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, 2019

or

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

For the transition period from ____ to ____

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)

16285 Park Ten Place, Suite 500
Houston, TX 77084
(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	Trading Symbol(s)	Name of exchange on which registered
Common Stock, $0.01 Par Value	**PVAC**	**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 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 Securities Exchange Act of 1934 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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was $412,236,913 as of June 28, 2019 (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 NASDAQ Global Select Market.

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 February 21, 2020, 15,157,919 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 4, 2020, 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 EndedDecember 31, 2019

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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. We use words such as “anticipate,” “guidance,” “assumptions,” “projects,” “estimates,” “expects,” “continues,” “intends,” “plans,” “believes,” “forecasts,” “future,” “potential,” “may,” “possible,” “could” and variations of such words or similar expressions to identify forward-looking statements. 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:

- risks related to completed acquisitions, including our ability to realize their expected benefits;
- our ability to satisfy our short-term and long-term liquidity needs, including our ability 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;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in volatile and depressed commodity price environments;
- the decline in, sustained market uncertainty of, 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 gas reserves and sustain production;
- our ability to generate profits or achieve targeted reserves in our development and exploratory drilling and well operations;
- our ability to meet guidance, market expectations and internal projections, including type curves
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, materials, supplies and services at reasonable costs;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity or other transportation 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 gas reserves;
- use of new techniques in our development, including choke management and longer laterals;
- drilling, completion and operating risks, including adverse impacts associated with well spacing and a high concentration of activity;
- 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;
- 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 with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for substantially all of our revenues and production;
- 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;
- the impact and uncertainty of world health events;
- the impact and costs associated with litigation or other legal matters;
- sustainability initiatives; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, or SEC, including the risks set forth in Part I, Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2019.

Additional information concerning these and other factors can be found in our press releases and public filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management’s views only as of the date hereof. 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.

EBITDAX. A measure of profitability utilized in the oil and gas industry representing earnings before interest, income taxes, depreciation, depletion, amortization and exploration expenses. EBITDAX is not a defined term or measure in generally accepted accounting principles, or GAAP (see below).

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.

LIBOR. London Interbank Offered Rate.

LLS. Light Louisiana Sweet, a crude oil pricing index reference.

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.

MEH. Magellan East Houston, a crude oil pricing index reference.

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.

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.

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. Under appropriate circumstances, undeveloped acreage may not be subject to expiration if properly held by production, as that term is defined above.

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 of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale, or the Eagle Ford, in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

We were incorporated in the Commonwealth of Virginia in 1882. Our common stock is publicly traded on the Nasdaq under the symbol "PVAC." Our headquarters and corporate office is located in Houston, Texas. We also have a field 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.

Current Operations

We lease a highly contiguous position of approximately 87,400 net acres (as of December 31, 2019) in the core liquids-rich area or "volatile oil window" of the Eagle Ford in Gonzales, Lavaca, Fayette and Dewitt Counties in Texas, which we believe contains a substantial number of drilling locations that will support a multi-year drilling inventory.

In 2019, our total production was comprised of 74 percent crude oil, 15 percent NGLs and 11 percent natural gas. Crude oil accounted for 93 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, 2019, our total proved reserves were approximately133 MMBOE, of which 42 percent were proved developed reserves and 74 percent were crude oil. As of December 31, 2019, we had 510 gross (430.1 net) productive wells, approximately 98 percent of which we operate, and leased approximately 100,200 gross (87,400 net) acres of leasehold and royalty interests, approximately 9 percent of which were undeveloped. Approximately 91 percent of our total acreage is HBP and includes a substantial number of undrilled locations. During 2019, we drilled and completed 48 gross (43.3 net) wells, all in the Eagle Ford. For a more detailed discussion of our production, reserves, drilling activities, wells and acreage, see Part I, Item 2, "Properties."

In 2018 and 2017 we completed the acquisition of certain oil and gas assets from Hunt Oil Company, or Hunt, and Devon Energy Corporation, or Devon, including oil and gas leases covering approximately 9,700 and 19,600 net acres located primarily in Gonzales and Lavaca Counties, Texas, respectively, or the Hunt and Devon Acquisitions. These acquisitions substantially expanded our Eagle Ford operations to their present scale. For a more detailed discussion of these transactions, see Note 4 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 that provide us with field gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production through February 2041 and February 2026, respectively, as well as volume capacity support for certain downstream interstate pipeline transportation.

Natural gas service contracts. We have an agreement that provides us with field gathering, compression and short-haul transportation services for a substantial portion of our natural gas production and gas lift for all of our hydrocarbon production until 2039.

Natural gas processing contracts. We have two agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. The more significant of these agreements extends through June 2029 while the other agreement, which represents a minor portion of our total processing requirements, is evergreen in term with either party having the right to terminate with 30-days' notice to the counterparty.

Drilling and Completion. From time to time we enter into drilling, completion and materials contracts in the ordinary course of business to ensure availability of rigs, frac crews and materials to satisfy our development program. As of December 31, 2019, there were no drilling, completion or materials agreements with terms that extended beyond one year.

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, 2019, approximately 76 percent of our consolidated product revenues were attributable to four customers: BP Products North America Inc.; Phillips 66 Company; Shell Trading (US) Company and Trafigura Trading LLC.

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 crude 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, frac fleets, sand and other equipment and materials necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such materials, 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 and regulations that govern oil and gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

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. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. 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, 2019, we have recorded asset retirement obligations of $4.9 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. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation or enforcement of environmental laws and regulations and may thereby increase compliance costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

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. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. 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. States also have environmental cleanup laws analogous to CERCLA, including Texas.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup 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. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production-related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree required the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary; the EPA ultimately determined that a revision was not necessary. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

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 imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters, such as waters of the United States. The discharge of pollutants, including dredge or fill materials in regulated wetlands, into regulated waters or wetlands without a permit issued by the EPA, the U.S. 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. In January 2017, the United States Supreme Court accepted review of the rule to determine whether jurisdiction to hear challenges to the rule rests with the federal district or appellate courts. In January

2018, the Supreme Court ruled that district courts have jurisdiction over challenges to the rule. In June 2017, the EPA and the Corps proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of WOTUS. Under the proposal, the first step would be to rescind the 2015 final rule and put back into effect the narrower language defining WOTUS under the Clean Water Act that existed prior to the rule. The second step would be a notice-and-comment rule-making in which the agencies will conduct a substantive reevaluation of the definition of WOTUS. In September 2019, the EPA finalized the first step in this process. In January 2020, the EPA finalized the second step in this process, finalizing a rule that narrowed the regulatory definition of WOTUS. Litigation challenging the repeal of the August 2015 rule is pending.

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. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

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. The Underground Injection Well Program requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells, and regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water or other oil and gas waste to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be, or determined to be, contributing to seismic activity, then TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that disposal well. TRC has used this authority to deny permits for waste disposal wells. The potential adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

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 formation, and is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. In addition, separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to induced seismicity. The EPA also 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, including a removal of the exemption for hydraulic fracturing from the SDWA, 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 commercially feasible without the use of hydraulic fracturing.

Chemical Disclosures Related to Hydraulic Fracturing. Texas has 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 has 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

On April 17, 2012, the EPA issued final rules to subject oil and 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 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. In June 2017, the EPA proposed a two year stay of the fugitive emissions monitoring requirements, pneumatic pump standards and closed vent system certification requirements in the 2016 NSPS rule for the oil and gas industry while it reconsiders these aspects of the rule. The proposal is still under consideration. More recently, in September 2018, the EPA proposed targeted improvements to the rule, including amendments to the rule's fugitive emissions monitoring requirements, and is in the process of finalizing the amendments, which it originally expected to do in late 2019. Separately, on August 28, 2019, the EPA proposed amendments to the 2012 and 2016 NSPS for the Oil and Natural Gas Industry that would remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS, both for ozone-forming VOCs, and for "greenhouse gases," or GHGs. The existing NSPS regulates GHGs through limitations on emissions of methane. The amendments also would rescind the methane requirements in the 2016 NSPS that apply to sources in the production and processing segments of the industry. As an alternative, the EPA also is proposing to rescind the methane requirements that apply to all sources in the oil and natural gas industry, without removing any sources from the current source category. The U.S. Bureau of Land Management, or BLM, finalized its own rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted final rules in January 2017; operators generally had one year from the January 2017 effective date of the rule to come into compliance with the rule's requirements. However, in September 2018, the BLM announced a revised rule which would scale back the waste-prevention requirements of the 2016 rule. Environmental groups sued in federal district court a day later to challenge the legality of aspects of the revised rule, and the outcome of this litigation is currently uncertain. These rules have required changes to our operations, including the installation of new equipment to control emissions. The EPA had announced in 2016 an intent to impose methane emission standards for existing sources, but the agency was sued by multiple states for failing to implement these standards following the agency's withdrawal of information collection requests for oil and gas facilities. These rules would 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 gas industry remain a possibility and could result in increased compliance costs on our operations.

In November 2015, the EPA revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as non-attainment, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Generally, it will take the states several years to develop compliance plans for their non-attainment 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 June 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. In response to findings that emissions of carbon dioxide, methane and other GHGs, present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources.

Both in the United States and worldwide, there is increasing attention being paid to the issue of climate change and the contributing effect of 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. However, in November 2019, the Trump administration formally moved to exit the Paris Agreement, initiating the treaty-mandated one-year process at the end of which the United States can officially exit the agreement. The United States’ adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

In August 2015, the EPA issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under this rule, nationwide carbon dioxide emissions would be reduced by approximately 30 percent from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of this rule pending judicial review. In August 2019, the EPA finalized the repeal of the 2015 regulations and replaced them with the Affordable Clean Energy rule, or ACE, that designates heat rate improvement, or efficiency improvement, as the best system of emissions reduction for carbon dioxide from existing coal-fired electric utility generating units. Both the appropriateness of the repeal of the 2015 regulations and the adequacy of ACE are currently subject to litigation.

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. Many states have established GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. 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. 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.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment of the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of some of our oil and gas projects.

Employees and Labor Relations

We had a total of 94 employees as of December 31, 2019. We hire independent contractors on an as needed basis. 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, Audit Committee Charter, Compensation and Benefits Committee Charter, Nominating and Governance Committee Charter and Reserves 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 Reports 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. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we furnish or file with the SEC. 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.

Risk Factors Associated with our General Business

Prices for crude oil, NGLs and natural gas are dependent on many factors that are beyond our control and strongly affect our financial condition, results of operations and cash flows.

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 extent to which the members of the Organization of Petroleum Exporting Countries and other oil exporting nations agree upon and maintain production constraints and oil price controls;
- overall domestic and foreign economic conditions, including adverse conditions driven by political, health or weather events;
- prices and availability of, and demand for, alternative fuels;
- the effect of energy conservation efforts, alternative fuel requirements and climate change-related initiatives;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil, natural gas and NGLs so as to minimize emissions of carbon dioxide and methane GHGs;
- volatility and trading patterns in the commodity-futures markets;
- technological advances or social attitudes and policies affecting energy consumption and energy supply;
- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which crude oil prices are benchmarked globally, against foreign currencies;
- changes in trade relations and policies, including the imposition of tariffs by the United States or China;
- risks related to the concentration of our operations in the Eagle Ford Shale field in South Texas;
- speculation by investors in oil and gas;
- the availability, cost, proximity and capacity of gathering, processing, refining and transportation facilities;
- the cost and availability of products and personnel needed for us to produce oil and gas;
- weather conditions;
- the impact and uncertainty of world health events; and
- domestic and foreign governmental relations, regulation and taxation, including limits on the United States' ability to export crude oil.

The long-term effects of these and other conditions on the prices of oil and natural gas are uncertain, and there can be no assurance that the demand or pricing for our products will follow historic patterns or recover meaningfully in the near term. For example, oil and natural gas prices continued to be volatile in 2019, and the recent oil and gas industry downturn has (and current market conditions have) resulted in reduced demand for our products, which have had, and may in the future have, a material adverse impact on its financial condition, results of operations and cash flows. For example, the NYMEX oil prices in 2019 ranged from a high of $66.30 to a low of $46.54 per Bbl and the NYMEX natural gas prices in 2019 ranged from a high of $4.12 to a low of $1.82 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices ranged from highs to lows of $63.27 to $49.59 per Bbl and $2.17 to $1.85 per MMBtu, respectively, during the period from January 1, 2020 to February 14, 2020. 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, or sustained market uncertainty, 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, cash flows and borrowing capacity, stock price, 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.

Exploration and development drilling are high-risk activities with many uncertainties and may not result in commercially productive reserves.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Oil and gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and gas production. The costs of drilling, completing and operating wells are often substantial and uncertain, and drilling and completion 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;
- the use of multi-well pad drilling that requires the drilling of all of the wells on a pad until any one of the pad's wells can be brought into production;
- risks associated with drilling horizontal wells and extended lateral lengths, such as deviating from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- risks associated with downspacing and multi-well pad drilling;
- fracture stimulation accidents or failures;
- reductions in oil, natural gas and NGL prices;
- elevated pressure or irregularities in geologic formations;
- loss of title or other title related issues;
- equipment failures or accidents;
- costs, shortages or delays in the availability of drilling rigs, frac fleets, crews, equipment and materials;
- shortages in experienced labor;
- crude oil, NGLs or natural gas gathering, transportation, processing, storage and export facility availability restrictions or limitations;
- surface access restrictions;
- delays imposed by or resulting from compliance with regulatory requirements, including any hydraulic fracturing regulations and other applicable regulations, and the failure to secure or delays in securing necessary regulatory, contractual and third-party approvals and permits;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;
- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms;
- limitations in the market for crude oil, natural gas and NGLs;
- fires, explosions, blow-outs and surface cratering;
- adverse weather conditions; and
- actions by third-party operators of our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. 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 type curves we use in our development plans from time to time are only estimates of performance of the acreage we might develop and actual production can differ materially. Furthermore, the cost of drilling, completing, equipping and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. 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, and we cannot 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 gas from all of them.

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

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing.

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the risk of unintentional communication with other adjacent wells and the potential to reduce total recoverable reserves from the reservoir. If these risks materialize and negatively impact our results of operations relative to guidance or market expectations, the research analysts who cover us may downgrade our common stock or change their recommendations or earnings or performance estimates, which may result in a decline in the market price of our common stock.

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 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 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 wells within such project area.

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.

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

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.

Moreover, the oil and 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, including geologists, geophysicists, engineers and other professionals. 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. The prevailing prices of crude oil, NGLs and natural gas also affect the cost of and the demand for drilling rigs, frac crews, materials (including sand) and other equipment and related services. The availability of drilling rigs, frac crews, materials (including sand) 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 completion delays and higher well costs in that region.

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. 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.

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

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. 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.

The ability to attract and retain key members of management, qualified Board members and other key personnel is critical to the success of our business and may be challenging.

Our success will depend to a large extent upon the efforts and abilities of our management team and having experienced individuals serving on our Board who are also knowledgeable about our operations and our industry. We experienced turnover on our executive team and Board in both 2018 and 2019. If we experience similar turnover in the future, we may be unable to timely replace the talents and skills of our management team or directors if one or more did not continue serving. The success of our business also depends on other key personnel. The ability to attract and retain these key personnel may be difficult in light of the volatility of our business. We may need to enter into retention or other arrangements that could be costly to maintain. We do not maintain key-man life insurance with respect to any of our employees. Acquiring and keeping personnel could prove more difficult or cost substantially more than estimated. These factors could cause us to incur greater costs or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do. 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 adequately or 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 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.

Certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that they own.

The drilling and production of potential locations by us or other operators could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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 2019, approximately 76 percent of our total consolidated product revenues resulted from four 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 percent 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 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, and undeveloped reserves may not ultimately be converted into proved producing reserves.

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 factors and assumptions, including assumptions relating to crude oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, development costs and workover and remedial costs, the quantity, quality and interpretation of relevant data, 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 inherently uncertain, therefore, changes often occur as these variables evolve and commodity prices fluctuate. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data, and improvements or other changes in geological, geophysical and engineering evaluation methods may cause reserve estimates to change over time. Any material inaccuracies in these reserve estimates, cash flow 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, 2019, approximately 58 percent of our estimated proved reserves were proved undeveloped, compared to 62 percent at December 31, 2018. 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. Our reserve data assumes that we can and will make these significant expenditures to develop our reserves and conduct these drilling operations successfully. These assumptions, however, may not prove correct, and our estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated.

The reserve estimation standards under SEC rules 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. Accordingly, our reserve report at December 31, 2019, includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $1,136 million. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. During the year ended December 31, 2019, we wrote-off 32.1 MMBOE of proved undeveloped reserves because they are no longer expected to be developed within five years of their initial recording. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

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 based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general. 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 to approximately $1,213.9 million and $1,304.6 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. We could experience additional write-downs in the future.

