,879	(35.0)%	61,104	(11.3)%
Reorganization adjustments	—	— %	13,572	1.3 %	—	— %	—	— %
Other, net	—	— %	20	— %	104	— %	219	— %
	$ —	— %	$ —	— %	$ (5,371)	0.3 %	$ (131,678)	24.3 %

The following table summarizes the principal components of our deferred income tax assets and liabilities as of the dates presented:

	Successor	Predecessor
	December 31,	
	2016	2015
Deferred tax assets:		
Property and equipment	$ 183,303	$ 417,535
Pension and postretirement benefits	710	2,276
Share-based compensation	28	7,393
Net operating loss (“NOL”) carryforwards	87,622	222,971
Fair value of derivative instruments	9,579	—
Deferred gains	—	30,382
Other	7,166	16,637
	288,408	697,194
Less: Valuation allowance	(288,408)	(662,909)
Total net deferred tax assets	—	34,285
Deferred tax liabilities:		
Fair value of derivative instruments	—	34,285
Total net deferred tax liabilities	—	34,285
Net deferred tax liabilities	$ —	$ —

As of December 31, 2016, we had federal NOL carryforwards of approximately $120.3 million, which, if not utilized, expire between 2032 and 2036, and tax-effected state NOL carryforwards of approximately $69.6 million, which expire between 2024 and 2036. Because of the change in ownership provisions of the Tax Reform Act of 1986, use of a portion of our federal and state NOL may be limited in future periods.

As of December 31, 2015, we carried a valuation allowance against our federal and state deferred tax assets of $662.9 million. We incurred a pre-tax loss in 2015 which, when aggregated with the prior two years, resulted in a pre-tax loss for the three year period ended December 31, 2015. We considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. Due to the reorganization and subsequent emergence from bankruptcy, our NOL carryforwards were reduced under Internal Revenue Code Section 108(b), as well as a corresponding decrease in the valuation allowance of $374.5 million which resulted in an ending balance of $288.4 million as of December 31, 2016. The amount of deferred tax asset considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as our projections for growth.

We had no liability for unrecognized tax benefits as of December 31, 2016 and 2015. There were no interest and penalty charges recognized during the years ended December 31, 2016, 2015 and 2014. Tax years from 2012 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

13. Exit Activities

We have committed to a number of actions, or exit activities, consistent with our current business plans for which we have continuing financial commitments. The most significant of these activities are attributable to an overall reduction in the scope and scale of our organization and require payments to satisfy obligations associated with the underlying commitments. The following summarizes our most significant exit activities.

Reductions in Force

In connection with efforts to reduce our administrative costs, we took certain actions to reduce our total employee headcount. In 2016, we reduced our total employee headcount by 53 employees. We paid a total of $2.1 million, including $1.4 million in severance and termination benefits and $0.7 million in retention bonuses during the year ended December 31, 2016.

The costs associated with these reduction-in-force and retention actions are included as a component of our "General and administrative" expenses in our Consolidated Statements of Operations. The related obligations are included in "Accounts payable and accrued liabilities" on our Consolidated Balance Sheet.

Drilling Rig Termination

In connection with the suspension of our 2016 drilling program in the Eagle Ford, we terminated our one remaining drilling rig contract and incurred $1.7 million in early termination charges. As this obligation represented a pre-petition liability of the Predecessor, it was included in "Reorganization items, net" in our Consolidated Statements of Operations.

Firm Transportation Obligation

We had a contractual obligation with a carrying value of $10.8 million for certain firm transportation capacity in the Appalachian region that was scheduled to expire in 2022 and, as a result of the sale of our natural gas assets in this region in 2012, we no longer had production available to satisfy this commitment. We originally recognized a liability in 2012 representing this obligation for the estimated discounted future net cash outflows over the remaining term of the contract. The accretion of the obligation through the Petition Date, net of any recoveries from periodic sales of our contractual capacity, was charged as an offset to Other revenue. In connection with our emergence from bankruptcy, we rejected the underlying contract and the obligation was included in "Reorganization items, net" in our Consolidated Statements of Operations.

14. Additional Balance Sheet Detail

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

	Successor	Predecessor
	December 31,	
	2016	2015
Other current assets:		
Tubular inventory and well materials	$ 2,125	$ 2,878
Prepaid expenses	903	4,184
Other	—	42
	$ 3,028	$ 7,104
Other assets:		
Deferred issuance costs of the credit facilities [1]	$ 2,785	$ 1,572
Assets of the SERP [2]	—	4,123
Other	2,544	2,655
	$ 5,329	$ 8,350
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 9,825	$ 11,603
Drilling costs	2,479	12,074
Royalties and revenue - related	26,116	39,119
Compensation - related	2,557	9,904
Interest	55	15,531
Deferred gains on sales of assets	—	2,593
Firm transportation obligation	—	2,756
Reserve for bankruptcy claims	3,922	—
Other	4,743	9,945
	$ 49,697	$ 103,525
Other liabilities:		
Deferred gains on sales of assets	$ —	$ 82,943
Firm transportation obligation	—	10,705
Asset retirement obligations	2,459	2,621
Defined benefit pension obligations	1,025	1,129
Postretirement health care benefit obligations	488	731
Compensation - related	—	1,447
Deferred compensation - SERP obligations and other	—	4,434
Other	100	928
	$ 4,072	$ 104,938

[1] The balance as of December 31, 2016 includes those costs, net of amortization, attributable to the the Credit Facility. Deferred issuance costs attributable to the RBL, which represents the amounts outstanding as of December 31, 2015, were charged in full to interest expense during the three months ended June 30, 2016 in advance of our bankruptcy filing.

[2] In connection with our emergence from bankruptcy, the assets of the SERP reverted to us upon the release of claims by our employees attributable to certain deferred compensation arrangements in September 2016. The SERP assets were liquidated by the plan trustee in October 2016 and the cash value was transferred to us (See Notes 4 and 5).

15. 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, 2016, the carrying values of all of these financial instruments 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:

	Successor		Predecessor	
	December 31, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Notes due 2019 [1]	$ —	$ —	$ 40,830	$ 300,000
Senior Notes due 2020 [1]	—	—	125,473	775,000
	$ —	$ —	$ 166,303	$ 1,075,000

[1] The Senior Notes were canceled upon our emergence from bankruptcy.