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

The oil and gas industry is capital intensive. We incur and expect to continue to incur substantial capital expenditures for the acquisition, exploration and development of oil and gas reserves. We incurred approximately $370 million in acquisition, exploration and development costs during the year ended December 31, 2019. We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our credit agreement (as defined below). However, our cash flow from operations and access to capital are subject to a number of variables, including: (i) the volume of oil and gas we are able to produce from existing wells, (ii) our ability to transport our oil and gas to market, (iii) the prices at which our commodities are sold, (iv) the costs of producing oil and gas, (v) global credit and securities markets, (vi) the ability and willingness of lenders and investors to provide capital and the cost of the capital, (vii) our ability to acquire, locate and produce new reserves, (viii) the impact of potential changes in our credit ratings and (ix) our proved reserves. Additionally, a negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit agreement or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit agreements impose certain limitations on our ability to incur additional indebtedness. If we desire to issue additional debt securities other than as expressly permitted under our credit agreements, we will be required to seek the consent of the lenders in accordance with the requirements of our credit agreements, which consent may be withheld by the lenders at their discretion. 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.

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. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. 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, possible future environmental or other liabilities and the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and the assumption of 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, 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, or discover unknown liabilities after the acquisition, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the oil and gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations, financial condition and cash flows. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forgo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of oil and gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and gas leases can be generally lost and the target area can become undrillable. The failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

As a small company, we face unique difficulties competing in the larger market.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel, and we may 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 gas plays, to acquire new acreage, and to develop attractive oil and gas projects, are significant. We face intense competition in all areas of our business from companies with greater and more productive assets, greater access to capital, substantially larger staffs and greater financial and operating resources than we have. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Also, there is substantial competition for capital available for investment in the oil and gas industry. 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.

All of our operations are in the Eagle Ford Shale in South Texas, making us vulnerable to risks associated with operating in one geographic area. 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 regional supply and demand factors, 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, water shortages or other drought related conditions, plant closures for scheduled maintenance or interruption of transportation of crude oil or natural gas produced from wells in the Eagle Ford. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had $562.4 million of outstanding debt at December 31, 2019, including $362.4 million under the Company’s revolving credit agreement as amended, or the Credit Facility, and $200 million, excluding unamortized discount and issuance costs, under the $200 million Second Lien Credit Agreement, or the Second Lien Facility.

Our indebtedness and any increase in our level of indebtedness could have adverse effects on our financial condition, results of operations and cash flows, including (i) imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities, (ii) increasing the risk that we may default on our debt obligations, (iii) increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business, (iv) increasing our exposure to a rise in interest rates, which will generate greater interest expense, (v) limiting our ability to engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes and (vi) limiting our flexibility in planning for or reacting to changes in our business and industry in which we operate. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are out of our control.

Additionally, we may incur substantially more debt in the future. Our Credit Facility and the Second Lien Facility contain restrictions that limit our ability to incur indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. If we were to incur additional indebtedness without retiring existing debt, the risks described above could be magnified.

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

The borrowing base under the Credit Facility, was $500 million as of December 31, 2019. Our borrowing base is redetermined at least twice each year and is scheduled to next be redetermined in April 2020. During a borrowing base redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Credit Facility. In the event of a decline in crude oil, NGL or natural gas prices or for other reasons deemed relevant by our lenders, the borrowing base under the Credit Facility may be reduced. Additionally, the lenders may, at their discretion, initiate a redetermination at any time during the six-month period between scheduled redeterminations. 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. Furthermore, a determination to lower the borrowing base in the future to a level less than our outstanding indebtedness thereunder would require us to repay any indebtedness in excess of the redetermined borrowing base. Any such repayment or reduced access to funds could have a material adverse effect on our production, financial condition, results of operations and cash flows.

The Credit Facility and the Second Lien Facility have restrictive covenants that could limit our financial flexibility.

The Credit Facility and Second Lien Facility contain financial and other restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including leverage, interest coverage and current ratios.

The Credit Facility and the Second Lien Facility include 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 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, financial condition or cash flows. 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 or other environmental, health or safety impacts, 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. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. 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 or structures;
- pipeline ruptures or spills;
- mechanical difficulties, such as stuck oilfield drilling and service tools;
- 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, loss of well location, acreage, expected production and related reserves 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, and we may face difficulty disposing of produced water gathered from drilling and production activities.

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. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and natural gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the RRC adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Climate change legislation, laws and regulations restricting emissions of greenhouse gases or legal or other action taken by public or private entities related to climate change 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,as well as our reputation.

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 began 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*."

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, results of operations and cash flows. Reduced demand for the oil and gas that we produce could also have the effect of lowering the value of our reserves.

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 such climactic events were to occur more frequently or with greater intensity, our exploration and development activities and ability to transport our production to market could be adversely affected, as these events could cause a loss of production from temporary cessation of activity or damaged facilities and equipment. 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 - *Government Regulation and Environmental Matters*."

There have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, as well as other stakeholders, promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital and adversely impact our reputation. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Federal state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and 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 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 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. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing; an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. 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 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, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Moreover, the legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. 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 gas extraction. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil, natural gas and natural gas liquids activities utilizing injection wells for produced water disposal.

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 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 achieve more predictable cash flows and 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 commodity prices fluctuate in the future, which could have the effect of reducing our net income.

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 counterparty to a derivatives instrument fails to perform under the contract; or
- a sudden, unexpected event materially impacts commodity prices.

In addition, we may enter into derivative instruments that 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.

The adoption of derivatives legislation and implementing rules could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC, to promulgate rules and regulations implementing the Dodd-Frank Act. While some of these rules have been finalized, some have not been finalized or implemented, and it is not possible at this time to predict when this will be accomplished. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however, this initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions, though these rules have not been finalized and the impact of those provisions on us is uncertain at this time.

While the CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing, and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules subjecting any other classes of swaps, including physical commodity swaps, to mandatory clearing. Although we believe we qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to be exempt from such requirements for the mandatory exchange of margin for uncleared swaps, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Further, if we did not qualify for an exemption and were required to post collateral for our swaps, it could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Dodd-Frank Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize and restructure our existing derivatives contracts and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

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. As disclosed in Note 10 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data,” we have substantial NOL carryforwards. 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 percent shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50 percent 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, 2019, 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. In addition, U.S. NOLs generated on or after January 1, 2018, can be limited to 80 percent of taxable income. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated. Additional state taxes on oil and gas extraction may be imposed, as a result of future legislation.

In recent years, lawmakers and Treasury have proposed certain significant changes to U.S. tax laws applicable to oil and gas 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; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes are ever made, as well as any similar changes in state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our crude oil, NGLs and natural gas.

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 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, results of operations and cash flows could be adversely affected.

A cybersecurity 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 as we have experienced and will continue to experience varying degrees of cyber incidents in the normal conduct of our business.

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. These cybersecurity threat actors are becoming more sophisticated and coordinated in their attempts to access a company's information technology systems and data, including the information technology systems of cloud providers and third parties with which a company conducts business. 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.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;
- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- A cyber attack on third-party gathering, pipeline, or other transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market;
- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;
- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and
- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

Additionally, certain cyber incidents may remain undetected for an extended period. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows. Furthermore, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. The negative sentiment toward our sector versus other industry sectors has led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Such development could result in a reduction of available capital funding for potential development projects or diminution of capital to fund our business which could impact our future financial results.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many oil and gas companies, from time to time, we expect to be involved in various legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters, in the ordinary course of business. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

We emerged from bankruptcy in September 2016, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our 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 obtain credit and raise capital on terms acceptable to us or at all; and
- our ability to attract and retain customers may be negatively impacted.

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.

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.

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

The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading of our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our limited trading volume, the concentration of holdings of our common stock, 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, by significant shareholders, officers or directors could materially and adversely affect the market price of our common stock.

Our business and the trading prices of our securities could be negatively affected as a result of actions of so-called "activist" shareholders, and such activism could impact the trading value of our securities.

Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. If we become the subject of activity by activist shareholders, responding to such actions could be costly and time-consuming, diverting the attention of our management and employees. Furthermore, activist campaigns can create perceived uncertainties as to our future direction, strategy, or leadership and may result in the loss of potential business opportunities and cause our stock price to experience periods of volatility.

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, or the perception that these sales could occur, 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.

Item 1B Unresolved Staff Comments

None.

Item 2 Properties

As of December 31, 2019, our oil and gas assets were located in Gonzales, Lavaca, Fayette and Dewitt Counties in South Texas.

Facilities

Our corporate headquarters and field office facilities are leased and we believe that they 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
2019						
Developed						
Producing	40.1	8.7	41.0	55.6		
Non-producing	0.5	0.2	0.8	0.8		
	40.6	8.9	41.8	56.4		
Undeveloped	58.3	10.3	48.6	76.7		
	98.9	19.2	90.4	133.1	$ 1,488.9	$ 1,600.1
Price measurement used	$55.67/Bbl	$13.36/Bbl	$2.58/MMBtu			
2018						
Developed						
Producing	35.2	6.3	31.8	46.8		
Non-producing	—	—	—	—		
	35.2	6.3	31.8	46.8		
Undeveloped	54.5	11.7	59.7	76.2		
	89.7	18.0	91.5	123.0	$ 1,623.9	$ 1,769.4
Price measurement used	$65.56/Bbl	$23.60/Bbl	$3.10/MMBtu			
2017						
Developed						
Producing	22.4	4.9	27.2	31.8		
Non-producing	—	—	—	—		
	22.4	4.9	27.2	31.8		
Undeveloped	33.4	4.0	20.1	40.8		
	55.8	8.9	47.3	72.6	$ 590.5	$ 609.0
Price measurement used	$51.34/Bbl	$18.48/Bbl	$2.98/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. We believe that PV10 is a meaningful supplemental disclosure to the Standardized Measure as 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.

A discussion and analysis of the changes in our total proved reserves is provided in "*Supplemental Information on Oil and Gas Producing Activities (Unaudited)*" 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 five years. The following table sets forth the changes in our proved undeveloped reserves during the year ended December 31, 2019:

	Crude Oil	NGLs	Natural Gas	Oil Equivalents
	(MMBbl)	(MMBbl)	(Bcf)	(MMBOE)
Proved undeveloped reserves at beginning of year	54.5	11.8	59.7	76.2
Revisions of previous estimates	(22.7)	(4.6)	(26.5)	(31.8)
Extensions and discoveries	37.4	6.3	29.7	48.7
Purchase of reserves	0.6	—	0.2	0.7
Conversion to proved developed reserves	(11.5)	(3.2)	(14.5)	(17.1)
Proved undeveloped reserves at end of year	58.3	10.3	48.6	76.7

The marginal increase in our proved undeveloped reserves over the quantities at the end of 2018 is due primarily to substantial changes in our development plans from the southeast portion of our acreage position in the Eagle Ford to the central region. The overall shift to this region will allow us to develop wells with a lower gas content than what we experienced in the southeast region through the first half of 2019. After achieving more favorable results with certain wells in the central region, we proceeded to drill a total of 11 gross wells, or approximately 23 percent of our total wells drilled and completed in 2019, in the central region that were not considered proved undeveloped locations at the end of 2018. Accordingly, we have prioritized our drilling schedule to exploit these more favorable opportunities. While we still believe that the southeastern sites have economic merit, despite a higher gas content, we have deferred drilling them beyond the five-year window which results in revisions due to timing. Accordingly, our current five-year drilling plan is substantially weighted to the lower gas content central region.

The aforementioned shift in regional focus is reflected in the changes as follows: we experienced net negative revisions of 31.8 MMBOE including: (i) 32.1 MMBOE due to the loss of certain locations resulting from changes in the drilling locations and timing attributable to our development plans as discussed above, (ii) reductions in lateral lengths and net revenue interests of 1.7 MMBOE and (iii) declines in pricing of 1.0 MMBOE partially offset by (iv) 3.0 MMBOE due to improved performance from treatable lateral lengths in certain locations. Extensions and discoveries of 48.7 MMBOE are substantially attributable to a regional shift in our development plan, the creation of additional extended reach lateral locations and our recent leasing activities. We acquired 0.7 MMBOE in connection with the acquisition of certain non-operating partners' working interests in locations in which we are the operator. In addition, we converted 17.1 MMBOE from proved undeveloped to proved developed reserves in the Eagle Ford. During 2019, we incurred capital expenditures of approximately $254 million attributable to 38 gross (33.9 net) wells in connection with the conversion of proved undeveloped reserves to proved developed reserves. Our conversion rates for proved undeveloped reserves were 22 percent, 33 percent and 21 percent in 2019, 2018 and 2017, respectively. The conversion rate decline experienced in 2019 was impacted by the aforementioned shift in the focus of the development plan during 2019.

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 "*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 19, 2020, 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, 2019 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, Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, Inc. Our Vice President, 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. In addition to conducting these internal reviews and external reserves audits, we also have a Reserves Committee that consists of four independent members of our Board of Directors. This committee provides additional oversight of our reserves estimation and certification process.

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 Mid-Continent, which were sold in 2018, as "Divested properties." The sale of those operations represented a complete divestiture and we have retained no interests therein.

Oil and Gas Production by Region

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

	Year Ended December 31,		
Region	**2019**	**2018**	**2017**
		(MBOE)	
South Texas	10,121	7,780	3,487
Mid-Continent [1]	—	165	292
	10,121	7,944	3,779

	Average Daily Production Year Ended December 31,		
Region	**2019**	**2018**	**2017**
		(BOEPD)	
South Texas	27,730	21,314	9,553
Mid-Continent [1]	—	451	800
	27,730	21,765	10,353

[1] Mid-Continent operations were sold on July 31, 2018.

Production Prices and Production Costs

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Average prices:			
Crude oil ($ per Bbl)	$ 58.33	$ 66.23	$ 50.96
NGLs ($ per Bbl)	$ 11.13	$ 20.99	$ 19.25
Natural gas ($ per Mcf)	$ 2.51	$ 3.08	$ 2.89
Aggregate ($ per BOE)	$ 46.34	$ 55.33	$ 42.20
Average production and lifting cost ($ per BOE):			
Lease operating	$ 4.26	$ 4.52	$ 5.76
Gathering processing and transportation	2.29	2.34	2.84
	$ 6.55	$ 6.86	$ 8.60

Significant Fields

Our properties in the Eagle Ford in South Texas, which contain primarily crude oil reserves, represented all of our total equivalent proved reserves as of December 31, 2019.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Production:			
Crude oil (MBbl)	7,453	6,050	2,716
NGLs (MBbl)	1,491	944	418
Natural gas (MMcf)	7,067	4,713	2,120
Total (MBOE)	10,121	7,780	3,487
Percent of total company production	100 %	98 %	92 %
Average prices:			
Crude oil ($ per Bbl)	$ 58.33	$ 66.24	$ 51.08
NGLs ($ per Bbl)	$ 11.13	$ 21.10	$ 18.13
Natural gas ($ per Mcf)	$ 2.51	$ 3.16	$ 2.95
Aggregate ($ per BOE)	$ 46.34	$ 55.99	$ 43.74
Average production and lifting cost ($ per BOE):			
Lease operating	$ 4.26	$ 4.47	$ 5.79
Gathering processing and transportation	2.29	2.27	2.49
	$ 6.55	$ 6.74	$ 8.28

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, 2019, 2018 and 2017, 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.

	2019		**2018**		**2017**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development						
Productive	48	43.3	53	45.5	29	16.9
Dry well [1]	—	—	—	—	1	0.7
Total	48	43.3	53	45.5	30	17.6
Wells in progress at end of year [2]	8	7.3	11	10.2	11	8.2

[1] Represents the Zebra Hunter 05H well in the northern portion of our Eagle Ford acreage.
[2] Includes three gross (2.6 net) wells completing, two gross (1.9 net) wells waiting on completion and three gross (2.8 net) wells being drilled as of December 31, 2019.

Present Activities

As of December 31, 2019, we had eight gross (7.3 net) wells in progress. As of February 21, 2020, two gross (1.9 net) wells were completing and seven gross (5.5 net) wells were in progress.

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 through 2031 under gathering and transportation agreements with Nuevo Dos Gathering and Transportation, LLC and Nuevo Dos Marketing LLC. Our production and reserves are currently sufficient to fulfill the current 8,000 BOPD delivery commitment under these agreements.

Productive Wells

The following table sets forth our productive wells in which we had a working interest as of December 31, 2019:

	Primarily Oil		Primarily Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	509	429.1	1	1.0	510	430.1

Of the total wells presented in the table above, we are the operator of 498 gross (497 oil and one natural gas) and 428.2 net (427.2 oil and 1.0 natural gas) wells. In addition to the above working interest wells, we own overriding royalty interests in 18 gross wells.

Acreage

The following table sets forth our developed and undeveloped acreage as of December 31, 2019 (in thousands):

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Total acreage	91.4	79.7	8.8	7.7	100.2	87.4

The primary terms of our leases generally range from three to five years, and we do not have any concessions. As of December 31, 2019, 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 (in thousands):

	2020	2021	2022	Thereafter
Expirations by year	4.8	0.9	2.0	0.0

We anticipate paying options to extend a substantial portion of the acreage scheduled to expire in 2020. We do not believe that the remaining scheduled expirations of our undeveloped acreage will substantially affect our ability or plans to conduct our exploration and development activities.

Item 3 Legal Proceedings

See Note 14 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 threatened 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 Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Since December 28, 2016, our common stock has been listed and traded on the Nasdaq under the symbol "PVAC."

Equity Holders

As of February 13, 2020, there were 111 record holders of our common stock.

Dividends

We have not paid nor do we currently have plans to pay any cash dividends on our common stock in the foreseeable future. Furthermore, we are limited in our ability to pay dividends under the Credit Facility and the Second Lien Facility.

Securities Authorized for Issuance Under Equity Compensation Plans

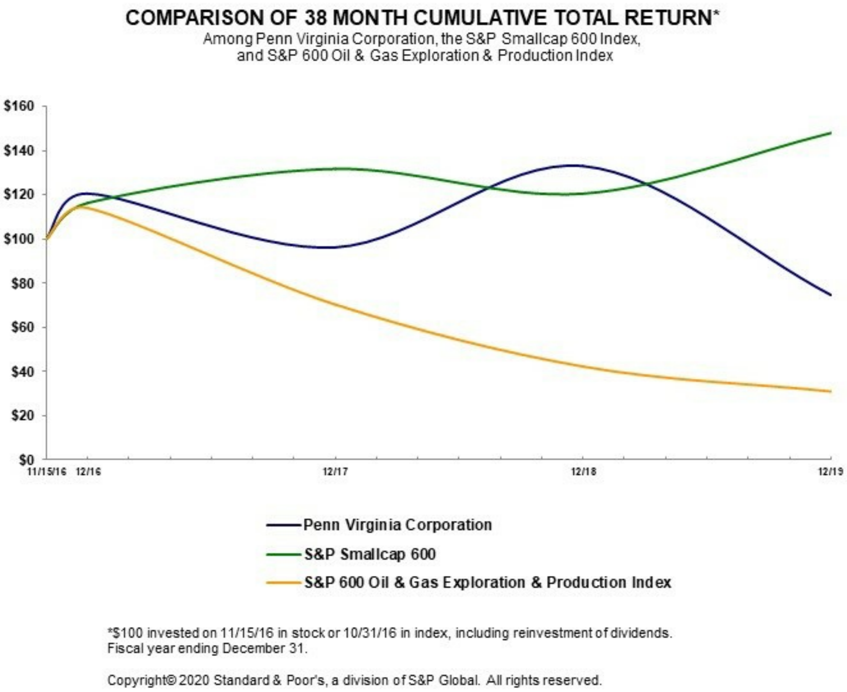
See Part III, Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and Note 16 to our Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" for information regarding shares of common stock authorized for issuance under our stock compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any shares of our common stock in the fourth quarter of2019.

Performance Graph

The following graph compares our cumulative total shareholder return with the cumulative total return of the Standard & Poor’s 600 Oil & Gas Exploration and Production Index and the Standard & Poor’s SmallCap 600 Index for the period from November 15, 2016 (the date that our common shares became publicly tradeable) through December 31, 2019. As of December 31, 2019, there were seventeen exploration and production companies in the Standard & Poor’s 600 Oil & Gas Exploration and Production Index: Bonanza Creek Energy Inc., Callon Petroleum Company, Denbury Resources Inc., Gulfport Energy Corporation, Highpoint Resources Corporation, Jagged Peak Energy, Laredo Petroleum Inc., Oasis Petroleum Inc., PDC Energy Inc., QEP Resources Inc., Range Resources Corporation, Ring Energy Inc., SM Energy Co., Southwestern Energy Company, SRC Energy Inc., Talos Energy Inc. and Whiting Petroleum Corp. The graph assumes $100 is invested on November 15, 2016 in us and each index at November 15, 2016 closing prices.



The following table represents the actual data points for the dates indicated on the graph above:

	November 15,	December 31,			
	2016	2016	2017	2018	2019
Penn Virginia Corporation	$ 100.00	$ 120.62	$ 96.27	$ 133.07	$ 74.71
S&P SmallCap 600 Index	$ 100.00	$ 116.34	$ 131.74	$ 120.56	$ 148.03
S&P 600 Oil & Gas Exploration & Production Index	$ 100.00	$ 114.11	$ 70.37	$ 42.30	$ 31.04

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.”

(in thousands, except per share amounts, production and reserves)						
	Successor [1]				Predecessor [1]	
				September 13	January 1	
	Year Ended			Through	Through	Year Ended
	December 31,			December 31,	September 12,	December 31,
	2019	2018	2017	2016	2016	2015
Statements of Operations and Other Data:						
Revenues [2]	$ 471,216	$ 440,832	$ 160,054	$ 39,003	$ 94,310	$ 305,298
Operating income (loss) [3]	$ 176,821	$ 208,755	$ 51,872	$ 11,413	$ (20,867)	$ (1,564,976)
Net income (loss) [4]	$ 70,589	$ 224,785	$ 32,662	$ (5,296)	$ 1,054,602	$ (1,582,961)
Preferred stock dividends	$ —	$ —	$ —	$ —	$ 5,972	$ 22,789
Income (loss) attributable to common shareholders	$ 70,589	$ 224,785	$ 32,662	$ (5,296)	$ 1,048,630	$ (1,605,750)
Income (loss) per common share, basic	$ 4.67	$ 14.93	$ 2.18	$ (0.35)	$ 11.91	$ (21.81)
Income (loss) per common share, diluted	$ 4.67	$ 14.70	$ 2.17	$ (0.35)	$ 8.50	$ (21.81)
Weighted-average shares outstanding:						
Basic	15,110	15,059	14,996	14,992	88,013	73,639
Diluted	15,126	15,292	15,063	14,992	124,087	73,639
Dividends declared per share	$ —	$ —	$ —	$ —	$ —	$ —
Cash provided by operating activities	$ 320,194	$ 272,132	$ 81,710	$ 30,774	$ 30,247	$ 169,303
Cash paid for capital expenditures	$ 362,743	$ 430,592	$ 115,687	$ 4,812	$ 15,359	$ 364,844
Total production (MBOE)	10,121	7,944	3,779	1,039	3,346	7,923

	December 31,				September 12,	December 31,
	2019	2018	2017	2016	2016	2015
Balance Sheet and Other Data:						
Property and equipment, net	$ 1,120,425	$ 927,994	$ 529,059	$ 247,473	$ 253,510	$ 344,395
Total assets	$ 1,218,238	$ 1,068,954	$ 629,597	$ 291,686	$ 333,974	$ 517,725
Total debt	$ 555,028	$ 511,375	$ 265,267	$ 25,000	$ 75,350	$ 1,224,383
Shareholders’ equity (deficit)	$ 520,745	$ 447,355	$ 221,639	$ 185,548	$ 190,895	$ (915,121)
Actual shares outstanding at period-end	15,136	15,081	15,019	14,992	14,992	81,253
Proved reserves as of December 31, (MMBOE)	133	123	73	49	N/A	44

1 Upon our emergence from bankruptcy, we adopted and applied fresh start accounting. Accordingly, our financial statements for periods after September 12, 2016 are not comparable to those prior to that date. Financial information for the periods up to and including September 12, 2016 are referred to herein as those of the “Predecessor” while those beginning on September 13, 2016 and all periods thereafter are referenced as those of the “Successor.”

2 Revenues for the years ended after December 31, 2017 reflect the application of Accounting Standards Codification, or ASC, Topic 606, *Revenues from Contracts with Customers*, or ASC Topic 606. The adoption of ASC Topic 606 impacts the presentation and comparability of NGL product revenues between the years beginning after December 31, 2017 with those years ending on that date and all prior periods. See “*Presentation of Financial Information and Changes in Accounting Principles* ” included in Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 2 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data.”

3 Operating income (loss) for the year ended December 31, 2019 reflects the application of ASC Topic 842, *Leases*, or ASC Topic 842. The adoption of ASC Topic 842 impacts the presentation and comparability of lease expense between the year ended December 31, 2019 with all prior periods. See “*Presentation of Financial Information and Changes in Accounting Principles* ” included in Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and Note 2 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data.”

3 Net income (loss) and Income (loss) attributable to common shareholders for the year ended December 31, 2018 and the period of January 1 through September 12, 2016 includes reorganization items resulting in income attributable to our bankruptcy proceedings of $3.3 million and $1.1 billion, respectively.

Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations

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 of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford, in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

Industry Environment and Recent Operating and Financial Highlights

Commodity Price and Other Economic Conditions

Crude oil prices exhibited significant volatility throughout 2019 with a range between high and low prices of approximately $20 per barrel. This volatility has continued into February of 2020 and has included significant swings on a daily basis. In addition to the traditional domestic (i.e., significant production from the Permian Basin and mature shale plays including the Eagle Ford, etc.) and global (i.e., Middle East capacity, etc.) supply and demand factors, the impact of certain geopolitical and other dynamics have had a significant daily impact on crude oil and other commodity prices as well. For example, Middle East tensions have approached levels with military involvement not experienced in many years. In addition, the global economic impact of the coronavirus is continuing to evolve and its uncertainty has been reflected in daily commodity price volatility. While impacting us to a lesser extent, NGL and natural gas pricing has steadily declined from year-end 2018 levels due primarily to excess domestic supply and milder winter weather through January of 2020. Collectively, these trends have had a substantial impact on the rate of growth in our product revenues. These factors are anticipated to maintain downward pressure on commodity prices for the near term.

Since February 2019, we have contracted for our drilling rigs on a pad-to-pad basis and the day rates charged for these services as well as casing costs have declined throughout 2019. In addition, costs associated with our dedicated frac services agreement including certain component stimulation product and service costs have also declined in 2019. We anticipate that many of these costs will continue a declining trend into 2020. Costs incurred for most oilfield products and services associated with operating our properties remained relatively stable during 2019 and are anticipated to behave similarly into 2020 with moderate declines in certain costs consistent with recent industry experience.

Capital Expenditures and Development Progress

During 2019, we incurred capital expenditures of approximately $356 million with 97 percent directed to drilling and completion projects. We drilled and completed a total of 48 gross (43.3 net) wells. In a series of transactions, we acquired certain of our joint venture partners' working interests in selected properties for which we are the operator for approximately $6.5 million. Through our drilling program and these acquisitions, we operated a total of 510 gross (430.1 net) wells in the Eagle Ford as of December 31, 2019. Through selected acquisitions, certain property exchanges and other transactions, we added or renewed approximately 3,500 net acres to our Eagle Ford lease portfolio during 2019.

Sequential Quarterly Analysis

The following summarizes certain key operating and financial highlights for the three months ended December 31, 2019 with comparison to the three months ended September 30, 2019 as presented in the table that follows. The year-over-year highlights for 2019 and 2018 are addressed in further detail in the discussions for *Financial Condition* and *Results of Operations* that follow.

- Daily production increased one percent to 29,314 BOEPD, from 29,003 BOEPD due primarily to the number of wells turned to sales in the second half of 2019. During the fourth quarter of 2019, we turned to sales 11 gross (9.9 net) wells compared to 20 gross (18.3 net) wells turned to sales in the third quarter of 2019. Of the wells turned to sales in the third quarter of 2019, ten gross (9.0 net) wells were turned to sales in late August and September of 2019. Total production increased one percent to 2,697 MBOE from 2,668 MBOE.
- Product revenues increased approximately four percent to $123.2 million from $118.4 million due primarily to six percent higher crude oil volume partially offset by one percent lower crude oil prices. NGL revenues were 13 percent higher due to 26 percent higher prices partially offset by 10 percent lower volume. Natural gas revenues declined six percent due to an 11 percent decrease in volume partially offset by a five percent increase in prices.
- Production and lifting costs (consisting of LOE and GPT) declined on an absolute and per unit basis to $16.1 million and $5.98 per BOE from $18.5 million and $6.92 per BOE due primarily to lower utility charges, maintenance costs and chemical costs.

- Production and ad valorem taxes were relatively consistent on an absolute basis at $7.4 million for each period and declined marginally on per unit basis to $2.74 per BOE from $2.77 per BOE, respectively, due to three percent lower overall product pricing and one percent higher production volume partially offset by the effect of higher estimated valuations for ad valorem tax assessments that were recorded in prior quarters of 2019.
- G&A expenses decreased on an absolute and per unit basis to $5.3 million and $1.97 per BOE from $6.9 million and $2.57 per BOE, respectively, due primarily to lower benefits charges as well as lower occupancy and consulting costs.
- Our DD&A, decreased on an absolute basis and per unit basis to $44.9 million and $16.64 per BOE from $46.5 million and $17.43 per BOE due primarily to higher reserve quantity estimates.
- Our operating income increased to $50.2 million from $40.0 million due to the combined impact of the matters noted in the bullets above.

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

	(in thousands except per unit measurements, production, wells and reserves)				
	Three Months Ended				
	December 31,	September 30,	Year Ended December 31,		
	2019	2019	2019	2018	2017
Total production (MBOE)	2,697	2,668	10,121	7,944	3,779
Average daily production (BOEPD)	29,314	29,003	27,730	21,765	10,353
Crude oil production (MBbl)	2,043	1,937	7,453	6,077	2,764
Crude oil production as a percent of total	76%	73%	74%	76%	73%
Product revenues	$ 123,196	$ 118,379	$ 469,035	$ 439,530	$ 159,469
Crude oil revenues	$ 115,252	$ 110,618	$ 434,713	$ 402,485	$ 140,886
Crude oil revenues as a percent of total	94%	93%	93%	92%	88%
Realized prices:					
Crude oil ($ per Bbl)	$ 56.40	$ 57.12	$ 58.33	$ 66.23	$ 50.96
NGL ($ per Bbl) [1]	$ 10.74	$ 8.54	$ 11.13	$ 20.99	$ 19.25
Natural gas ($ per Mcf)	$ 2.34	$ 2.22	$ 2.51	$ 3.08	$ 2.89
Aggregate ($ per BOE)	$ 45.68	$ 44.37	$ 46.34	$ 55.33	$ 42.20
Prices, adjusted for derivatives::					
Crude oil ($ per Bbl)	$ 56.50	$ 56.90	$ 57.78	$ 58.28	$ 49.69
Aggregate ($ per BOE)	$ 45.75	$ 44.21	$ 45.93	$ 49.25	$ 41.27
Production and lifting costs ($ per BOE):					
Lease operating	$ 3.65	$ 4.45	$ 4.26	$ 4.52	$ 5.76
Gathering, processing and transportation [1]	$ 2.32	$ 2.47	$ 2.29	$ 2.34	$ 2.84
Production and ad valorem taxes ($ per BOE)	$ 2.74	$ 2.77	$ 2.77	$ 2.96	$ 2.33
General and administrative ($ per BOE) [2]	$ 1.97	$ 2.58	$ 2.52	$ 3.28	$ 4.82
Depreciation, depletion and amortization ($ per BOE)	$ 16.64	$ 17.43	$ 17.25	$ 16.11	$ 12.87
Capital expenditure program costs [3]	$ 64,623	$ 99,068	$ 355,851	$ 418,951	$ 129,827
Cash provided by operating activities [4]	$ 75,981	$ 89,851	$ 320,194	$ 272,132	$ 81,710
Cash paid for capital expenditures [5]	$ 71,010	$ 115,792	$ 362,743	$ 430,592	$ 115,687
Cash and cash equivalents at end of period	$ 7,798	$ 11,387	$ 7,798	$ 17,864	$ 11,017
Debt outstanding, net of discount and issue costs, at end of period	$ 555,028	$ 562,445	$ 555,028	$ 511,375	$ 265,267
Credit available under credit facility at end of period	$ 137,200	$ 129,200	$ 137,200	$ 128,600	$ 159,745
Net development wells drilled and completed	9.9	18.3	43.3	45.5	16.9
Proved reserves at the end of the period (MMBOE)	133	N/A	133	123	73

[1] The effects of the adoption of ASC Topic 606, if applied to the year ended December 31, 2017, would have resulted in realized prices for NGLs of $16.40 per BOE and GPT of $2.45 per BOE, respectively.

[2] Includes combined amounts of $0.36 and $0.39 per BOE for the three months ended December 31, 2019 and September 30, 2019, respectively, and $0.48, $1.11 and 1.36 per BOE for the years ended December 31, 2019, 2018 and 2017, respectively, attributable to equity-classified share-based compensation and significant special charges, including acquisition, divestiture and strategic transaction costs, among others costs, as described in the discussion of "*Results of Operations - General and Administrative* " that follows.

[3] Includes amounts accrued and excludes capitalized interest and capitalized labor.

[4] Includes net cash received for derivative settlements of $0.2 million and net cash paid for derivative settlements of $0.4 million for the three months ended December 31, 2019 and September 30, 2019, respectively, and net cash paid for derivative settlements of $4.1 million, $48.3 million and $3.5 million for the years ended December 31, 2019, 2018 and 2017, respectively. Reflects changes in operating assets and liabilities of $(12.7) million and $10.9 million for the three months ended December 31, 2019 and September 30, 2019, respectively, and $0.2 million, $(2.8) million and $(15.0) million for the years ended December 31, 2019, 2018 and 2017, respectively.

[5] Represents actual cash paid for capital expenditures including capitalized interest and capitalized labor.

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:

Production and Development Progress

Total production for the quarter and year ended December 31, 2019 was 2,697 MBOE and 10,121, or 29,314 and 27,730 BOEPD, with approximately 76 percent and 74 percent, or 2,043 MBbls and 7,453 MBbls, of production from crude oil, 14 and 15 percent from NGLs and 10 percent and 11 percent from natural gas, respectively.