Recurring Fair Value Measurements

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

	Successor			
	December 31, 2016			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Liabilities:				
Commodity derivative liabilities – current	$ (12,932)	$ —	$ (12,932)	$ —
Commodity derivative liabilities – noncurrent	(14,437)	—	(14,437)	—

	Predecessor			
	December 31, 2015			
	Fair Value	Fair Value Measurement Classification		
Description	**Measurement**	**Level 1**	**Level 2**	**Level 3**
Assets:				
Commodity derivative assets – current	$ 97,956	$ —	$ 97,956	$ —
Assets of the SERP	4,123	4,123	—	—
Liabilities:				
Deferred compensation – SERP obligation	(4,125)	(4,125)	—	—

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 any period in the years ended December 31, 2016, 2015 and 2014.

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*: During the Predecessor periods, we held various publicly traded equity securities in a Rabbi Trust as assets for funding certain deferred compensation obligations. The fair values were based on quoted market prices, which were level 1 inputs.
- *Deferred compensation - SERP obligations*: Certain of our deferred compensation obligations in the Predecessor periods were 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 were based on quoted market prices, which were 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 the Successor's net assets with respect to the application of Fresh Start Accounting. Those measurements are more fully described in Note 5. In addition, we utilize non-recurring fair value measurements with respect to the recognition and measurement of asset impairments, particularly during our Predecessor periods during which time we applied the successful efforts method to our oil and gas properties, as well as the initial determination of AROs associated with the ongoing development of new oil and gas properties.

The factors used to determine fair value for purposes of recognizing and measuring asset impairments while we applied the successful efforts method to our oil and gas properties during our Predecessor periods included, but were not limited to, estimates of proved and risk-adjusted 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 were typically not observable, we have categorized the amounts as level 3 inputs. Under the full cost method, which we have applied since the Effective Date, we apply a ceiling test determination utilizing prescribed procedures as described in Note 3. The full cost method is substantially different from the successful efforts method which relies upon fair value measurements.

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.

16. Commitments and Contingencies

The following table sets forth our significant commitments as of December 31, 2016, by category, for the next five years and thereafter:

Year	Minimum Rentals	Gathering and Intermediate Transportation	Derivatives	Other Commitments
2017	$ 264	$ 9,646	$ 12,932	$ 596
2018	190	10,376	8,691	71
2019	70	11,702	5,746	—
2020	41	12,962	—	—
2021	—	12,962	—	—
Thereafter	—	76,674	—	—
Total	$ 565	$ 134,322	$ 27,369	$ 667

Rental Commitments

Operating lease rental expense was $0.2 million, $2.4 million, $7.2 million and $8.7 million, for the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the Predecessor years ended December 31, 2015 and 2014, respectively, related primarily to field equipment, office equipment and office leases.

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Republic Midstream and Republic Midstream Marketing, LLC (“Republic Marketing” and, together with Republic Midstream, collectively, “Republic”) to provide gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in the South Texas region as well as volume capacity support for certain downstream interstate pipeline transportation.

In August 2016, the Bankruptcy Court approved a settlement with Republic and authorized the assumption of certain amended agreements with Republic (the “Amended Agreements”). We paid Republic $0.3 million in connection with the settlement which is included in “Reorganization items, net” in our Consolidated Statements of Operations.

Under the terms of the Amended Agreements, Republic is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford (the “Dedication Area”) via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party. The amended gathering agreement reduced our minimum volume commitment from 15,000 to 8,000 gross barrels of oil per day. The term of the amended gathering agreement runs through 2041, with the term of the minimum volume commitment extended from 10 to 15 years. The gathering portion of these minimum commitments are being recognized as a component of our gathering, processing and transportation expense while the intermediate transportation and pipeline support commitments are recognized as a reduction to the index-based price that we receive for crude oil sold to Republic in accordance with Amended Agreements.

Under the amended marketing agreement, we have a 10-year commitment to sell 8,000 barrels per day of crude oil to Republic, or any third party, utilizing Republic Marketing’s capacity on a certain downstream interstate pipeline.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have minimum commitments under information technology licensing, service agreements and employment 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 2016, we reduced our reserve for a litigation matter to $0.1 million from $0.9 million due to our dismissal from the subject litigation.

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, 2016, we have recorded AROs of $2.5 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.

17. Shareholders’ Equity

Preferred Stock

As discussed in Note 4, all of our Predecessor preferred stock was canceled upon our emergence from bankruptcy on the Effective Date. As of December 31, 2016, there were 5,000,000 Successor shares of preferred stock authorized with none issued or outstanding.

Common Stock

As discussed in Note 4, all our Predecessor common stock was canceled upon our emergence from bankruptcy on the Effective Date and 14,992,018 shares of New Common Stock were issued with a par value of $0.01 per share. We have a total of 45,000,000 shares authorized. We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, our Credit Facility has restrictive covenants that limit our ability to pay dividends.

Accumulated Other Comprehensive Income

Accumulated other comprehensive income and losses are entirely attributable to our pension and postretirement health care benefit obligations. The accumulated other comprehensive income, net of tax, was $0.1 million, less than $0.1 million, $0.4 million and $0.2 million as of December 31, 2016, September 12, 2016 and December 31, 2015 and 2014, respectively.

Treasury Stock

Shares of our Predecessor common stock held by the SERP and Predecessor deferred common stock units that had not been converted into Predecessor common stock were previously presented for financial reporting purposes as treasury stock carried at cost. A total of 455,689 Predecessor shares were recorded as treasury stock as of December 31, 2015. As discussed above, all of the Predecessor common stock held by the SERP and Predecessor deferred common stock units were canceled upon our emergence from bankruptcy on the Effective Date.

18. Share-Based Compensation and Other Benefit Plans

We recognize share-based compensation expense related to our share-based compensation plans as a component of “General and administrative” expense in our Consolidated Statements of Operations.

We reserved 749,600 shares of New Common Stock for issuance under the Penn Virginia Corporation Management Incentive Plan for future share-based compensation awards. A total of 107,563 shares of time-vested restricted stock units had been granted as of December 31, 2016.

In the Predecessor periods in 2016, 2015 and 2014, we had outstanding equity-classified awards in the form of stock options, restricted stock units and deferred stock units. As discussed in Notes 4 and 5, all remaining equity-classified share-based compensation awards were canceled in connection with our emergence from bankruptcy.