We drilled and turned 11 and 48 gross (9.9 and 43.3 net) wells to sales during the quarter and year ended December 31, 2019, respectively. Subsequent to December 31, 2019, we turned an additional six gross (5.4 net) wells to sales through February 21, 2020. As of February 21, 2020, we were in the process of drilling seven gross (5.5 net) wells and two gross (1.9 net) wells were completing.

As of February 21, 2020, we had approximately 100,200 gross (87,400 net) acres in the Eagle Ford, net of expirations. Approximately 91 percent of our acreage is held by production and substantially all is operated by us.

Commodity and Interest Rate Hedging Program

As of January 31, 2020 and including hedges we entered into after December 31, 2019, we have hedged a portion of our estimated future crude oil and natural gas production from February 1, 2020 through the end of 2021 with a mix of WTI- , MEH-, and Henry Hub indexed swaps, enhanced swaps and collars. We are currently unhedged with respect to NGL production. The following table summarizes our hedge positions for the periods presented:

Swaps	WTI - Oil Volumes (Barrels per day)	WTI Average Price ($ per barrel)		MEH - Oil Volumes (Barrels per day)	MEH Average Price ($ per barrel)	
1Q - 2020	15,648	$	55.34	2,000	$	61.03
2Q - 2020	10,648	$	55.35	2,000	$	61.03
3Q - 2020	8,630	$	55.20	2,000	$	61.03
4Q - 2020	8,630	$	55.20	2,000	$	61.03
1Q - 2021	3,333	$	55.89	—	$	—
2Q - 2021	3,297	$	55.89	—	$	—
3Q - 2021	1,630	$	55.50	—	$	—
4Q - 2021	1,630	$	55.50	—	$	—

Collars	WTI - Oil Volumes (Barrels per day)	WTI Floor Price ($ per barrel)		WTI Ceiling Price ($ per barrel)	
2Q - 2020	5,297	$	52.36	$	57.60
3Q - 2020	6,891	$	52.97	$	58.03
4Q - 2020	2,000	$	48.00	$	57.10
1Q - 2021	1,667	$	55.00	$	58.00
2Q - 2021	1,648	$	55.00	$	58.00

Sold Puts	WTI - Oil Volumes (Barrels per day)	WTI Put Price ($ per barrel)	
1Q - 2021	5,000	$	44.00
2Q - 2021	4,945	$	44.00
3Q - 2021	1,630	$	44.00
4Q - 2021	1,630	$	44.00

As of January 31, 2020, we have hedged over 40% of our estimated 2020 natural gas production.

Collars	Henry Hub - Gas Volumes (MMBtu/d)	Henry Hub Floor Price ($/MMBtu)		Henry Hub Ceiling Price ($/MMBtu)	
1Q - 2020	5,934	$	2.00	$	2.18
2Q - 2020	8,901	$	2.00	$	2.18
3Q - 2020	8,804	$	2.00	$	2.18
4Q - 2020	8,804	$	2.00	$	2.18

In February 2020, we began hedging our exposure to variable interest rates as we entered into a series of interest rate swaps contracts through May 2022 for a notional amount of $300 million, paying a weighted-average fixed rate of 1.36%.

Amendment to Credit Facility and Affirmation of Borrowing Base

In May 2019, we entered into the Borrowing Base Increase Agreement and Amendment No. 6 to the Credit Facility, or the Sixth Amendment, to our credit agreement, or Credit Facility, increasing the lender commitment to $1.0 billion from $450 million and the borrowing base to $500 million from $450 million and extending the maturity to May 2024 from September 2020 (subject to certain conditions as described in Note 9 to our Consolidated Financial Statements included in Part II, Item 8, “Financial Statements and Supplementary Data,”) among other things. In addition, the applicable margin ranges associated with borrowings under the Credit Facility were each reduced by 150 basis points. We incurred and capitalized approximately $2.6 million of issue and other costs associated with the Sixth Amendment.

In November 2019, we completed our fall borrowing base redetermination and our lenders affirmed the $500 million borrowing base. Our next redetermination is currently scheduled for April 2020.

Executive Transition

On November 4, 2019, the Company announced that Russell T Kelley, Jr. had been appointed as the Company’s Senior Vice President, Chief Financial Officer and Treasurer, or SVP and CFO, effective November 13, 2019. In connection with the transition, Steven A. Hartman, the former SVP and CFO resigned in accordance with a separation and transition agreement with the Company.

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 $1.0 billion in borrowing commitments. The current borrowing base under the Credit Facility is also $500 million. As of February 27, 2020, we had $133.2 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 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. In order to mitigate this volatility, we entered into derivative contracts with a number of financial institutions, all of which are participants in the Credit Facility, hedging a portion of our estimated future crude oil production through the end of 2021. The level of our hedging activity and duration of the financial instruments employed depend on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

Capital Resources

Under our capital program for 2020, we anticipate capital expenditures, excluding acquisitions, of up to $310 million with approximately 95 percent of capital being directed to drilling and completions on our Eagle Ford acreage. We plan to fund our 2020 capital spending primarily with cash from operating activities and, to the extent necessary, supplemental borrowings under the Credit Facility. Based upon current price and production expectations for 2020, we believe that our cash from operating activities and borrowings under our Credit Facility, as necessary, will be sufficient to fund our operations through year-end 2020; 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. 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 February 27, 2020, we had over $15 million of cash on hand. For additional information and an analysis of our historical cash flows from operating activities, see the "*Cash Flows*" discussion that follows.

Credit Facility Borrowings. During 2019, we borrowed $41.4 million, net of repayments, under the Credit Facility. 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			
	End of Period	**Weighted-Average**	**Maximum**	**Weighted-Average Rate**
Three months ended December 31, 2019	$ 362,400	$ 381,465	$ 384,400	4.06%
Year ended December 31, 2019	$ 362,400	$ 349,713	$ 384,400	4.79%

Proceeds from Sales of Assets. We continually evaluate potential sales of assets, including certain non-strategic oil and gas properties and 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 Markets 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:

	Year Ended December 31,	
	2019	2018
Cash flows from operating activities		
Operating cash flows, net of working capital changes	$ 356,321	$ 346,780
Crude oil derivative settlements paid, net	(4,136)	(48,291)
Interest payments, net of amounts capitalized	(32,398)	(22,599)
Income tax refunds	2,471	—
Acquisition, divestiture and strategic transaction costs paid	(1,985)	(2,968)
Reorganization-related administration fees and costs paid, net	(79)	(540)
Consulting costs paid to former Executive Chairman	—	(250)
Net cash provided by operating activities	320,194	272,132
Cash flows from investing activities		
Acquisitions, net	(6,516)	(85,387)
Capital expenditures	(362,743)	(430,592)
Proceeds from sales of assets, net	215	7,683
Net cash used in investing activities	(369,044)	(508,296)
Cash flows from financing activities		
Proceeds from credit facility borrowings, net	41,400	244,000
Debt issuance costs paid	(2,616)	(989)
Net cash provided by financing activities	38,784	243,011
Net increase (decrease) in cash and cash equivalents	$ (10,066)	$ 6,847

Cash Flows from Operating Activities. The increase of $48.1 million in net cash from operating activities for2019 compared to 2018 was primarily attributable to: (i) approximately 27 percent higher production volume in 2019 despite approximately 16 percent lower overall product pricing, (ii) substantially lower net payments of derivative settlements during 2019 resulting primarily from the narrowing of the margin between hedged and actual settlement prices, (iii) the receipt in 2019 of a refund of alternative minimum tax, or AMT, credits in connection with the filing of our 2018 federal income tax return, (iv) lower payments in 2019 for acquisition, divestiture and strategic transaction costs as a merger agreement was terminated in early 2019, (v) lower bankruptcy-related administration costs as the case was closed in November 2018 and (vi) less executive retirement costs in 2019 compared to 2018. These items were partially offset by higher interest payments due to greater outstanding borrowings in 2019.

Cash Flows from Investing Activities. In 2019, we paid $6.5 million for the acquisition of working interests in certain properties for which we are the operator from our joint working interest partners. In 2018, we paid a combined total of $86.5 million for the Hunt Acquisition and the purchase of other working interests in producing properties in the Eagle Ford and received a total of $1.1 million in connection with the final settlement of the Devon Acquisition. As illustrated in the tables below, our cash payments for capital expenditures were significantly lower during 2019 as compared to 2018, due primarily to the employment of two drilling rigs through most of 2019 compared to three drilling rigs utilized during most of 2018. The cash payments for capital expenditures for 2019 and 2018 also reflect refunds of $3.8 million and $0.6 million, respectively, received for sales and use taxes that were applicable to capital expenditures in prior years. In addition, we received $0.2 million in proceeds from the sale of scrap tubular and well materials in 2019 while we received proceeds of $7.7 million in 2018 attributable to the sales of: (i) all of our Mid-Continent properties, (ii) undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana, (iii) certain undeveloped deep leasehold rights in Oklahoma, (iv) certain pipeline assets in our former Marcellus Shale operating region and (iv) scrap tubular and well materials.

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

	Year Ended December 31,	
	2019	2018
Drilling and completion	$ 344,542	$ 405,677
Lease acquisitions and other land-related costs	3,433	5,180
Geological, geophysical (seismic) and delay rental costs	363	377
Pipeline, gathering facilities and other equipment, net	7,513	7,717
	$ 355,851	$ 418,951

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:

	Year Ended December 31,	
	2019	2018
Total capital expenditures program costs (from above)	$ 355,851	$ 418,951
Decrease (increase) in accrued capitalized costs	3,602	(44)
Less:		
Transfers from tubular inventory and well materials	(10,971)	(10,056)
Sales & use tax refunds received and applied to property accounts	(3,816)	(643)
Other, net	(115)	—
Add:		
Tubular inventory and well materials purchased in advance of drilling	9,967	9,578
Capitalized internal labor	4,089	3,688
Capitalized interest	4,136	9,118
Total cash paid for capital expenditures	$ 362,743	$ 430,592

Cash Flows from Financing Activities. During 2019, we borrowed $76.4 million and made repayments of $35.0 million under the Credit Facility which were used to fund a portion of our capital program as well as the aforementioned acquisition of working interests. During 2018, we borrowed $244 million under the Credit Facility to fund the three-rig capital program and the Hunt Acquisition. We also paid $2.6 million and $1.0 million of debt issue costs in 2019 and 2018, respectively, in connection with amendments to the Credit Facility.

Capitalization

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

	December 31,	
	2019	2018
Credit Facility borrowings	$ 362,400	$ 321,000
Second Lien Facility term loans, net of original issue discount and issuance costs	192,628	190,375
Total debt	555,028	511,375
Shareholders’ equity	520,745	447,355
Total capitalization	$ 1,075,773	$ 958,730
Debt as a % of total capitalization	52 %	53 %

Credit Facility. The Credit Facility provides for a $1.0 billion revolving commitment and $500 million borrowing base, including a $25.0 million sublimit for the issuance of letters of credit. The availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is redetermined semi-annually, generally in April and October of each year. Additionally, 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 for general corporate purposes including working capital. We had $0.4 million in letters of credit outstanding as of December 31, 2019 and 2018, respectively.

The Credit Facility is scheduled to mature in May 2024; provided that on June 30, 2022, unless we have either extended the maturity date of our $200 million Second Lien Credit Agreement dated as of September 29, 2017, or the Second Lien Facility, to a date that is at least 91 days after May 7, 2024 or have repaid our Second Lien Facility in full, the maturity date of the Credit Facility will mean June 30, 2022.

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 0.50% to 1.50%, determined based on the average availability under the Credit Facility or (b) a customary London interbank offered rate, or LIBOR, plus an applicable margin ranging from 1.50% to 2.50%, 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 our election, and is computed on the basis of a year of 360 days. As of December 31, 2019, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 3.75%. Unused commitment fees are charged at a rate of 0.375% to 0.50%, depending upon utilization.

The Credit Facility is guaranteed by us 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. There are no significant restrictions on our ability 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.

Second Lien Facility. On September 29, 2017, we entered into the $200 million Second Lien Facility. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. As of December 31, 2019, the actual interest rate on outstanding borrowings under the Second Lien Facility was 8.81%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. 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 or three months (including in three month intervals if we select a six-month interest period), at our election and is computed on the basis of a year of 360 days. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following remaining prepayment premiums (in addition to customary “breakage” costs with respect to eurocurrency loans): during the period ending September 29, 2020, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following remaining prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility: during the period ended September 29, 2020, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company’s and its subsidiaries’ assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Guarantor Subsidiaries.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the the unused portion of the total commitment as a current asset) of 1.00 to 1.00, and (2) a maximum leverage ratio (consolidated indebtedness to EBITDAX, each as defined in the Credit Facility), in each case measured as of the last day of each fiscal quarter of 4.00 to 1.00. The Second Lien Facility has no financial covenants.

The Credit Facility and Second Lien Facility also contain 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), limitations on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility and Second Lien Facility contain customary events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility and Second Lien Facility, as applicable, the lenders thereto may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility and Second Lien Facility.

As of December 31, 2019, we were in compliance with all of the covenants under the Credit Facility and the Second Lien Facility.

Reference Rate Reform. In July 2017, the U.K.’s Financial Conduct Authority, which regulates LIBOR, announced that it intends to phase out LIBOR by the end of 2021. At the present time, the Credit Facility and Second Lien Facility are, at our option, contractually subject to LIBOR rates and both have terms that extend beyond 2021. We have not yet pursued any technical amendment or other contractual alternative to address this matter. We are currently evaluating the potential impact of the eventual replacement of the LIBOR interest rate.

Results of Operations

Presentation of Financial Information and Changes in Accounting Principles

Adoption of New Accounting Standards

As discussed in further detail in Notes 2, 5 and 11 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data," we have adopted two accounting standards that impact the comparability of our financial statements: Accounting Standards Codification, or ASC, Topic 842, *Leases*, or ASC Topic 842, effective January 1, 2019 and ASC Topic 606, *Revenues from Contracts with Customers*, or ASC Topic 606, effective January 1, 2018. The adoption of ASC Topic 842 impacts the presentation and comparability of (i) Lease operating, or LOE, expense and (ii) General and administrative, or G&A, expenses. We adopted ASC Topic 842 utilizing the cumulative effect transition method effective January 1, 2019. Accordingly, our LOE and G&A expenses for the year ended December 31, 2019 are not comparable to the 2018 and 2017 presentation of these items. The adoption of ASC Topic 606 impacts the presentation and comparability of (i) NGL product revenues and (ii) Gathering, processing and transportation, or GPT, expense. We adopted ASC Topic 606 utilizing the cumulative effect transition method effective January 1, 2018. Accordingly, our NGL revenues and GPT expense for the year ended December 31, 2017 are not comparable to the 2019 and 2018 presentation of these items. Our discussion and analysis of these items in the *Results of Operations* that follow address the effects of changes directly attributable to the adoption of ASC Topic 842 and ASC Topic 606.

Impact of Acquisitions and Divestitures

A portion of the components of our year-over-year variances for 2018 to 2017 are also due to the effects of the Hunt Acquisition in March 2018 and the Devon Acquisition in September 2017. Partially offsetting the impact of these transactions are the effects of our divestiture of our former assets in the Mid-Continent region that we sold in July 2018.

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		
	Year Ended December 31,		
	2019	2018	2017
Crude oil (MBbl)	7,453	6,077	2,764
NGLs (MBbl)	1,491	1,004	523
Natural gas (MMcf)	7,067	5,181	2,949
Total (MBOE)	10,121	7,944	3,779
2019 vs 2018 Variance (MBOE)		2,177	
% Change		27%	
2018 vs. 2017 Variance (MBOE)			4,165
% Change			110%

	Average Daily Production		
	Year Ended December 31,		
	2019	2018	2017
Crude oil (Bbl per day)	20,418	16,650	7,573
NGLs (Bbl per day)	4,085	2,750	1,432
Natural gas (MMcf per day)	19	14	8
Total (BOEPD)	27,730	21,765	10,353
2019 vs 2018 Variance (BOEPD)		5,965	
% Change		27%	
2018 vs. 2017 Variance (BOEPD)			11,412
% Change			110%

	Total Production by Region		
	Year Ended December 31,		
	2019	2018	2017
South Texas	10,121	7,780	3,487
Mid-Continent [1]	—	165	292
Total (MBOE)	10,121	7,944	3,779
2019 vs 2018 Variance (MBOE)		2,177	
% Change		27 %	
2018 vs. 2017 Variance (MBOE)			4,165
% Change			110 %

	Average Daily Production by Region		
	Year Ended December 31,		
	2019	2018	2017
South Texas	27,730	21,314	9,553
Mid-Continent [1]	—	451	800
Total (BOEPD)	27,730	21,765	10,353
2019 vs 2018 Variance (BOEPD)		5,965	
% Change		27 %	
2018 vs. 2017 Variance (BOEPD)			11,412
% Change			110 %

[1] Mid-Continent operations were sold on July 31, 2018.