With the exception of our Predecessor performance-based restricted stock units (“PBRSUs”), all of our Successor and Predecessor share-based compensation awards 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 has been measured at the grant date and recognized over the applicable vesting period as a non-cash item of expense. Because the Predecessor PBRSUs were payable in cash, they were typically considered liability-classified awards and were included in “Accounts payable and accrued liabilities” (current portion) and “Other liabilities” (noncurrent portion) on the Consolidated Balance Sheets of the Predecessor. Compensation cost associated with the Predecessor PBRSUs was measured at the end of each reporting period and recognized based on the period of time that had elapsed during each of the individual performance periods.

The following tables summarize our share-based compensation expense (benefit) recognized for the periods presented:

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Equity-classified awards	$ 81	$ 1,511	$ 4,540	$ 3,627
Liability-classified awards	—	(19)	(711)	4,520
	$ 81	$ 1,492	$ 3,829	$ 8,147

Stock Options

The exercise price of all stock options granted under our Predecessor incentive compensation plans was equal to the fair value of our common stock on the date of the grant. Options could be exercised at any time after vesting and prior to ten years following the date of grant. Options vested upon terms established by the compensation and benefits committee of our board of directors (the “Committee”). Generally, options vested over a three-year period, with one-third vesting in each year.

The fair value of each option award was estimated on the date of grant using the Black-Scholes-Merton option-pricing formula. Expected volatilities were based on historical changes in the market value of our stock. Separate groups of employees that had similar historical exercise behavior were considered separately to estimate expected lives. Options granted had a maximum term of ten years. We based 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.

The ranges for the assumptions used in the Black-Scholes-Merton pricing formula for the Predecessor stock options granted in the periods presented were as follows:

	Predecessor	
	Year Ended December 31,	
	2015	2014
Expected volatility	64.6% to 69.4%	56.2% to 63.7%
Dividend yield	0.00% to 0.00%	0.00% to 0.00%
Expected life	3.5 to 4.6 years	3.5 to 4.6 years
Risk-free interest rate	0.87% to 1.54%	0.82% to 1.63%

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
Balance as of January 1, 2016 (Predecessor)	3,083,821	$ 16.05		
Granted	—	—		
Exercised	—	—		
Forfeited or expired	—	—		
Canceled	(3,083,821)	$ 16.05		
Balance as of December 31, 2016 (Successor)	—	$ —	—	$ —
Exercisable as of end of year (Successor)	—	$ —	—	$ —

The weighted-average grant-date fair value of options granted during the Predecessor years ended December 31, 2015 and 2014, respectively, was $3.15 and $7.46 per option. The total intrinsic value of options exercised during the Predecessor year ended December 31, 2014 was $2.3 million. There were no options exercised during 2015 and 2016. The total grant-date fair values of stock options that vested in Predecessor years 2015 and 2014 were $1.3 million and $1.8 million, respectively.

In connection with our emergence from bankruptcy, all stock options outstanding as of September 12, 2016 were canceled.

Common Stock

A portion of the compensation paid to certain non-employee members of our Predecessor board of directors was paid in common stock. Each share of common stock granted as compensation vested immediately upon issuance. In 2015 and 2014 respectively, we granted 195,395 and 15,501 shares of common stock to our non-employee directors at a weighted-average grant date fair value of $1.33 and $11.61 per share. No shares were granted during the Successor or Predecessor periods in 2016.

In connection with our emergence from bankruptcy, all shares granted to the non-employee members of our Predecessor board of directors as of September 12, 2016 were canceled.

Deferred Common Stock Units

A portion of the compensation paid to certain non-employee members of our Predecessor board of directors was paid in deferred common stock units. Each deferred common stock unit represented one share of common stock, vested immediately upon issuance, and was available to the holder upon termination or retirement from our board of directors. Deferred common stock units awarded to directors received all cash or other dividends we paid 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 as of January 1, 2016 (Predecessor)	447,498	$ 7.75
Granted	—	—
Converted	—	—
Canceled	(447,498)	$ 7.75
Balance as of December 31, 2016 (Successor)	—	$ —

As of December 31, 2015, our Predecessor shareholders' deficit included deferred compensation obligations of $3.4 million and corresponding amounts for treasury stock.

In connection with our emergence from bankruptcy, all deferred common stock units outstanding as of September 12, 2016 were canceled.

Time-Vested 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. The grant date fair value of our time-vested restricted stock unit awards are recognized on a straight-line basis over the applicable vesting period.

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 as of January 1, 2016 (Predecessor)	468,986	$ 6.97
Granted	107,563	23.15
Vested	—	—
Forfeited	—	—
Canceled	(468,986)	$ 6.97
Balance as of December 31, 2016 (Successor)	107,563	$ 23.15

As of December 31, 2016, we had $2.4 million of unrecognized compensation cost attributable to Successor unvested restricted stock units. We expect that cost to be recognized over a weighted-average period of 1.5 years. The Predecessor total grant-date fair values of restricted stock units that vested in 2015 and 2014 were $2.2 million and $0.6 million, respectively. No restricted stock units vested during 2016.

In connection with our emergence from bankruptcy, all outstanding restricted stock units as of September 12, 2016 were canceled.

Predecessor Performance-Based Restricted Stock Units

In May 2015, May 2014 and May 2013, we granted PBRSUs to certain executive officers. Vested PBRSUs were 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 ranged from 0% to 200% of the initial grant. The PBRSUs did not have voting rights and did not participate in dividends.

The compensation cost of the PBRSUs was 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 Predecessor PBRSUs granted in the periods presented were as follows:

	Predecessor	
	Year Ended December 31,	
	2015	2014
Expected volatility	66.5% to 97.7%	52.6% to 72.3%
Dividend yield	0.0% to 0.0%	0.0% to 0.0%
Risk-free interest rate	0.01% to 1.31%	0.02% to 1.07%

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 as of January 1, 2016 (Predecessor)	941,097	$ 9.19
Granted	—	—
Forfeited	—	—
Canceled	(941,097)	$ 9.19
Balance as of December 31, 2016 (Successor)	—	$ —

In connection with our emergence of bankruptcy, all outstanding PBRSUs as of September 12, 2016 were canceled.