2019 vs. 2018. Total production increased 27 percent during 2019 compared to 2018 due primarily to a greater number of higher working interest wells turned to sales in the fourth quarter of 2018 through December 31, 2019 when compared to the corresponding periods from the fourth quarter of 2017 through December 31, 2018 as well as the effect of a full year of production from the Hunt Acquisition. These increases were partially offset by the effect of the divestiture in July 2018 of our former Mid-Continent operations, as well as natural production declines from our more mature Eagle Ford wells.

We operated two drilling rigs during the majority of 2019 compared to three during the majority of 2018. During 2019, we turned 48 gross (43.3 net) wells to sales compared to 53 gross (45.5 net) wells during 2018. When considering the wells turned to sales in the fourth quarters of the prior years for which we would receive a full year of subsequent production, we had 58 gross (52.2 net) wells for the year ended December 31, 2019 as compared to 62 gross (50.8 net) wells for the year ended December 31, 2018.

Approximately 74 percent of total production during 2019 was attributable to crude oil when compared to approximately 76 percent during 2018. The decline in the crude oil composition of total production was due primarily to a higher gas content experienced with some of our recently drilled wells, primarily in the southeastern portion of our acreage holdings.

2018 vs. 2017. Total production increased 110 percent during 2018 compared to 2017 due primarily to a greater number of wells turned to sales in 2018 under an expanded drilling program as well as incremental production from the Hunt and Devon Acquisitions. We operated three drilling rigs during 2018 compared to two during 2017, the second of which was not contracted until mid-March 2017. These increases were partially offset by the effect of the divestiture in July 2018 of our former Mid-Continent operations, as well as natural production declines from our more mature Eagle Ford wells.

Approximately 76 percent of total production during 2018 was attributable to crude oil when compared to approximately 73 percent during 2017. Our Eagle Ford production represented 98 percent of our total production during 2018 compared to approximately 92 percent from this region during 2017. Subsequent to the sale of our Mid-Continent properties on July 31, 2018, the entirety of our production was derived from the Eagle Ford. During 2018, we turned 53 gross (45.5 net) Eagle Ford wells to sales compared to 29 gross (16.9 net) wells during 2017.

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:

	Total Product Revenues Year Ended December 31,		
	2019	2018	2017
Crude oil	$ 434,713	$ 402,485	$ 140,886
NGLs	16,589	21,073	10,066
Natural gas	17,733	15,972	8,517
Total	$ 469,035	$ 439,530	$ 159,469
2019 vs. 2018 Variance		$ 29,505	
% Change		7 %	
2018 vs. 2017 Variance			$ 280,061
% Change			176 %

	Product Revenues per Unit of Volume Year Ended December 31,		
	2019	2018	2017
Crude oil ($ per barrel)	$ 58.33	$ 66.23	$ 50.96
NGLs ($ per barrel)	$ 11.13	$ 20.99	$ 19.25
Natural gas ($ per Mcf)	$ 2.51	$ 3.08	$ 2.89
Total ($ per BOE)	$ 46.34	$ 55.33	$ 42.20
2019 vs. 2018 Variance ($ per BOE)		$ (8.99)	
% Change		(16)%	
2018 vs. 2017 Variance ($ per BOE)			$ 13.13
% Change			31 %

	Product Revenues by Region Year Ended December 31,		
	2019	2018	2017
South Texas	$ 469,035	$ 435,599	$ 152,521
Divested properties [1]	—	3,931	6,948
Total	$ 469,035	$ 439,530	$ 159,469
2019 vs. 2018 Variance		$ 29,505	
% Change		7 %	
2018 vs. 2017 Variance			$ 280,061
% Change			176 %

	Product Revenues per BOE by Region Year Ended December 31,		
	2019	2018	2017
South Texas	$ 46.34	$ 55.99	$ 43.74
Divested properties [1]	$ —	$ 23.87	$ 23.79
Total ($ per BOE)	$ 46.34	$ 55.33	$ 42.20
2019 vs. 2018 Variance ($ per BOE)		$ (8.99)	
% Change		(16)%	
2018 vs. 2017 Variance ($ per BOE)			$ 13.13
% Change			31 %

[1] Mid-Continent operations were sold on July 31, 2018.

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

	Year Ended December 31, 2019 vs. Year Ended December 31, 2018			Year Ended December 31, 2018 vs. Year Ended December 31, 2017		
	Revenue Variance Due to			Revenue Variance Due to		
	Volume	Price	Total	Volume	Price	Total
Crude oil	$ 91,108	$ (58,880)	$ 32,228	$ 168,812	$ 92,787	$ 261,599
NGLs	10,227	(14,711)	(4,484)	9,259	1,748	11,007
Natural gas	5,815	(4,054)	1,761	6,448	1,007	7,455
	$ 107,150	$ (77,645)	$ 29,505	$ 184,519	$ 95,542	$ 280,061

2019 vs. 2018. Our product revenues increased seven percent during 2019 over 2018 due primarily to approximately 23 percent higher crude oil volumes partially offset by 12 percent lower crude oil pricing resulting in higher overall product revenues. NGL revenues declined approximately 21 percent in 2019 due to substantially lower pricing (47 percent) partially offset by approximately 49 percent higher volumes. Natural gas revenues increased approximately 11 percent due primarily to approximately 36 percent higher volumes substantially offset by approximately 19 percent lower pricing. Crude oil revenues were approximately 93 percent of our total revenues during 2019 as compared to approximately 92 percent during 2018.

2018 vs. 2017. Our product revenues increased 176 percent during 2018 over 2017 due primarily to approximately 120 percent higher crude oil volumes, 92 percent higher NGL volumes and 76 higher natural gas volumes as well as the effect of 30 percent higher crude oil prices and approximately seven percent higher natural gas prices. Excluding the $2.4 million effect of the adoption of ASC Topic 606, NGL pricing increased by 21 percent during 2018 as compared to 2017. Crude oil revenues were approximately 92 percent of our total revenues during 2018 compared to 88 percent during 2017. Total Eagle Ford revenues were approximately 99 percent of total revenues in 2018 and 96 percent during 2017. Effective August 2018, all of our revenues were derived from the Eagle Ford.

Realized Differentials

The following table reconciles our realized price differentials from weighted-average NYMEX-quoted prices for WTI crude oil for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Realized crude oil prices per barrel	$ 58.33	$ 66.23	$ 50.96
Weighted-average WTI prices	57.04	65.56	51.34
Realized differential to WTI per barrel	$ 1.29	$ 0.67	$ (0.38)

We have realized premiums to the WTI index price for crude oil over the past two years as the majority of our production during those periods was sold based on LLS or MEH index pricing due to the proximity of our operating region to the Gulf Coast markets.

Effects of Derivatives

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

	Year Ended December 31,		
	2019	2018	2017
Crude oil revenues as reported	$ 434,713	$ 402,485	$ 140,886
Derivative settlements, net	(4,136)	(48,291)	(3,511)
	$ 430,577	$ 354,194	$ 137,375
Crude oil prices per Bbl, as reported	$ 58.33	$ 66.23	$ 50.96
Derivative settlements per Bbl	(0.55)	(7.95)	(1.27)
	$ 57.78	$ 58.28	$ 49.69

Gain (Loss) on Sales of Assets

We recognize gains and losses on the sale or disposition of assets other than our oil and gas properties upon the completion of the underlying transactions. The following table sets forth the total gains and losses recognized for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Gain (loss) on sales of assets, net	$ 5	$ (177)	$ (36)

2019, 2018 and 2017. In 2019, 2018 and 2017, we recognized insignificant net gains and losses attributable to sale or trade of certain support equipment and surplus and scrap tubular inventory and well materials.

Other Revenues, Net

Other revenues, net, includes fees for marketing and water disposal services that we charge to third parties, net of related expenses as well as other miscellaneous revenues and credits attributable to our current operations.

The following table sets forth the total other revenues, net for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Other revenues, net	$ 2,176	$ 1,479	$ 621

2019 vs. 2018. Other revenues, net increased during 2019 from 2018 due primarily to higher water disposal revenues attributable to higher production partially offset by certain unscheduled repairs and maintenance costs incurred during the second quarter of 2019 at our water disposal facilities

2018 vs. 2017. Other revenues, net increased during 2018 from 2017 due primarily to higher marketing fees charged to third parties resulting from substantially higher production.

Lease Operating Expenses

LOE include 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.

The following table sets forth our LOE for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Lease operating	$ 43,088	$ 35,879	$ 21,784
Per unit of production ($/BOE)	$ 4.26	$ 4.52	$ 5.76

2019 vs. 2018. LOE increased on an absolute basis, but declined on a per unit basis during 2019 when compared to 2018 due primarily to the overall effect of 27 percent higher production volume during 2019. The volume-based absolute increases were primarily attributable to compression and gas lift, water disposal, utilities and environmental costs for a combined effect of $5.6 million. Higher maintenance costs of $1.3 million were incurred in 2019. In addition, the 2019 period includes the effects of two additional months of production attributable to the Hunt Acquisition.

2018 vs. 2017. LOE increased on an absolute basis, but declined on a per unit basis during 2018 when compared to 2017. The absolute increases were due primarily to higher production volume including the incremental effects of the Devon and Hunt Acquisitions. The higher production volume also had the effect of decreasing the overall per unit cost, particularly those costs that have a higher fixed cost component. Furthermore, comprehensive maintenance costs in the second half of 2017 improved production and cost efficiency progressing throughout 2018.

Gathering Processing and Transportation

GPT expense includes costs that we incur to gather and aggregate our crude oil, NGL and natural gas production from our wells and deliver them via pipeline or truck to a central delivery point, downstream pipelines or processing plants, and blend or process, as necessary, depending upon the type of production and the specific contractual arrangements that we have with the applicable midstream operators.

The following table sets forth our GPT for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Gathering, processing and transportation	$ 23,197	$ 18,626	$ 10,734
Per unit of production ($/BOE)	$ 2.29	$ 2.34	$ 2.84

2019 vs. 2018. GPT expense increased on an absolute basis during 2019 when compared to 2018 due primarily to substantially higher production volumes as discussed above. Per unit costs declined marginally in 2019 compared to 2018 due primarily to a shift in the mix of crude oil production sold at the wellhead with no corresponding GPT expense subsequent to the achievement of required minimum crude oil volumes transported by pipeline partially offset by a scheduled rate increase effective August 1, 2019, for crude oil gathering services provided by Nuevo Dos Gathering & Transportation, LLC, or Nuevo G&T, successor to Republic Midstream, LLC.

2018 vs. 2017. GPT expense increased on an absolute basis during 2018 when compared to 2017 due primarily to substantially higher production volumes partially offset by the effect of the adoption of ASC Topic 606, or $2.4 million. Per unit costs declined $0.30 per BOE in 2018 due primarily to the effect of the adoption of ASC Topic 606, as well as a result of increased production sold at the wellhead with no corresponding GPT expense.

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 assessed value of our operating properties. The assessments for ad valorem taxes are generally based on contemporary commodity prices.

The following table sets forth our production and ad valorem taxes for the periods presented:

	Year Ended December 31,		
	2019	**2018**	**2017**
Production and ad valorem taxes			
Production/severance taxes	$ 21,774	$ 20,619	$ 7,533
Ad valorem taxes	6,283	2,928	1,281
	$ 28,057	$ 23,547	$ 8,814
Per unit of production ($/BOE)	$ 2.77	$ 2.96	$ 2.33
Production/severance tax rate as a percent of product revenues	4.6%	4.7%	4.7%

2019 vs. 2018. Production taxes increased on an absolute basis, but declined on a per unit basis during 2019 when compared to 2018 due primarily to increased production volume despite lower overall commodity sales prices. Accruals for ad valorem taxes also increased substantially for the 2019 periods due to a higher commodity-price based valuation assumption and the effects of growing our assessable property base and increased working interests from acquisition activity.

2018 vs. 2017. Production taxes increased on both an absolute and per unit basis during 2018 when compared to 2017 due primarily to increased production volume and higher commodity prices. Accruals for ad valorem taxes have also increased for 2018 as we have grown our assessable property base and we anticipate higher assessments as a result of higher commodity prices and increased working interests.

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A expenses, we have disaggregated certain costs into three components as presented in the table below. Primary G&A encompasses all G&A costs except share-based compensation and certain significant special charges that are generally attributable to material stand-alone transactions or corporate actions that are not otherwise in the normal course.

The following table sets forth the components of G&A expenses for the periods presented:

	Year Ended December 31,		
	2019	**2018**	**2017**
Primary G&A	$ 20,602	$ 17,236	$ 13,072
Share-based compensation - equity-classified	4,082	4,618	3,809
Significant special charges			
Acquisition, divestiture and strategic transaction costs	800	3,960	1,340
Executive retirement costs	—	250	—
Restructuring expense adjustment	—	—	(20)
Total general and administrative expenses	$ 25,484	$ 26,064	$ 18,201
Per unit of production ($/BOE)	$ 2.52	$ 3.28	$ 4.82
Per unit of production excluding all share-based compensation and other significant special charges identified above ($/BOE)	$ 2.04	$ 2.17	$ 3.46

2019 vs. 2018. Our primary G&A expenses increased on an absolute basis and decreased on a per unit basis during 2019 compared to 2018. The absolute increases are due primarily to the effects of higher payroll, benefits and support costs attributable to a higher overall employee headcount. In addition, we incurred higher occupancy costs and higher consulting and related costs including those associated with the SVP/CFO transition in the second half of 2019. Higher production volume had the effect of reducing G&A per unit of production during 2019.

Equity-classified share-based compensation charges during the periods presented are attributable to the amortization of compensation cost associated with the grants of time-vested restricted stock units, or RSUs, and performance restricted stock units, or PRSUs. The grants of RSUs and PRSUs are described in greater detail in Note 16 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." A substantial portion of the share-based compensation expense is attributable to the RSU and PRSU grants made in the normal course in January 2017 and RSU grants in September and December of 2016 in connection with our reorganization. The remainder is attributable to grants of RSUs and PRSUs to certain employees upon their hiring or as a result of promotion subsequent to the first quarter of 2017. The year 2018 also includes a charge of $0.6 million attributable to the accelerated vesting of certain RSUs and PRSUs in connection with the retirement of our Executive Chairman in February 2018. All of our equity-classified share-based compensation represents non-cash expenses.

We incurred consulting and other costs in the second half of 2018 which continued into the first quarter of 2019 associated with the previously terminated merger transaction. In addition to these costs, we incurred transaction costs in 2018 associated with the Mid-Continent divestiture and the Hunt Acquisition, including legal, due diligence and other professional fees. We also paid certain costs attributable to the retirement of our former Executive Chairman in February 2018.

2018 vs. 2017. Our primary G&A expenses increased on an absolute and decreased on a per unit basis during 2018 compared to 2017. The absolute increase is due primarily to the effects of higher payroll, benefits and support costs attributable to a higher overall employee headcount as well as costs associated with the relocation of our corporate headquarters to a new office within Houston, Texas. Higher production volume had the effect of reducing G&A per unit of production for 2018.

During 2017, we incurred transaction costs associated with the Devon Acquisition and certain costs in advance of the Hunt Acquisitions, including advisory, legal, due diligence and other professional fees. In 2017, we recorded adjustments to severance-related restructuring accruals that were originally established prior to 2017.

Depreciation, Depletion and Amortization (DD&A)

DD&A expense includes charges for the allocation of property costs based on the volume of production, depreciation of fixed assets other than oil and gas assets as well as the accretion of our ARO liabilities. The following table sets forth total and per unit costs for DD&A for the periods presented:

	Year Ended December 31,		
	2019	**2018**	**2017**
DD&A expense	$ 174,569	$ 127,961	$ 48,649
DD&A rate ($/BOE)	$ 17.25	$ 16.11	$ 12.87

2019 vs. 2018. DD&A increased on an absolute and per unit basis during 2019 when compared to 2018. Higher production volume provided for an increase of approximately $35.1 million while $11.5 million was attributable to the higher DD&A rates in 2019. The higher DD&A rates in 2019 are attributable to higher costs added to the full cost pool in 2019.

2018 vs. 2017. DD&A increased on an absolute and per unit basis during 2018 when compared to 2017. Higher production volume provided for an increase of approximately $53.6 million while $25.7 million was attributable to the higher DD&A rates in 2018. The higher DD&A rates in the 2018 periods were attributable to costs added to the full cost pool, including those from the Devon and Hunt Acquisitions, during a period of rising crude oil prices, as well as the sale of our Mid-Continent properties in July 2018, while the DD&A rate for 2017 period is based primarily on the fair value of our properties at September 2016.

Interest Expense

Interest expense includes charges for outstanding borrowings under the Credit Facility and the Second Lien Facility derived from internationally-recognized interest rates with a premium based on our credit profile and the level of credit outstanding. In addition, we are assessed certain fees for the overall credit commitments provided to us as well as fees for utilization and letters of credit. Also included is the accretion of original issue discount on the Second Lien Facility and the amortization of costs capitalized attributable to the Credit Facility and the Second Lien Facility. These costs are partially offset by interest costs that we capitalize on unproved property costs while we are engaged in the evaluation of projects for the underlying acreage.