Defined Contribution Plan

We maintain the Penn Virginia Corporation and Affiliated Companies Employees 401(k) Plan (the “401(k) Plan”), a defined contribution plan, which covers substantially all of our employees. We provide matching contributions on our employees’ elective deferral contributions up to six percent of compensation up to the maximum statutory limits. The 401(k) Plan also provides for discretionary employer contributions. The expense recognized with respect to the 401(k) Plan was $0.1 million, $0.5 million, $0.9 million and $1.7 million for the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the Predecessor years ended December 31, 2015, and 2014, respectively, and is included as a component of “General and administrative expenses” in our Statements of Operations. Amounts representing accrued obligations to the 401(k) Plan of $0.1 million and $0.2 million are included in the “Accounts payable and accrued expenses” caption on our Consolidated Balance Sheets as of December 31, 2016 and 2015, respectively.

Defined Benefit Pension and Postretirement Health Care Plans

We maintain unqualified legacy defined benefit pension and defined benefit postretirement health care plans which cover a limited population of former employees that retired prior to 2000. The combined expense recognized with respect to these plans was less than $0.1 million, less than $0.1 million, $0.1 million and $0.1 million for the Successor period from September 13, 2016 through December 31, 2016, the Predecessor period from January 1, 2016 through September 12, 2016, and the Predecessor years ended December 31, 2015 and 2014, respectively, and is included as a component of “General and administrative expenses” in our Statements of Operations. The combined unfunded benefit obligations under these plans were $1.7 million and $2.1 million and are included within the “Accounts payable and accrued expenses” (current portion) and “Other liabilities” (noncurrent) captions on our Consolidated Balance Sheets as of December 31, 2016 and 2015, respectively.

19. Impairments

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

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12,2016	Year Ended December 31,	
			2015	2014
Oil and gas properties	$ —	$ —	$ 1,396,340	$ 791,809
Other – tubular inventory and well materials	—	—	1,084	—
	$ —	$ —	$ 1,397,424	$ 791,809

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, 2015				
Long-lived assets held for use	$ 311,886	$ —	$ —	$ 311,886
Year Ended December 31, 2014				
Long-lived assets held for use	$ 65,203	$ —	$ —	$ 65,203

We recorded no impairment charges during 2016. The significant deterioration of commodity prices in 2015, as reflected in the future strip pricing as of December 31, 2015, triggered an impairment of approximately $1.4 billion to our proved and unproved Eagle Ford properties, which required us to reduce their carrying value to a fair value of approximately $312 million. In 2015, we also recorded an impairment charge of $1.1 million attributable to surplus tubular inventory and well materials. In 2014, we recognized oil and gas asset impairments of: (i) $667.8 million in the East Texas, Granite Wash and Marcellus regions due to the decline in commodity prices in the fourth quarter of 2014, (ii) $6.1 million in connection with an uneconomic field drilled in the Mid-Continent region and (iii) $117.9 million to write-down our Selma Chalk assets in Mississippi triggered by the disposition of those properties.

20. Interest Expense

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

	Successor	Predecessor		
	Period From January 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Interest on borrowings and related fees [1]	$ 678	$ 36,012	$ 92,490	$ 91,866
Amortization of debt issuance costs [2]	226	22,189	4,749	4,197
Capitalized interest	(25)	(183)	(6,288)	(7,232)
	$ 879	$ 58,018	$ 90,951	$ 88,831

[1] Absent the bankruptcy proceedings and the corresponding suspension of the accrual of interest on unsecured debt, we would have recorded total contractual interest expense of $66.1 million for the period from January 1, 2016 through September 12, 2016, including $ 15.3 million attributable to the 2019 Senior Notes and $ 46.3 million attributable to the 2020 Senior Notes.

[2] Includes $20.5 million related to the accelerated write-off of unamortized debt issuance costs associated with the RBL and Senior Notes (see Note 11).

21. Earnings per Share

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

	Successor	Predecessor		
	Period From September 13, 2016 Through December 31, 2016	Period From January 1, 2016 Through September 12, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Net income (loss)	$ (5,296)	$ 1,054,602	$ (1,582,961)	$ (409,592)
Less: Preferred stock dividends [1]	—	(5,972)	(22,789)	(17,148)
Less: Induced conversion of preferred stock	—	—	—	(4,256)
Net income (loss) attributable to common shareholders – basic and diluted	$ (5,296)	$ 1,048,630	$ (1,605,750)	$ (430,996)
Weighted-average shares – basic	14,992	88,013	73,639	68,887
Effect of dilutive securities [2]	—	36,074	—	—
Weighted-average shares – diluted	14,992	124,087	73,639	68,887

[1] Preferred stock dividends were excluded from diluted earnings per share for the years ended December 31, 2015 and 2014, respectively, as the assumed conversion of the outstanding preferred stock would have been anti-dilutive.

[2] For the period from September 13, 2016 through December 31, 2016, less than 0.1 million potentially dilutive securities, represented by restricted stock units, had the effect of being anti-dilutive and were excluded from the calculation of diluted earnings per common share. For 2015 and 2014, respectively, approximately 30.2 million and 26.6 million potentially dilutive securities, including the Series A and Series B Preferred Stock, stock options 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)

	Predecessor			Successor	
	First Quarter	Second Quarter	Period From July 1, 2016 Through September 12, 2016	Period From September 13, 2016 Through September 30, 2016	Fourth Quarter
2016					
Revenues [1]	$ 30,497	$ 37,152	$ 26,661	$ 6,349	$ 32,654
Operating income (loss) [2]	$ (12,507)	$ (614)	$ (7,735)	$ 1,137	$ 10,254
Income (loss) attributable to common shareholders [3]	$ (36,625)	$ (64,800)	$ 1,150,055	$ (3,441)	$ (1,855)
Income (loss) per share – basic [4]	$ (0.43)	$ (0.73)	$ 12.88	$ (0.23)	$ (0.12)
Income (loss) per share – diluted [4]	$ (0.43)	$ (0.73)	$ 10.32	$ (0.23)	$ (0.12)
Weighted-average shares outstanding:					
Basic	85,941	89,051	89,292	14,992	14,992
Diluted	85,941	89,051	111,458	14,992	14,992