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

	Year Ended December 31,		
	2019	2018	2017
Interest on borrowings and related fees	$ 36,593	32,164	$ 6,995
Accretion of original issue discount	743	680	161
Amortization of debt issuance costs	2,611	2,736	1,961
Capitalized interest	(4,136)	(9,118)	(2,725)
	$ 35,811	$ 26,462	$ 6,392

2019 vs. 2018. Interest expense increased during 2019 as compared to 2018 due primarily to higher outstanding balances under the Credit Facility partially offset by the effect of lower interest rates. Weighted-average balances under the Credit Facility were higher in 2019 compared to 2018 by approximately $119 million while the weighted-average interest rates were lower during the same period by 97 basis points. The accretion of original issue discount is entirely attributable to the Second Lien Facility and the amortization of debt issuance costs includes amounts attributable to both the Credit Facility and Second Lien Facility. We capitalized a smaller portion of interest during 2019 as we maintained a substantially smaller portion of unproved property as compared to 2018.

2018 vs. 2017. Interest expense increased during 2018 as compared to 2017 due primarily to higher outstanding balances under the Credit Facility, including amounts borrowed to fund our larger capital expenditure program in 2018 and the Hunt Acquisition, as well as interest attributable to the Second Lien Facility that was entered into in September 2017. Furthermore, the Credit Facility and the Second Lien Facility are variable-rate instruments and both were subject to periodic increases in LIBOR rates on a consistent basis since 2017. We capitalized a larger portion of interest during 2018 as we maintained a substantially larger balance of unproved property as compared to 2017 due primarily to the Devon Acquisition.

Derivatives

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.

The following table summarizes the gains and (losses) attributable to our crude oil derivatives portfolio for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Crude oil derivative gains (losses)	$ (68,131)	$ 37,427	$ (17,819)

2019 vs. 2018. In 2019, the forward curve for commodity prices increased relative to our weighted-average hedged prices resulting in net losses for our derivative portfolio. We paid net cash settlements of $4.1 million and $48.3 million in 2019 and 2018, respectively.

2018 vs. 2017. The forward curve for commodity prices declined relative to our weighted-average hedged prices during 2018 resulting in a net gain for the year ended December 31, 2018 while the forward curve for such prices increased relative to our weighted-average hedged prices during 2017. We paid cash settlements of $48.3 million in 2018 as compared to cash settlements paid of $3.5 million in 2017.

Other, Net

Other, net includes interest income, non-service costs associated with our retiree benefit plans and miscellaneous items of income and expense that are not directly associated with our current operations, including certain recoveries and write-offs attributable to prior years and properties that have been divested.

The following table sets forth the other income (expense), net recognized for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Other, net	$ (153)	$ 2,266	$ 58

2019. Other, net income (expense) decreased during 2019 as compared to 2018 due primarily to the write-off in 2019 of $0.2 million attributable to acquisition transactions in prior years that were no longer deemed recoverable. This charge was partially offset in 2019 by recoveries of sales and use taxes attributable to previously divested properties.

2018. In 2018, we received a recovery of $1.5 million from partners attributable to a prior-year acquisition and received recoveries of $0.3 million of joint interest receivable balances previously written-off in connection with the bankruptcy of a former partner. We also received severance tax refunds attributable to previously-divested properties in excess of recorded amounts, interest income earned on the escrow account attributable to the Devon Acquisition prior to the escrow account's liquidation in March 2018 as well as recording the reversal of a litigation reserve attributable to previously-divested properties. The combined benefit to income from these items was approximately $0.7 million. These amounts were partially offset by interest charges applicable to a settlement with a royalty owner and charges associated with our retiree benefit plans.

2017. In 2017, we recorded interest income attributable to the escrow account attributable to the Devon Acquisition that was partially offset by charges associated with our retiree benefit plans and certain costs attributable to assets that were sold in prior years.

Reorganization Items, Net

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Legal and professional fees and expenses	$ —	$ 200	$ —
Other reorganization items	—	3,122	—
	$ —	$ 3,322	$ —

2018. While we emerged from bankruptcy in September 2016, certain administrative and claims resolution activities continued until November 2018 when the Bankruptcy Court issued a final decree which effectively closed the case. Upon the closure, we reversed the remaining $0.2 million unused portion of an accrual that was established upon emergence from bankruptcy for legal and professional fees and administrative costs. In addition, we reversed the $2.7 million unallocated portion of a reserve that was established upon emergence for the potential settlement of certain claims in cash. Finally, we also reversed $0.4 million of accounts payable that were held open since the date of emergence as secured claims, but were ultimately expunged. As these items of income are directly attributable to the final administration of our bankruptcy case and not a part of our continuing operations, they are classified on our Consolidated Statement of Operations as components of "Reorganization items, net."

Income Taxes

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Income tax (expense) benefit	$ (2,137)	$ (523)	$ 4,943
Effective tax rate	3.0 %	0.2 %	17.8 %

2019. The provision for the year ended December 31, 2019 includes current federal benefits of $1.2 million attributable to the anticipated refund of alternative minimum tax, or AMT, credits for the 2019 tax year. The amount for 2019 has been recognized on our Consolidated Balance Sheet as of December 31, 2019 as a current asset. These benefits have been offset by corresponding decreases in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expense for the year ended December 31, 2019. In addition, we have recognized a deferred state tax expense of $2.1 million attributable to property and equipment for an overall effective tax rate of 3.0%.

2018. The provision for the year ended December 31, 2018 includes a current federal benefit of $2.5 million attributable to the anticipated refund of AMT credits for the 2018 tax year. The $2.5 million attributable to 2018 was refunded to us in 2019. This benefit is offset by a corresponding decrease in the deferred tax asset associated with the refundable AMT credit giving rise to a deferred federal expense. In addition, we have recognized a deferred state tax expense of $0.5 million for an overall effective tax rate of 0.2%.

2017. In connection with our analysis of the impact of the TCJA we recorded an income tax charge of $86.6 million for the year ended December 31, 2017, which consists of a reduction of deferred tax assets previously valued at 35%. We recorded a corresponding decrease in our deferred tax asset valuation allowance representing an income tax benefit for the same amount. In addition to the aforementioned offsetting items with respect to the reduction in income tax rates, our income tax provision included federal income taxes of $9.7 million applied at the statutory rate of 35% for 2017 and an adjustment of $10.8 million attributable to reductions in certain tax attributes of property and other adjustments of $0.3 million applied in connection with the filing of our 2016 income tax returns. These expenses were effectively offset by benefits attributable to the reduction in our deferred tax asset valuation allowance of $24.3 million and state income tax benefits of $1.4 million resulting in a net tax deferred benefit of $4.9 million, all of which is attributable to refundable AMT credit carryforwards.

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, 2019, the material off-balance sheet arrangements and transactions that we have entered into included information technology licensing, service agreements and letters of credit, all of which are customary in our business. See "*Contractual Obligations*" summarized below and Note 14 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data" 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, 2019:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Credit Facility [1]	$ 362,400	$ —	$ —	$ 362,400	$ —
Second Lien Facility [2]	200,000	—	—	200,000	—
Interest payments on long-term debt [3]	107,405	31,209	57,879	18,317	—
Operating leases [4]	3,483	847	1,664	972	—
Crude oil gathering and transportation commitments [5]	102,598	12,962	25,924	25,924	37,788
Asset retirement obligations [6]	113,050	—	—	—	113,050
Derivatives	20,488	19,853	635	—	—
Other commitments [7]	499	289	210	—	—
Total contractual obligations	$ 909,923	$ 65,160	$ 86,312	$ 607,613	$ 150,838

[1] Assumes that the amount outstanding of $362 million as of December 31, 2019 will remain outstanding until its maturity in 2024. 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 9 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[2] Assumes that the amount outstanding of $200 million as of December 31, 2019 will remain outstanding until its maturity in 2022. The Second Lien Facility has been classified as a long term liability on our Consolidated Balance Sheet as described in "Financial Condition – Liquidity" and in Note 9 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[3] Represents estimated interest payments that will be due under the Credit Facility and Second Lien Facility, assuming that the underlying LIBOR-based interest rates in effect at December 31, 2019 remain in effect and the amounts outstanding of $362.4 million and $200 million as of December 31, 2019, respectively, will remain outstanding until their maturities in 2024 and 2022, respectively.

[4] Relates primarily to office facilities and equipment leases as described in Note 11 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

[5] 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 Midstream.

[6] Represents the undiscounted balance payable, primarily for the plugging of inactive wells, in periods more than five years in the future for which $4.9 million, on a discounted basis, has been recognized on our Consolidated Balance Sheet as of December 31, 2019 and illustrated in Note 8 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data." While we may make payments to settle certain AROs, including those subject to regulatory requirements during each of the next five years, no material amounts are currently required by contract or regulatory authority to be made during this time frame.

[7] Represents all other significant obligations including information technology licensing and service agreements, among others as described in Note 14 to the Consolidated Financial Statements included in Part II, Item 8, "Financial Statements and Supplementary Data."

Critical Accounting Estimates

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

Oil and Gas Reserves

Estimates of our oil and gas reserves are the most critical estimate included in our Consolidated Financial Statements. Reserve estimates become the basis for determining depletive write-off rates 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

We apply 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. Factors we consider in our assessment include drilling results, the terms of oil and gas leases not held by production and drilling and completion capital expenditures consistent with our plans.

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. As of December 31, 2019, the carrying value of our proved oil and gas properties was below the limit determined by the Ceiling Test by approximately $480 million.

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.

Leases

Implicit in the recognition and measurement of our lease obligations and the related right-of-use, or ROU, assets are certain assumptions regarding discount rates, renewal options, cost escalations and other factors. Depending upon the length of term, including extensions if applicable, the magnitude of certain contractual costs and the applicable discount rate, certain of these critical assumptions could have a material impact on the underlying measurement.

Derivative Activities

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

Deferred Tax Asset Valuation Allowance

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized after consideration of future taxable income and reasonable tax planning strategies. In the event that we were to determine that we would not be able to realize all or a part of our deferred tax assets for which a valuation allowance had not been established, an adjustment to the deferred tax asset will be reflected in income in the period such determination is made. The most significant matter applicable to the realization of our deferred tax assets is attributable to net operating losses 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, 2019, we had a full valuation allowance for all of our deferred tax assets, with the exception of our remaining refundable AMT credit carryforwards, 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 FASB issued 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. 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 reasonably 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 which have a higher credit risk than those associated with our traditional customer receivables. We will adopt ASU 2016–13 effective January 1, 2020. While we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures, we will be applying new procedures and controls to our customer and partner billing processes in order to apply the expected loss model on a monthly basis.

Item 7A Quantitative and Qualitative Disclosures About Market Risk

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

Interest Rate Risk

Our interest rate risk is attributable to our borrowings under the Credit Facility and the Second Lien Facility, which are subject to variable interest rates. As of December 31, 2019, we had borrowings of $362.4 million under the Credit Facility at an interest rate of 3.75%. As of December 31, 2019, we had borrowings of $192.6 million under the Second Lien Facility, net of OID and issuance costs, at an interest rate of 8.81%. Assuming a constant borrowing level under the Credit and Second Lien Facilities, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in interest expense of approximately $5.6 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars and swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of oil and natural gas. As of December 31, 2019, we were not utilizing any derivative instruments with respect to NGLs and natural gas, although we may do so in the future.

As of December 31, 2019, we reported net commodity derivative liabilities of $20.0 million. The contracts associated with this position are with nine 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.

During the year ended December 31, 2019, we reported net commodity derivative losses of $68.1 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 6 to our Consolidated Financial Statements included in Part II, Item 8, included in Part II, Item 8, “Financial Statements and Supplementary Data” for a further description of our price risk management activities.

The following table sets forth our commodity derivative positions as ofDecember 31, 2019:

	1Q2020	2Q2020	3Q2020	4Q2020	1Q2021	2Q2021	3Q2021	4Q2021
NYMEX WTI Crude Swaps								
Average Volume Per Day (barrels)	15,648	12,648	10,630	10,630	3,333	3,297	1,630	1,630
Weighted Average Swap Price ($/barrel)	$ 55.34	$ 54.96	$ 54.77	$ 54.77	$ 55.89	$ 55.89	$ 55.50	$ 55.50
NYMEX WTI Purchased Puts/Sold Calls								
Average Volume Per Day (barrels)		3,297	4,891		1,667	1,648		
Weighted Average Purchased Put Price ($/barrel)		$ 55.00	$ 55.00		$ 55.00	$ 55.00		
Weighted Average Sold Call ($/barrel)		$ 57.69	$ 58.42		$ 58.00	$ 58.00		
NYMEX WTI Sold Puts								
Average Volume Per Day (barrels)					5,000	4,945	1,630	1,630
Weighted Average Sold Put Price ($/barrel)					$ 44.00	$ 44.00	$ 44.00	$ 44.00
MEH Crude Swaps								
Average Volume Per Day (barrels)	2,000	2,000	2,000	2,000				
Weighted Average Swap Price ($/barrel)	$ 61.03	$ 61.03	$ 61.03	$ 61.03				

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

	Change of $10.00 per Barrel of Crude Oil ($ in millions)	
	Increase	**Decrease**
Effect on the fair value of crude oil derivatives [1]	$ (69.8)	$ 66.6
Effect on 2020 operating income, excluding crude oil derivatives [2]	$ 29.0	$ (27.0)

[1] Based on derivatives outstanding as of December 31, 2019.

[2] Based on our 2020 Business Plan consistent with the assumptions used to determine our proved reserves as disclosed in Item 2, "Properties – *Summary of Oil and Gas Reserves* ." These sensitivities are subject to significant change

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

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Penn Virginia Corporation (a Virginia corporation) and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of itsoperations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 28, 2020 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas
February 28, 2020

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Penn Virginia Corporation

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Penn Virginia Corporation (a Virginia corporation) and subsidiaries (the "Company") as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2019, and our report dated February 28, 2020 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Houston, Texas
February 28, 2020

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Revenues			
Crude oil	$ 434,713	$ 402,485	$ 140,886
Natural gas liquids	16,589	21,073	10,066
Natural gas	17,733	15,972	8,517
Gain (loss) on sales of assets, net	5	(177)	(36)
Other revenues, net	2,176	1,479	621
Total revenues	471,216	440,832	160,054
Operating expenses			
Lease operating	43,088	35,879	21,784
Gathering, processing and transportation	23,197	18,626	10,734
Production and ad valorem taxes	28,057	23,547	8,814
General and administrative	25,484	26,064	18,201
Depreciation, depletion and amortization	174,569	127,961	48,649
Total operating expenses	294,395	232,077	108,182
Operating income	176,821	208,755	51,872
Other income (expense)			
Interest expense, net of amounts capitalized	(35,811)	(26,462)	(6,392)
Derivatives	(68,131)	37,427	(17,819)
Other, net	(153)	2,266	58
Reorganization items, net	—	3,322	—
Income before income taxes	72,726	225,308	27,719
Income tax (expense) benefit	(2,137)	(523)	4,943
Net income	$ 70,589	$ 224,785	$ 32,662
Net income per share:			
Basic	$ 4.67	$ 14.93	$ 2.18
Diluted	$ 4.67	$ 14.70	$ 2.17
Weighted average shares outstanding – basic	15,110	15,059	14,996
Weighted average shares outstanding – diluted	15,126	15,292	15,063

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Net income	$ 70,589	$ 224,785	$ 32,662
Other comprehensive income (loss):			
Change in pension and postretirement obligations, net of tax	(141)	82	(73)
	(141)	82	(73)
Comprehensive income	$ 70,448	$ 224,867	$ 32,589

See accompanying notes to consolidated financial statements.