	Predecessor			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2015				
Revenues [5]	$ 74,527	$ 83,616	$ 111,984	$ 35,171
Operating income (loss) [6]	$ (57,876)	$ (40,982)	$ 3,604	$ (1,469,787)
Income (loss) attributable to common shareholders	$ (63,232)	$ (86,196)	$ 19,965	$ (1,476,287)
Income (loss) per share – basic [4]	$ (0.88)	$ (1.19)	$ 0.27	$ (19.32)
Income (loss) per share – diluted [4]	$ (0.88)	$ (1.19)	$ 0.25	$ (19.32)
Weighted-average shares outstanding:				
Basic	71,820	72,398	72,651	76,430
Diluted	71,820	72,398	103,452	76,430

[1] Includes gains (losses) on sales of assets of $(0.2) million, $0.9 million, $0.5 million and less than $(0.1) million during the quarters ended March 31, 2016 and June 30, 2016, the period from July 1, 2016 through September 12, 2016 and the quarter ended December 31, 2016, respectively.

[2] The equity-classified share-based compensation expense included in the operating loss for the Predecessor periods from July 1, 2016 through September 12, 2016, includes an adjustment of $5.3 million to correct for an error that occurred in the reporting of equity-classified share-based compensation expense for the three months ended June 30, 2016. We have assessed the quantitative and qualitative factors with respect to this error as well as the effect of the correcting adjustment being recorded in the Predecessor period from July 1, 2016 through September 12, 2016 and determined that the amount and timing of the adjustment is not material to the Consolidated Financial Statements taken as a whole for any of the subject periods.

[3] Includes reorganization items attributable to our bankruptcy proceedings of $7.4 million (expense) during the quarter ended June 30, 2016 and $1.152 billion (income) during the period from July 1, 2016 through September 12, 2016 (see Notes 4 and 5).

[4] 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.

[5] Includes gains (losses) on sales of assets of $50.8 million and $(9.5) million during the quarters ended September 30, 2015 and December 31, 2015, respectively.

[6] Includes impairments of oil and gas properties of $1.4 billion for the quarter ended December 31, 2015.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

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 as of December 31, 2016 and 2015 were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. Estimates of our proved oil and gas reserves as of December 31, 2014 were prepared by Wright & Company, Inc. DeGolyer and MacNaughton, Inc. and Wright & Company, Inc. are both independent firms of petroleum engineers, geologists, geophysicists and petrophysicists. Our Vice President, Operations & Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. and 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, 2013 (Predecessor)	60,697	21,966	322,093	136,345
Revisions of previous estimates	(8,286)	(7,727)	(98,386)	(32,411)
Extensions and discoveries	21,427	6,090	31,842	32,824
Production	(4,644)	(1,110)	(13,084)	(7,934)
Purchase of reserves	—	—	—	—
Sale of reserves in place	(188)	—	(83,200)	(14,055)
December 31, 2014 (Predecessor)	69,006	19,219	159,265	114,769
Revisions of previous estimates	(34,525)	(8,667)	(46,859)	(51,002)
Extensions and discoveries	2,519	321	1,584	3,105
Production	(4,923)	(1,381)	(9,713)	(7,923)
Purchase of reserves	—	—	—	—
Sale of reserves in place	(2,615)	(2,288)	(62,124)	(15,258)
December 31, 2015 (Predecessor)	29,462	7,204	42,153	43,691
Revisions of previous estimates	(1,359)	(1,225)	(8,661)	(4,028)
Extensions and discoveries	11,529	1,483	7,196	14,213
Production	(3,021)	(697)	(4,006)	(4,386)
Purchase of reserves	—	—	—	—
Sale of reserves in place	—	—	—	—
December 31, 2016 (Successor)	36,611	6,765	36,682	49,490
Proved Developed Reserves:				
December 31, 2014 (Predecessor)	22,054	8,065	94,565	45,880
December 31, 2015 (Predecessor)	20,188	6,201	37,172	32,585
December 31, 2016 (Successor)	17,734	4,335	24,899	26,219
Proved Undeveloped Reserves:				
December 31, 2014 (Predecessor)	46,952	11,154	64,700	68,889
December 31, 2015 (Predecessor)	9,274	1,003	4,981	11,106
December 31, 2016 (Successor)	18,877	2,430	11,783	23,271

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

Year Ended December 31, 2016

We had downward revisions of 4.0 MMBOE primarily as a result of the following: (i) downward revisions of 1.7 MMBOE due to lower EURs for natural gas and NGLs net of higher expected crude oil recoveries attributable to our existing and new Eagle Ford wells, (ii) downward revisions of 1.3 MMBOE to our proved undeveloped reserves, all of which are located in the Eagle Ford, due to the loss of certain locations resulting from changes in the timing of our development plans and lower EURs, (iii) downward revisions of 0.7 MMBOE (Granite Wash - 0.4 MMBOE and Eagle Ford 0.3 MMBOE) due to lower commodity prices compared to year-end 2015 and (iv) downward revisions of 0.3 MMBOE to our Granite Wash wells due to well performance. Extensions and discoveries of 14.2 MMBOE for our proved undeveloped reserves were attributable primarily to the resumption of our development plans in the Eagle Ford.

Year Ended December 31, 2015

We had downward revisions of 51.0 MMBOE primarily as a result of the following: (i) downward revisions of 45.2 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Eagle Ford, (ii) downward revisions of 2.9 MMBOE attributable to certain proved wells in the Eagle Ford and (iii) downward revisions of 2.5 MMBOE due to well performance issues, primarily in the Granite Wash in Oklahoma. We added 3.1 MMBOE due primarily to the drilling of 61 gross (38.6 net) wells and the addition of proved undeveloped locations in the Eagle Ford. We sold our Cotton Valley and Haynesville Shale assets in East Texas as well as certain non-core Eagle Ford wells resulting in a decrease of 15.3 MMBOE.

Year Ended December 31, 2014

We had downward revisions of 32.4 MMBOE primarily as a result of the following: (i) downward revisions of 20.7 MMBOE due to the removal of proved undeveloped locations that would not be developed within five years primarily in the Cotton Valley and Haynesville Shale (19.1 MMBOE) and the Granite Wash (1.6 MMBOE), (ii) downward revisions of 8.3 MMBOE (4.5 MMBOE of proved developed and 3.8 MMBOE of proved undeveloped) attributable to certain proved wells in the Eagle Ford and (iii) downward revisions of 3.4 MMBOE due to well performance issues (2.3 MMBOE in the Cotton Valley and Haynesville Shale and 1.1 MMBOE in the Granite Wash). We added 32.8 MMBOE due primarily to the drilling of 84 gross (51.6 net) wells and the addition of proved undeveloped locations in the Eagle Ford. We sold our Selma Chalk assets in Mississippi as well as certain wells in Oklahoma resulting in a decrease of 14.1 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:

	Successor	Predecessor		
	December 31,	September 12,	December 31,	
	2016	2016	2015	2014
Oil and gas properties:				
Proved	$ 251,083	$ 241,597	$ 2,678,415	$ 3,390,482
Unproved	4,719	8,338	6,881	125,676
Total oil and gas properties	255,802	249,935	2,685,296	3,516,158
Other property and equipment	1,230	1,229	11,330	55,601
Total capitalized costs relating to oil and gas producing activities	257,032	251,164	2,696,626	3,571,759
Accumulated depreciation and depletion	(11,669)	—	(2,354,405)	(1,749,752)
Net capitalized costs relating to oil and gas producing activities [1]	$ 245,363	$ 251,164	$ 342,221	$ 1,822,007

[1] Excludes property and equipment attributable to our corporate operations which is comprised of 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:

	Successor	Predecessor		
	September 13 to December 31,	January 1 to September 12,	Year Ended December 31,	
	2016	2016	2015	2014
Development costs [1]	$ 4,887	$ 4,129	$ 294,445	$ 690,277
Unproved property acquisition costs	—	—	16,052	98,443
Exploration costs [2]	567	8,311	939	5,966
Total costs incurred	$ 5,454	$ 12,440	$ 311,436	$ 794,686

[1] Does not include non-cash ARO assets of $0.1 million, $.0.6 million, $0.3 million and $0.4 million that were added to capitalized costs relating to oil and gas producing activities during the Successor period ended December 31, 2016, the Predecessor period ended September 12, 2016 and the years ended December 31, 2015 and 2014, respectively.

[2] Includes geological and geophysical costs and delay rentals of $0.6 million for the Successor period ended December 31, 2016, less than $0.1 million for the Predecessor period ended September 12, 2016 and $0.9 million and $6.0 million during the years ended December 31, 2015 and 2014, respectively. Also includes drilling rig termination charges of $1.7 million, $5.9 million and $0.8 million during the Predecessor period ended September 12, 2016 and the years ended December 31, 2015 and 2014, respectively, a $2.0 million charge for failure to complete a drilling carry commitment, a $0.6 million charge for unutilized coiled tubing services and a $4.0 million write-off of certain uncompleted well costs during the Predecessor period ended ended September 12, 2016, all of which were charged to exploration expense.

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, 2014 [1]	$ 94.99	$ 25.49	$ 4.35
As of December 31, 2015 [1]	$ 50.28	$ 14.44	$ 2.70
As of December 31, 2016 [1]	$ 42.75	$ 12.33	$ 2.48

[1] Crude oil and natural gas prices were based on average (beginning of month basis) sales prices per Bbl and MMBtu. The representative prices of crude oil and natural gas as adjusted for basis differentials and product quality were as follows: Crude oil - $40.97, $45.78 and $92.91 each per barrel. NGLs - $11.82, $13.15 and $25.09 each per barrel and Natural gas - $2.40, $2.59 and $4.32 each per MMBtu, as of December 31, 2016, 2015 and 2014, respectively. NGL prices were estimated as a percentage of the base crude oil price.

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

	December 31,		
	2016	2015	2014
Future cash inflows	$ 1,667,971	$ 1,557,246	$ 7,589,354
Future production costs	(673,538)	(731,951)	(2,239,491)
Future development costs	(327,213)	(206,616)	(2,175,530)
Future net cash flows before income tax	667,220	618,679	3,174,333
Future income tax expense	—	—	(686,562)
Future net cash flows	667,220	618,679	2,487,771
10% annual discount for estimated timing of cash flows	(349,670)	(295,368)	(1,305,326)
Standardized measure of discounted future net cash flows	$ 317,550	$ 323,311	$ 1,182,445

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,		
	2016	2015	2014
Sales of oil and gas, net of production costs	$ (89,080)	$ (180,455)	$ (418,300)
Net changes in prices and production costs	(11,971)	(1,442,919)	(222,349)
Changes in future development costs	59,266	1,376,226	624,068
Extensions and discoveries	35,321	19,396	261,410
Development costs incurred during the period	6,775	222,612	380,650
Revisions of previous quantity estimates	(38,151)	(436,898)	(614,497)
Purchases of reserves-in-place	—	—	—
Sale of reserves-in-place	—	(86,662)	(44,805)
Changes in production rates	(252)	(767,689)	(382,015)
Accretion of discount	32,331	147,245	171,663
Net change in income taxes	—	290,010	162,842
Net decrease	(5,761)	(859,134)	(81,333)
Beginning of year	323,311	1,182,445	1,263,778
End of year	$ 317,550	$ 323,311	$ 1,182,445

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

As disclosed in our Current Report on Form 8-K, filed on September 15, 2016, we engaged Grant Thornton LLP ("Grant Thornton") as the Company's new independent registered public accounting firm to audit the Company's financial statements for the fiscal year ending December 31, 2016, and dismissed KPMG LLP ("KPMG") as the Company's independent registered accounting firm. The decision to change the Company's independent registered accounting firm from KPMG to Grant Thornton was approved by the Audit Committee of the Board of Directors of the Company.

During the fiscal years ended December 31, 2015 and December 31, 2014, and through September 13, 2016, there were no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedures, that if not resolved to the satisfaction of KPMG, would have caused KPMG to make reference thereto in its reports on the Company's financial statements for such years.

During the fiscal years ended December 31, 2015 and 2014, and the subsequent interim period through the period September 13, 2016, there were no "reportable events" (as that term is defined in Item 304(a)(1)(v) of Regulation S-K).

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Principal 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, 2016. 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 Principal Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2016, such disclosure controls and procedures were effective.