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

	December 31, 2019	December 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$ 7,798	$ 17,864
Accounts receivable, net of allowance for doubtful accounts	70,716	66,038
Derivative assets	4,131	34,932
Income taxes receivable	1,236	2,471
Other current assets	4,458	5,125
Total current assets	88,339	126,430
Property and equipment, net (full cost method)	1,120,425	927,994
Derivative assets	2,750	10,100
Deferred income taxes	—	1,949
Other assets	6,724	2,481
Total assets	$ 1,218,238	$ 1,068,954
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 105,824	$ 103,700
Derivative liabilities	23,450	991
Total current liabilities	129,274	104,691
Other liabilities	8,382	5,533
Deferred income taxes	1,424	—
Derivative liabilities	3,385	—
Long-term debt, net	555,028	511,375
Commitments and contingencies (Note 14)		
Shareholders' equity:		
Preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued	—	—
Common stock of $0.01 par value – 45,000,000 shares authorized; 15,135,598 and 15,080,594 shares issued as of December 31, 2019 and December 31, 2018, respectively	151	151
Paid-in capital	200,666	197,630
Retained earnings	319,987	249,492
Accumulated other comprehensive income (loss)	(59)	82
Total shareholders' equity	520,745	447,355
Total liabilities and shareholders' equity	$ 1,218,238	$ 1,068,954

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2019	**2018**	**2017**
Cash flows from operating activities			
Net income	$ 70,589	$ 224,785	$ 32,662
Adjustments to reconcile net income to net cash provided by operating activities:			
Non-cash reorganization items	—	(3,322)	—
Depreciation, depletion and amortization	174,569	127,961	48,649
Derivative contracts:			
Net (gains) losses	68,131	(37,427)	17,819
Cash settlements, net	(4,136)	(48,291)	(3,511)
Deferred income tax expense (benefit)	3,373	2,994	(4,943)
Loss (gain) on sales of assets, net	(5)	177	36
Non-cash interest expense	3,354	3,416	2,122
Share-based compensation (equity-classified)	4,082	4,618	3,809
Other, net	52	44	61
Changes in operating assets and liabilities:			
Accounts receivable, net	(5,079)	(23,674)	(43,318)
Accounts payable and accrued expenses	4,690	21,109	28,542
Other assets and liabilities	574	(258)	(218)
Net cash provided by operating activities	320,194	272,132	81,710
Cash flows from investing activities			
Acquisitions, net	(6,516)	(85,387)	(200,849)
Capital expenditures	(362,743)	(430,592)	(115,687)
Proceeds from sales of assets, net	215	7,683	869
Net cash used in investing activities	(369,044)	(508,296)	(315,667)
Cash flows from financing activities			
Proceeds from credit facility borrowings	76,400	244,000	59,000
Repayment of credit facility borrowings	(35,000)	—	(7,000)
Proceeds from second lien note	—	—	196,000
Debt issuance costs paid	(2,616)	(989)	(9,787)
Proceeds received from rights offering, net	—	—	55
Other, net	—	—	(55)
Net cash provided by financing activities	38,784	243,011	238,213
Net increase (decrease) in cash and cash equivalents	(10,066)	6,847	4,256
Cash and cash equivalents - beginning of period	17,864	11,017	6,761
Cash and cash equivalents - end of period	$ 7,798	$ 17,864	$ 11,017
Supplemental disclosures:			
Cash paid for:			
Interest, net of amounts capitalized	$ 32,398	$ 22,599	$ 4,102
Income taxes, net of (refunds)	$ (2,471)	$ —	$ —
Reorganization items, net	$ 79	$ 540	$ 954
Non-cash investing and financing activities:			
Changes in accounts receivable, net related to acquisitions	$ (152)	$ (27,107)	$ (2,583)
Changes in other assets related to acquisitions	$ —	$ (743)	$ 3,201
Changes in accrued liabilities related to acquisitions	$ (540)	$ (11,182)	$ (2,507)
Changes in accrued liabilities related to capital expenditures	$ (3,602)	$ 44	$ 19,910
Changes in other liabilities for asset retirement obligations related to acquisitions	$ 83	$ 385	$ 494

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)	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
December 31, 2016	14,992	$ —	$ 150	$ 190,621	$ (5,296)	$ 73	$ 185,548
Net Income	—	—	—	—	32,662	—	32,662
Share-based compensation	—	—	—	3,809	—	—	3,809
Restricted stock unit vesting	27	—	—	(351)	—	—	(351)
All other changes	—	—	—	44	—	(73)	(29)
December 31, 2017	15,019	—	150	194,123	27,366	—	221,639
Net Income	—	—	—	—	224,785	—	224,785
Share-based compensation	—	—	—	4,618	—	—	4,618
Restricted stock unit vesting	61	—	1	(1,111)	—	—	(1,110)
Cumulative effect of change in accounting principle (see Note 5)	—	—	—	—	(2,659)	—	(2,659)
All other changes	—	—	—	—	—	82	82
December 31, 2018	15,080	—	151	197,630	249,492	$ 82	447,355
Net Income	—	—	—	—	70,589	—	70,589
Share-based compensation	—	—	—	4,082	—	—	4,082
Restricted stock unit vesting	56	—	—	(1,046)	—	—	(1,046)
Cumulative effect of change in accounting principle (see Note 11)	—	—	—	—	(94)	—	(94)
All other changes	—	—	—	—	—	(141)	(141)
December 31, 2019	15,136	$ —	$ 151	$ 200,666	$ 319,987	$ (59)	$ 520,745

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 of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in Gonzales, Lavaca, Fayette and DeWitt Counties in South Texas.

2. Basis of Presentation

Adoption of Recently Issued Accounting Pronouncements and Comparability to Prior Periods

Effective January 1, 2019, we adopted and began applying the relevant guidance provided in the Financial Accounting Standards Board's ("FASB") Accounting Standards Update ("ASU") 2016–02, *Leases* ("ASU 2016–02") and related amendments to accounting principles generally accepted in the United States of America ("GAAP") which, together with ASU 2016–02, represent Accounting Standards Codification ("ASC") Topic 842, *Leases* ("ASC Topic 842"). We adopted ASC Topic 842 using the optional transition approach with a charge to the beginning balance of retained earnings as of January 1, 2019 (see Note 11 for the impact and disclosures associated with the adoption of ASC Topic 842).

Effective January 1, 2018, we adopted and began applying the relevant guidance provided in ASU 2014–09,*Revenues from Contracts with Customers* ("ASU 2014–09") and related amendments to GAAP which, together with ASU 2014–09, represent ASC Topic 606, *Revenues from Contracts with Customers* ("ASC Topic 606"). We adopted ASC Topic 606 using the cumulative effect transition method (see Note 5 for the impact and disclosures associated with the adoption of ASC Topic 606).

Comparative periods and related disclosures have not been restated for the application of ASC Topic 842 and ASC Topic 606. Accordingly, certain components of our Consolidated Financial Statements are not comparable between periods and the Consolidated Statement of Operations for the year ended December 31, 2017 is presented based on prior GAAP for both revenue recognition and leases in their entirety.

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 which have a higher credit risk than those associated with our traditional customer receivables. We will adopt ASU 2016–13 effective January 1, 2020. While we do not anticipate that the adoption of ASU 2016–13 will have a significant impact on our Consolidated Financial Statements and related disclosures, we will be applying new procedures and controls to our customer and partner billing processes in order to apply the expected loss model on a monthly basis.

Going Concern Presumption

Our Consolidated Financial Statements 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, other than the entry into additional commodity derivative contracts including crude oil and natural gas hedges and certain interest rate swap agreements (see Note 6), all in the ordinary course of business, no subsequent events have occurred that would require recognition in our Consolidated Financial Statements or disclosure in the Notes thereto.

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 ofthree 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, generally take the form of collars and swaps. All derivative transactions are subject to our risk management policy, which has been reviewed and approved by our board of directors.

All derivative instruments are recognized in our Consolidated Financial Statements at fair value. The fair values of our derivative instruments are determined based on discounted cash flows derived from quoted forward prices. Our derivative instruments are not formally designated as hedges. We recognize changes in fair value in earnings currently as a component of the Derivatives caption 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 the underlying derivative contracts, which fluctuate with changes in commodity prices and interest rates.

Oil and Gas Properties

We apply the full cost method of accounting 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 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.

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.

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 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.

Leases

We determine if an arrangement is a lease at the inception of the underlying contractual arrangement. In addition, we determine whether the lease is classified as operating or financing. As of the date of adoption of ASC Topic 842 and through December 31, 2019, we do not have any financing leases. Leases are included in the captions "Other assets," "Accounts payable and accrued liabilities" and "Other liabilities" on our Consolidated Balance Sheets and are identified as Right-of-use ("ROU") assets, Current lease obligations and Noncurrent lease obligations, respectively, in Notes 11 and 12.

ROU assets represent our right to use an underlying asset for the lease term and lease obligations represent our obligation to make lease payments arising from the underlying contractual arrangement. Operating lease ROU assets and obligations are recognized at the commencement date based on the present value of lease payments over the lease term. The operating lease ROU assets include any lease payments made in advance and excludes lease incentives. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise such options. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term.

Most of our leasing arrangements do not identify or otherwise provide for an implicit interest rate. Accordingly, we utilize a secured incremental borrowing rate based on information available at the commencement date in the determination of the present value of the lease payments. As most of our lease arrangements have terms ranging from two to 5 years, our secured incremental borrowing rate is primarily based on the rates applicable to our credit agreement (the "Credit Facility").

We have lease arrangements that include lease and certain non-lease components, including amounts for related taxes, insurance, common area maintenance and similar terms. We have elected to apply a practical expedient provided in ASC Topic 842 to not separate the lease and non-lease components. Accordingly, the ROU assets and lease obligations for such leases will include the present value of the estimated payments for the non-lease components over the lease term.

Certain of our lease arrangements with contractual terms of 12 months or less are classified as short-term leases. Accordingly, we have elected to not include the underlying ROU assets and lease obligations on our Consolidated Balance Sheets. The associated costs are aggregated with all of our other lease arrangements and are disclosed in the tables in Note 11.

Certain of our lease arrangements result in variable lease payments which, in accordance with ASC Topic 842, do not give rise to lease obligations. Rather, the basis and terms and conditions upon which such variable lease payments are determined are disclosed in Note 11.

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 and Associated Costs

Crude oil. We sell our crude oil production to our customers at either the wellhead or a contractually agreed-upon delivery point, including certain regional central delivery point terminals or pipeline inter-connections. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality, location differentials and, if applicable, deductions for intermediate transportation. Costs incurred by us for gathering and transporting the products to an agreed-upon delivery point are recognized as a component of GPT expense.

NGLs. We have natural gas processing contracts in place with certain midstream processing vendors. We deliver “wet” natural gas to our midstream processing vendors at the inlet of their processing facilities through gathering lines, certain of which we own and others which are owned by gathering service providers. Subsequent to processing, NGLs are delivered or otherwise transported to a third-party customer. Depending upon the nature of the contractual arrangements with the midstream processing vendors, particularly those attributable to the marketing of the NGL products, we recognize revenue for NGL products on either a gross or net basis. For those contracts where we have determined that we are the principal, and the ultimate third party is our customer, we recognize revenue on a gross basis, with associated processing costs presented as GPT expenses. For those contracts where we have determined that we are the agent and the midstream processing vendor is our customer, we recognize NGL product revenues based on a net basis with processing costs presented as a reduction of revenue. Based on an analysis of all of our existing natural gas processing contracts, we have determined that, as of January 1, 2018, and through December 31, 2019, we were the agent and our midstream processing vendors were our customers with respect to all of our NGL product sales.

Natural gas. Subsequent to the aforementioned processing of “wet” natural gas and the separation of NGL products, the “dry” or residue gas is delivered to us at the tailgate of the midstream processing vendors’ facilities and we market the product to our customers, most of whom are interstate pipelines. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality and location differentials, as applicable. Costs incurred by us for gathering and transportation from the wellhead through the processing facilities are recognized as a component of GPT expenses.

Marketing services. We provide marketing services to certain of our joint venture partners and other third parties with respect to oil and gas production for which we are the operator. Pricing for such services represents a negotiated fixed rate fee based on the sales price of the underlying oil and gas products. Production attributable to joint venture partners from wells that we operate that are not subject to marketing agreements are delivered in kind. Marketing revenue is recognized simultaneously with the sale of our commodity production to our customers. Direct costs associated with our marketing efforts are included in G&A expenses.

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 equity-classified awards are generally amortized on a straight-line basis over the applicable vesting period except for those that are based on performance which are amortized on a graded basis over the term of the applicable performance periods. Compensation cost associated with 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. 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.

Reorganization Items

We emerged from bankruptcy in September 2016 and a final decree was issued in November 2018, at which time we recognized all final adjustments associated with the discharge action. These adjustments included certain gains and losses and are included in this caption on our Consolidated Statement of Operations as these items of income are directly attributable to the final administration of our bankruptcy case and not a part of our continuing operations.

4. Acquisitions and Divestitures

Acquisitions

Eagle Ford Working Interests

In 2019, we acquired working interests in certain properties for which we are the operator from our joint venture partners in a series of transactions for cash consideration of $6.5 million. Funding for these acquisition was provided by borrowings under the Credit Facility.

Hunt Acquisition

In December 2017, we entered into a purchase and sale agreement with Hunt Oil Company ("Hunt") to acquire certain oil and gas assets in the Eagle Ford Shale, covering approximately 9,700 net acres primarily in Gonzales County, Texas for $86.0 million in cash (the "Hunt Acquisition"). The Hunt Acquisition had an effective date of October 1, 2017 and closed in 2018. We paid total cash consideration of $83.0 million, net of suspended revenues received, for the Hunt Acquisition in 2018. We also acquired working interests in certain wells that we previously drilled as operator in which Hunt had rights to participate prior to the transaction closing. Accumulated costs, net of suspended revenues for these wells was $13.8 million, along with $0.2 million of certain working capital adjustments which we have reflected as components of the total net assets acquired. We funded the Hunt Acquisition with borrowings under the Credit Facility.

We incurred a total of $0.5 million of transaction costs for legal, due diligence and other professional fees associated with the Hunt Acquisition, including $0.1 million in 2017 and $0.4 million in 2018. These costs have been recognized as a component of our G&A expenses.

We accounted for the Hunt Acquisition by applying the acquisition method of accounting as of March 1, 2018. The following table represents the final fair values assigned to the net assets acquired and the total acquisition cost incurred, including consideration transferred to Hunt:

Assets		
Oil and gas properties - proved	$	82,443
Oil and gas properties - unproved		16,339
Liabilities		
Revenue suspense		1,448
Asset retirement obligations		356
Net assets acquired	$	96,978
Cash consideration paid to Hunt, net	$	82,955
Application of working capital adjustments		245
Accumulated costs, net of suspended revenues, for wells in which Hunt had rights to participate		13,778
Total acquisition costs incurred	$	96,978

Devon Acquisition

In July 2017, we entered into a purchase and sale agreement (the "Purchase Agreement"), with Devon Energy Corporation ("Devon") to acquire all of Devon's right, title and interest in and to certain oil and gas assets (the "Devon Properties"), including oil and gas leases covering approximately 19,600 net acres located primarily in Lavaca County, Texas for aggregate consideration of $205 million in cash (the "Devon Acquisition"). We also acquired working interests in the Devon Properties from parties that had tag-along rights to sell their interests under the Purchase Agreement. The Devon Acquisition had an effective date of March 1, 2017 and closed in September 2017. We paid total cash consideration of $199.8 million for the Devon Acquisition including $200.9 million paid in 2017 net of $1.1 million of suspended revenues and other adjustments paid to us in 2018 in connection with a final settlement. The Devon Acquisition was financed with the net proceeds received from borrowings under the $200 million Second Lien Credit Agreement dated as of September 29, 2017 (the "Second Lien Facility") (see Note 9 for terms of the Second Lien Facility) and incremental borrowings under the Credit Facility.

We incurred a total of $1.3 million of transaction costs associated with the Devon Acquisitions during 2017, including advisory, legal, due diligence and other professional fees. These costs have been recognized as a component of our G&A expenses.

We accounted for the Devon Acquisition by applying the acquisition method of accounting as of September 29, 2017. The following table represents the final fair values assigned to the net assets acquired and the total consideration transferred:

Assets		
Oil and gas properties - proved	$	42,866
Oil and gas properties - unproved		146,686
Other property and equipment		8,642
Liabilities		
Revenue suspense		355
Asset retirement obligations		494
Net assets acquired	$	197,345
Cash consideration paid to Devon and tag-along parties, net	$	199,796
Application of working capital adjustments, net		(2,451)
Total consideration	$	197,345

Valuation of Acquisitions

The fair values of the oil and gas properties acquired in the Hunt and Devon Acquisitions were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future cash flows (v) the timing of or development plans and (vi) a market-based weighted-average cost of capital. The fair value of the other property and equipment acquired was measured primarily with reference to replacement costs for similar assets adjusted for the age and normal use of the underlying assets. Because many of these inputs are not observable, we have classified the initial fair value estimates as Level 3 inputs as that term is defined in GAAP.

Impact of Acquisitions on Actual and Pro Forma Results of Operations

The results of operations attributable to the Hunt and Devon Acquisitions have been included in our Consolidated Financial Statements for the periods after March 1, 2018 and September 30, 2017, respectively. The Devon Acquisition provided revenues and estimated earnings, excluding allocations of interest expense and income taxes, of approximately $9 million and $4 million, respectively, for the period from October 1, 2017 through December 31, 2017. The Hunt Acquisition provided revenues and estimated earnings, excluding allocations of interest expense and income taxes, of approximately $0.4 million and $0.2 million, respectively, for the period from March 1, 2018 through March 31, 2018. As the properties and working interests acquired in connection with the Hunt and Devon Acquisitions are included within our existing Eagle Ford acreage, it is not practical or meaningful to disclose revenues and earnings unique to those assets for periods beyond those during which they were acquired, as they were fully integrated into our regional operations soon after their acquisition.

The following table presents unaudited summary pro forma financial information for the years ended December, 31, 2018 and 2017 assuming the Hunt and Devon Acquisitions and the related entry into the Second Lien Facility occurred as of January 1, 2017. The pro forma financial information does not purport to represent what our actual results of operations would have been if the Hunt and Devon Acquisitions and the entry into the Second Lien Facility had occurred as of this date, or the results of operations for any future periods.

	Year Ended December 31,			
	2018		2017	
Total revenues	$	446,077	$	209,015
Net income	$	227,930	$	30,861
Net income per share - basic	$	15.14	$	2.06
Net income per share - diluted	$	14.91	$	2.05

Divestitures

Mid-Continent Divestiture

In June 2018, we entered into a purchase and sale agreement with a third party to fully divest our Mid-Continent operations and sell all of our remaining oil and gas properties, located primarily in Oklahoma in the Granite Wash, for $6.0 million in cash, subject to customary adjustments. The sale had an effective date of March 1, 2018 and closed on July 31, 2018, and we received proceeds of $6.2 million. The sale proceeds and de-recognition of certain assets and liabilities were recorded as a reduction of our net oil and gas properties. In November 2018, we paid $0.5 million, including $0.2 million of suspended revenues, to the buyer in connection with the final settlement.

The Mid-Continent properties had AROs of $0.3 million as well as a net working capital deficit attributable to the oil and gas properties of $1.3 million as of July 31, 2018. The net pre-tax operating income attributable to the Mid-Continent assets was $1.6 million and $2.2 million for the years ended December 31, 2018 and December 31, 2017, respectively.

Sales of Undeveloped Acreage, Rights and Other Assets

In February 2018, we sold all of our undeveloped acreage holdings in the Tuscaloosa Marine Shale in Louisiana that were scheduled to expire in 2019. In March 2018, we sold certain undeveloped deep leasehold rights in our former Mid-Continent operating region in Oklahoma, and in May 2018, we sold certain pipeline assets in our former Marcellus Shale operating region. We received a combined total of $1.7 million for these leasehold and other assets which were applied as a reduction of our net oil and gas properties.

5. Accounts Receivable and Major Customers

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

	December 31,	
	2019	2018
Customers	$ 63,165	$ 59,030
Joint interest partners	6,929	6,404
Other	674	640
	70,768	66,074
Less: Allowance for doubtful accounts	(52)	(36)
	$ 70,716	$ 66,038

For the year ended December 31, 2019, four customers accounted for $354.6 million, or approximately 76% of our consolidated product revenues. The revenues generated from these customers during 2019 were $172.3 million, $84.6 million, $50.7 million and $47.0 million or 37%, 18%, 11% and 10% of the consolidated total, respectively. As of December 31, 2019, $44.5 million, or approximately 70% of our consolidated accounts receivable from customers was related to these customers. For the year ended December 31, 2018, three customers accounted for $304.3 million, or approximately 69% of our consolidated product revenues. The revenues generated from these customers during 2018 were $173.0 million, $71.5 million and $59.8 million, or approximately 39%, 16% and 14% of the consolidated total, respectively. As of December 31, 2018, $28.6 million, or approximately 48% 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. The allowance for doubtful accounts is entirely attributable to certain receivables from joint interest partners.

Revenue from Contracts with Customers

Adoption of ASC Topic 606

Effective January 1, 2018, we adopted ASC Topic 606 and have applied the guidance therein to our contracts with customers for the sale of commodity products (crude oil, NGLs and natural gas) as well as marketing services that we provide to our joint venture partners and other third parties. ASC Topic 606 provides for a five-step revenue recognition process model to determine the transfer of goods or services to consumers in an amount that reflects the consideration to which we expect to be entitled in exchange for such goods and services.

Upon the adoption of ASC Topic 606, we: (i) changed the presentation of our NGL product revenues from a gross basis to a net basis and changed the classification of certain natural gas processing costs associated with NGLs from a component of “Gathering, processing and transportation” (“GPT”) expense to a reduction of NGL product revenues as described in further detail below, (ii) wrote off $2.7 million of accounts receivable arising from natural gas imbalances accounted for under the entitlements method as a direct reduction to our beginning balance of retained earnings as of January 1, 2018, and (iii) adopted the sales method with respect to production imbalance transactions beginning after December 31, 2017.

Transaction Prices, Contract Balances and Performance Obligations

Substantially all of our commodity product sales are short-term in nature with contract terms of one year or less. Accordingly, we have applied the practical expedient included in ASC Topic 606, which provides for an exemption from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied as described above. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create contract assets or liabilities as those terms are defined in ASC Topic 606.

We record revenue in the month that our oil and gas production is delivered to our customers. 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. 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.

6. Derivative Instruments

We utilize derivative instruments, typically swaps, two- and three-way collars and enhanced swaps which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. Our derivative instruments are not formally designated as hedges in the context of GAAP. While the use of derivative instruments limits the risk of adverse commodity price and interest rate movements, such use may also limit future product revenues and interest expense from favorable price and rate movements. In addition, we do not utilize derivative instruments for speculative purposes. As of December 31, 2019, we were unhedged with respect to NGL and natural gas production and we had no interest rate hedges outstanding. The following is a general description of the derivative instruments we have employed:

Swaps. The counterparty to a swap contract is required to make a payment to us if the settlement price for any settlement period is below the 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 swap price for such contract.

Two-Way Collars. The counterparty to a two-way collar contract is required to make a payment to us if the settlement price for any settlement period is below the floor 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 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.

Three-Way Collars. A three-way collar consists of (i) a purchased put option which establishes a floor price for the collar, (ii) a sold call option which establishes a ceiling price of the collar and (iii) a sold put option which establishes a sub-floor price. Three-way collars are settled based on differences between the floor or ceiling prices and the settlement price of a referenced index or the difference between the floor price and sub-floor price. If the settlement price of the referenced index is below the sub-floor price, the counterparty is required to make a payment to us for the difference between the floor price and sub-floor price. If the settlement price of the referenced index is between the floor price and sub-floor price, the counterparty is required to make a payment to us for the difference between the floor price and the settlement price of the referenced index. If the settlement price of the referenced index is between the floor price and ceiling price, no payments are due to or from either party. If the settlement price of the referenced index is above the ceiling price, we are required to make a payment to the counterparty for the difference.

Enhanced Swaps. An enhanced swap consists of a sold put option with the associated premiums rolled into an enhanced fixed price swap. The counterparty to an enhanced swap contract is required to make a payment to us if the settlement price for any settlement period is below the 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 swap price for such contract. Additionally, we are required to make a payment to the counterparty if the settlement price for any settlement period is below the sold-put strike price. Effectively, when the settlement price for any settlement period is below the sold-put strike price, we receive the swap price minus the sold put strike price.

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 ("WTI"), Louisiana Light Sweet ("LLS") and Magellan East Houston ("MEH") 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.

Subsequent Events

In January of 2020, we entered into additional commodity hedge contracts as well as certain interest rate swap transactions. We replaced a portion of two crude oil swaps with a costless collar for 2,000 BOPD for April through December 2020 with floor and ceiling prices of $48.00 and $57.10 per barrel. We entered into a costless collar for Henry Hub natural gas for 270,000 MMBTU per month with a term from February through December of 2020 with floor and ceiling prices of $2.00 and $2.18 per MMBTU, respectively. In January and February 2020, we entered into interest rate swaps contracts through May 2022 for a notional amount of $300 million, paying a weighted-average fixed rate of 1.36%.

The following table sets forth our commodity derivative contracts as of December 31, 2019:

	1Q2020	2Q2020	3Q2020	4Q2020	1Q2021	2Q2021	3Q2021	4Q2021
NYMEX WTI Crude Swaps								
Average Volume Per Day (barrels)	15,648	12,648	10,630	10,630	3,333	3,297	1,630	1,630
Weighted Average Swap Price ($/barrel)	$ 55.34	$ 54.96	$ 54.77	$ 54.77	$ 55.89	$ 55.89	$ 55.50	$ 55.50
NYMEX WTI Purchased Puts/Sold Calls								
Average Volume Per Day (barrels)		3,297	4,891		1,667	1,648		
Weighted Average Purchased Put Price ($/barrel)		$ 55.00	$ 55.00		$ 55.00	$ 55.00		
Weighted Average Sold Call ($/barrel)		$ 57.69	$ 58.42		$ 58.00	$ 58.00		
NYMEX WTI Sold Puts								
Average Volume Per Day (barrels)					5,000	4,945	1,630	1,630
Weighted Average Sold Put Price ($/barrel)					$ 44.00	$ 44.00	$ 44.00	$ 44.00
MEH Crude Swaps								
Average Volume Per Day (barrels)	2,000	2,000	2,000	2,000				
Weighted Average Swap Price ($/barrel)	$ 61.03	$ 61.03	$ 61.03	$ 61.03				

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

The following table summarizes the effects of our derivative activities for the periods presented:

	Year Ended December 31,		
	2019	2018	2017
Derivative gains (losses) recognized in the Consolidated Statements of Operations	$ (68,131)	$ 37,427	$ (17,819)
Cash settlements recognized in the Consolidated Statements of Cash Flows	$ (4,136)	$ (48,291)	$ (3,511)

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

		Fair Values			
		December 31, 2019		December 31, 2018	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 4,131	$ 23,450	$ 34,932	$ 991
Commodity contracts	Derivative assets/liabilities – noncurrent	2,750	3,385	10,100	—
		$ 6,881	$ 26,835	$ 45,032	$ 991

As of December 31, 2019, we reported net commodity derivative liabilities of $20.0 million. The contracts associated with this position are with nine counterparties, all of which are investment grade financial institutions and are participants in the Credit Facility. 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.

7. Property and Equipment

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

	December 31,	
	2019	2018
Oil and gas properties:		
Proved	$ 1,409,219	$ 1,037,993
Unproved	53,200	63,484
Total oil and gas properties	1,462,419	1,101,477
Other property and equipment	25,915	20,383
Total property and equipment	1,488,334	1,121,860
Accumulated depreciation, depletion and amortization	(367,909)	(193,866)
	$ 1,120,425	$ 927,994

Unproved property costs of $53.2 million and $63.5 million have been excluded from amortization as of December 31, 2019 and December 31, 2018, respectively. An additional $0.3 million of costs, associated with wells in-progress for which we had not previously recognized any proved undeveloped reserves, were excluded from amortization as of December 31, 2018. The total costs not subject to amortization as of December 31, 2019 were incurred in the following periods: $1.3 million in 2019, $6.1 million in 2018, $43.1 million in 2017 and the remaining $2.7 million in 2016. We transferred $16.8 million and $82.8 million of undeveloped leasehold costs, including capitalized interest, associated with proved undeveloped reserves, acreage unlikely to be drilled or expiring acreage, from unproved properties to the full cost pool during the years ended December 31, 2019 and 2018, respectively. We capitalized internal costs of $4.1 million, $3.7 million and $2.4 million and interest of $4.1 million, $9.1 million and $2.7 million during the year ended December 31, 2019, 2018 and 2017 respectively, in accordance with our accounting policies. Average DD&A per barrel of oil equivalent of proved oil and gas properties was $17.25, $16.11 and $12.87 for the years ended December 31, 2019, 2018 and 2017, respectively.

8. 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:

	Year Ended December 31,	
	2019	2018
Balance at beginning of period	$ 4,314	$ 3,286
Changes in estimates	(2)	354
Liabilities incurred	290	335
Liabilities settled	(67)	(8)
Acquisitions of properties	83	385
Sale of properties	—	(310)
Accretion expense	316	272
Balance at end of period	$ 4,934	$ 4,314

9. Long-Term Debt

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

	December 31, 2019		December 31, 2018	
	Principal	Unamortized Discount and Issuance Costs [1]	Principal	Unamortized Discount and Issuance Costs [1]
Credit facility [2]	$ 362,400		$ 321,000	
Second lien term loan	200,000	$ 7,372	200,000	$ 9,625
Totals	562,400	7,372	521,000	9,625
Less: Unamortized discount	(2,415)		(3,159)	
Less: Unamortized deferred issuance costs	(4,957)		(6,466)	
Long-term debt, net	$ 555,028		$ 511,375	

[1] Discount and issuance costs of the Second Lien Facility are being amortized over the term of the underlying loan using the effective-interest method.

[2] Issuance costs of the Credit Facility, which represent costs attributable to the access to credit over its contractual term, have been presented as a component of Other assets (see Note 12) and are being amortized over the term of the Credit Facility using the straight-line method.

Credit Facility

The Credit Facility provides for a $1.0 billion revolving commitment and $500 million borrowing base including a $25 million sublimit for the issuance of letters of credit. In December 2019, we completed our fall borrowing base redetermination and our lenders affirmed the $500 million borrowing base. In the years ended December 31, 2019 and December 31, 2018, we paid and capitalized issue costs of $2.6 million and $0.9 million, respectively in connection with amendments to the Credit Facility. Availability under the Credit Facility may not exceed the lesser of the aggregate commitments or the borrowing base. The borrowing base under the Credit Facility is redetermined semi-annually, generally in April and October of each year. Additionally, 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 for general corporate purposes, including working capital. We had $0.4 million in letters of credit outstanding as of December 31, 2019 and December 31, 2018.

In May 2019, maturity of the Credit Facility was extended to May 2024 from September 2020; provided that on June 30, 2022, unless we have either extended the maturity date of the Second Lien Facility described below to a date that is at least 91 days after the May 7, 2024 or have repaid our Second Lien Facility in full, the maturity date of the Credit Facility will mean June 30, 2022.

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 0.50% to 1.50%, 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 1.50% to 2.50%, 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, 2019, the actual interest rate on the outstanding borrowings under the Credit Facility was 3.75%. Unused commitment fees are charged at a rate of 0.375% to 0.50%, depending upon utilization.

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. There are no significant restrictions on our ability 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 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 (2) a maximum leverage ratio (consolidated indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter, of 4.00 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), limitations on the incurrence of liens and indebtedness, merger, consolidation or sale of assets, payment of dividends, and transactions with affiliates and other customary covenants.

The Credit Facility contains customary events of default and remedies for credit facilities of this nature. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of December 31, 2019, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Credit Facility.

Second Lien Facility

On September 29, 2017, we entered into the Second Lien Facility. We received net proceeds of $187.8 million from the Second Lien Facility net of an original issue discount ("OID") of $4.0 million and issue costs of $8.2 million. The proceeds from the Second Lien Facility were used to fund the Devon Acquisition and related fees and expenses. The maturity date under the Second Lien Facility is September 29, 2022.

The outstanding borrowings under the Second Lien Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate based on the prime rate plus an applicable margin of 6.00% or (b) a customary LIBOR rate plus an applicable margin of 7.00%. As of December 31, 2019, the actual interest rate of outstanding borrowings under the Second Lien Facility was 8.81%. Amounts under the Second Lien Facility were borrowed at a price of 98% with an initial interest rate of 8.34% resulting in an effective interest rate of 9.89%. 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 or three months (including in three month intervals if we select a six-month interest period), at our election and is computed on the basis of a 360-day year. We have the right, to the extent permitted under the Credit Facility and an intercreditor agreement between the lenders under the Credit Facility and the lenders under the Second Lien Facility, to prepay loans under the Second Lien Facility at any time, subject to the following prepayment premiums (in addition to customary "breakage" costs with respect to eurocurrency loans): from October 2019 through September 2020, 101% of the amount being prepaid; and thereafter, no premium. The Second Lien Facility also provides for the following prepayment premiums in the event of a change in control that results in an offer of prepayment that is accepted by the lenders under the Second Lien Facility: from October 2019 through September 2020, 101% of the amount being prepaid; and thereafter, no premium.

The Second Lien Facility is collateralized by substantially all of the Company's and its subsidiaries' assets with lien priority subordinated to the liens securing the Credit Facility. The obligations under the Second Lien Facility are guaranteed by us and the Subsidiary Guarantors.

The Second Lien Facility has no financial covenants, but 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), limitations 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 illustrated in the table above, the OID and issue costs of the Second Lien Facility are presented as reductions to the outstanding term loan. These costs are subject to amortization using the interest method over the five-year term of the Second Lien Facility.

As of December 31, 2019, and through the date upon which the Consolidated Financial Statements were issued, we were in compliance with all of the covenants under the Second Lien Facility.

10. Income Taxes

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

	Year Ended December 31,		
	2019	2018	2017
Current income taxes (benefit)			
Federal	$ (1,236)	$ (2,471)	$ —
	(1,236)	(2,471)	—
Deferred income taxes (benefit)			
Federal	1,236	2,471	(4,943)
State	2,137	523	—
	3,373	2,994	(4,943)
	$ 2,137	$ 523	$ (4,943)

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

	Year Ended December 31,					
	2019		2018		2017	
Computed at federal statutory rate	$ 15,272	21.0 %	$ 47,315	21.0 %	$ 9,701	35.0 %
State income taxes, net of federal income tax benefit	1,494	2.1 %	1,743	0.8 %	(1,383)	(5.0)%
Change in valuation allowance	(14,240)	(19.6)%	(48,820)	(21.7)%	(24,353)	(87.8)%
Effect of rate change on the valuation allowance	—	— %	—	— %	(86,612)	(312.5)%
Effect of rate change	—	— %	—	— %	86,612	312.5 %
Reorganization adjustments	—	— %	—	— %	10,760	38.8 %
Other, net	(389)	(0.5)%	285	0.1 %	332	1.2 %
	$ 2,137	3.0 %	$ 523	0.2 %	$ (4,943)	(17.8)%

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

	December 31,	
	2019	2018
Deferred tax assets:		
Net operating loss (“NOL”) carryforwards	$ 175,221	$ 163,437
Alternative minimum tax (“AMT”) credit carryforwards	1,236	2,471
Asset retirement obligations	1,073	647
Pension and postretirement benefits	340	441
Share-based compensation	880	546
Fair value of derivative instruments	4,191	—
Interest expense limitation	11,463	3,128
Other	2,441	2,590
	196,845	173,260
Less: Valuation allowance	(114,939)	(128,650)
Total net deferred tax assets	81,906	44,610
Deferred tax liabilities:		
Property and equipment	83,330	33,413
Fair value of derivative