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

Our management, including our Principal 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, 2016. This evaluation was completed based on the framework established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our management has concluded that, as of December 31, 2016, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

Management's Annual Report on Internal Control Over Financial Reporting was not subject to attestation by our independent registered public accounting firm pursuant to the rules of the SEC that permit us to provide only management's report within this report. Therefore, this report does not include such an attestation.

(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

None.

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 49 of this Annual Report on Form 10-K.
(2.1)	Second Amended Joint Plan of Reorganization of Penn Virginia Corporation and Its Debtor Affiliates (Technical Modifications) filed pursuant to Chapter 11 of the United States Bankruptcy Code filed on August 10, 2016 with the United States Bankruptcy Court for the Eastern Division of Virginia, Richmond Division (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on August 17, 2016).
(2.2)	Disclosure Statement for the First Amended Joint Plan of Reorganization of Penn Virginia Corporation and Its Debtor Affiliates and Amended Exhibits Thereto filed pursuant to Chapter 11 of the United States Bankruptcy Code filed on June 28, 2016 with the United States Bankruptcy Court for the Eastern Division of Virginia, Richmond Division (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed on August 17, 2016).
(3.1)	Second Amended and 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 September 14, 2016).
(3.2)	Second Amended and Restated Bylaws of Penn Virginia Corporation (incorporated by reference to Exhibit 3.2 to Registrant 's Current Report on Form 8-K filed on September 14, 2016).
(10.1)	Credit Agreement, dated as of September 12, 2016, by and among Penn Virginia Holding Corp., Penn Virginia Corporation, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 12, 2016).
(10.2)	Pledge and Security Agreement, dated as of September 12, 2016, by Penn Virginia Holding Corp., Penn Virginia Corporation and the other grantors party thereto in favor of Wells Fargo Bank, National Association, as administrative agent for the benefit of the secured parties thereunder (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on September 12 2016).
(10.3)	Registration Rights Agreement, dated as of September 12, 2016, between Penn Virginia Corporation and the holders party thereto (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on September 12 2016).
(10.4)	Second Amended and Restated Construction and Field Gathering Agreement by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. dated August 1, 2016 (incorporated by reference to Exhibit 10.5 to Registrant's Quarterly Report on Form 10-Q filed on November 14, 2016).
(10.5)	First Amended and Restated Crude Oil Marketing Agreement dated as of August 1, 2016, by and between Penn Virginia Oil & Gas, L.P., Republic Midstream Marketing, LLC and solely for purposes of Article V therein, Penn Virginia Corporation(incorporated by reference to Exhibit 10.6 to Registrant's Quarterly Report on Form 10-Q filed on November 14, 2016).
(10.7)*	Brooks Employment Agreement dated May 9, 2016 (incorporated by reference to Exhibit 10.5 to Registrant 's Current Report on Form 8-K filed on May 13, 2016).
(10.7.1)*	Amendment No.1 to Employment Agreement, dated September 28, 2016 between the Company and John A. Brooks (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on October 4, 2016).
(10.8)*	Hartman Employment Agreement dated May 9, 2016 (incorporated by reference to Exhibit 10.4 to Registrant 's Current Report on Form 8-K filed on May 13, 2016).
(10.9)*	Penn Virginia Corporation 2016 Management Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on October 11, 2016).
(10.9.1)*	Form of Nonqualified Stock Option Award Agreement (incorporated by reference to Exhibit 10.2 to Registrant 's Current Report on Form 8-K filed on October 11, 2016).
(10.9.2)*	Form of Officer Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on January 30, 2017).
(10.9.3)*	Form of Performance Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to Registrant 's Current Report on Form 8-K filed on January 30, 2017).
(10.9.4)*	Form of Director Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.1 to Registrant 's Current Report on Form 8-K filed on December 21, 2016).
(10.10)	Consulting Agreement between Penn Virginia Corporation and Nancy M. Snyder (incorporated by reference to Exhibit 10.5 to Registrant 's Current Report on Form 8-K filed on October 11, 2016).
(10.11)	Form of Director Indemnification Agreement (incorporated by reference to Exhibit 10.6 to Registrant 's Current Report on Form 8-K filed on October 11, 2016).

(21.1)	Subsidiaries of Penn Virginia Corporation. **
(23.1)	Consent of Grant Thornton LLP. **
(23.2)	Consent of KPMG LLP. **
(23.3)	Consent of DeGolyer and MacNaughton. **
(23.4)	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 DeGolyer and MacNaughton dated February 9, 2017 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.
** Filed herewith.

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
(Principal Financial Officer)

March 16, 2017

By: /s/ TAMMY L. HINKLE
Tammy L. Hinkle
Vice President 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/ JOHN A. BROOKS **John A. Brooks**	Interim Principal Executive Officer and Chief Operating Officer (Principal Executive Officer)	March 16, 2017
/s/ STEVEN A. HARTMAN **Steven A. Hartman**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 16, 2017
/s/ TAMMY L. HINKLE **Tammy L. Hinkle**	Vice President and Controller (Principal Accounting Officer)	March 16, 2017
/s/ DARIN G. HOLDERNESS **Darin G. Holderness**	Director	March 16, 2017
/s/ MARC MCCARTHY **Marc McCarthy**	Director	March 16, 2017
/s/ HARRY QUARLS **Harry Quarls**	Chairman of the Board	March 16, 2017
/s/ JERRY R. SCHUYLER **Jerry R. Schuyler**	Director	March 16, 2017

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 and Shareholders
Penn Virginia Corporation:

We have issued our report dated March 16, 2017, with respect to the consolidated financial statements included in the Annual Report of Penn Virginia Corporation on Form 10-K for the year ended December 31, 2016. We consent to the incorporation by reference of said report in the Registration Statements of Penn Virginia Corporation on Form S-1 (File No. 333-214709) and on Form S-8 (File No. 333-213979).

/s/ GRANT THORNTON LLP

Houston, Texas
March 16, 2017

Exhibit 23.2

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 (No. 333-213979) on Form S-8 and (No. 333-214709) on Form S-1 of Penn Virginia Corporation and subsidiaries of our report dated March 15, 2016, with respect to the consolidated balance sheet of Penn Virginia Corporation and subsidiaries as of December 31, 2015, and the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2015, which report appears in the December 31, 2016 annual report on Form 10-K of Penn Virginia Corporation.

Our report dated March 15, 2016 contains an explanatory paragraph that states that the Company has suffered recurring losses from operations and is dependent on obtaining additional financing to continue its planned principal business operations. These factors raise substantial doubt about its ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of that uncertainty.

/s/ KPMG LLP

Houston, Texas
March 16, 2017

Exhibit 23.3

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 16, 2017

Penn Virginia Corporation
14701 Saint Mary's Lane
Suite 275
Houston, Texas 77079

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our "Report as of December 31, 2016 on Reserves and Revenue of Certain Properties owned by Penn Virginia Corporation" (our Report) in Part I and in the "Notes to Consolidated Financial Statements" portions of the Annual Report on Form 10-K of Penn Virginia Corporation for the year ended December 31, 2016 (the Annual Report). In addition, we hereby consent to the incorporation by reference of our letter report dated February 9, 2017 in the "Exhibits and Financial Statement Schedules" portion of the Annual Report. We further consent to the incorporation by reference of references to DeGolyer and MacNaughton and to our Report in Penn Virginia Corporation's Registration Statements on Form S-1/A (File No. 333-214709) and Form S-8 (File No. 333-213979).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 23.4

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 No. 333-213979) and Form S-1 (No. 333-214709) 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, 2015, Job 14.1649*, and dated January 9, 2015, 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 March 16, 2017.

Wright & Company, Inc.
TX Firm Reg. No. F-12302

/s/ D. Randall Wright

By: D. Randall Wright
President

Brentwood, Tennessee
March 16, 2017

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, John A. Brooks, Interim Principal 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: March 16, 2017

/s/ JOHN A. BROOKS

John A. Brooks
Interim Principal 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: March 16, 2017

/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, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John A. Brooks, Interim Principle 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: March 16, 2017

/s/ JOHN A. BROOKS

John A. Brooks
Interim Principle 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, 2016, 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: March 16, 2017

/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

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 9, 2017

Penn Virginia Corporation
14701 Saint Mary's Lane
Suite 275
Houston, Texas 77079

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2016, of certain selected properties in which Penn Virginia Corporation (Penn Virginia) has represented that it owns an interest. This evaluation was completed on February 9, 2017. Penn Virginia has represented that these properties account for 100 percent of Penn Virginia’s net proved reserves as of December 31, 2016. The properties evaluated herein are located in Oklahoma and Texas. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the Securities and Exchange Commission (SEC) of the United States. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K and is to be used for inclusion in certain SEC filings by Penn Virginia.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2016. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Penn Virginia after deducting all interests owned by others.

Estimates of oil, condensate, NGL, and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Penn Virginia personnel, from Penn Virginia files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Penn Virginia with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Penn Virginia, and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production.

In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data were available.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves are expressed at a temperature base of 60 degrees Fahrenheit and at a pressure base of 14.65 pounds per square inch absolute. Gas quantities included herein are expressed in thousands of cubic feet (Mcf). Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements. Oil, condensate, and NGL reserves included in this report are expressed in barrels (bbl) representing 42 United States gallons per barrel. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves - Proved oil and gas reserves are 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 prior to 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves - Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves - Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be 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.

(ii) Undrilled locations can be 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4-10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

The development status shown herein represents the status applicable on December 31, 2016. In the preparation of this study, data available from wells drilled on the evaluated properties through December 31, 2016, were used in estimating gross ultimate recovery. When applicable, gross production estimated through December 31, 2016, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2016. In some fields this required that the production rates be estimated for up to 2 months, since production data from certain properties were available only through October 2016.

Primary Economic Assumptions

Revenue values in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth of future net revenue. Future gross revenue is that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from the future gross revenue. Present worth of future net revenue is calculated by discounting the future net revenue at the arbitrary rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Revenue values in this report were estimated for proved reserves using price and expenditure assumptions provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following assumptions were used for estimating future prices and expenditures:

Oil, Condensate, and NGL Prices

Penn Virginia has represented that the oil, condensate, and NGL prices were based on West Texas Intermediate (WTI) pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The oil, condensate, and NGL prices were calculated using differentials furnished by Penn Virginia to the reference price of $42.75 per barrel. The resulting volume-weighted average prices over the lives of the properties were $40.97 per barrel of oil and condensate and $11.82 per barrel of NGL.

Gas Prices

Penn Virginia has represented that the gas prices were based on Henry Hub pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials furnished by Penn Virginia to the reference price of $2.48 per million British thermal units ($/MMBtu) and held constant thereafter. British thermal unit factors provided by Penn Virginia were used to convert prices from $/MMBtu to dollars per thousand cubic feet ($/Mcf). The resulting volume-weighted average price over the lives of the properties was $2.402 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Penn Virginia based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Penn Virginia and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2016 values, provided by Penn Virginia, and were not adjusted for inflation. Abandonment costs were provided by Penn Virginia for all properties.

Our estimates of Penn Virginia's net proved reserves attributable to the reviewed properties were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2016			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved				
Developed Producing	17,497	4,305	24,751	25,927
Developed Non-Producing	237	30	148	292
Undeveloped	18,877	2,430	11,783	23,271
Total Proved	**36,611**	**6,765**	**36,682**	**49,490**

Note: Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue and costs attributable to the production and sale of Penn Virginia's net proved reserves of the properties evaluated, as of December 31, 2016, are summarized in thousands of dollars (M$) as follows:

	Proved			
	Developed Producing (M$)	**Developed Non-Producing (M$)**	**Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	827,571	10,421	829,979	1,667,971
Production and Ad Valorem Taxes	63,844	797	63,487	128,128
Operating Expenses	350,177	2,566	192,667	545,410
Capital and Abandonment Costs	16,247	1,507	309,459	327,213
Future Net Revenue	397,303	5,551	264,366	667,220
Present Worth at 10 Percent	246,220	3,332	67,998	317,550

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2016, estimated oil, condensate, NGL, and gas reserves.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries - Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4-10(a) (1)-(32) of Regulation S-X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S-K of the Securities and Exchange Commission; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Penn Virginia. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Penn Virginia. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON

Texas Registered
Engineering Firm F-716

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

Exhibit 99.1

CERTIFICATE of QUALIFICATION

I, Gregory K. Graves, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Penn Virginia dated
2. February 9, 2017, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

3. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 32 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton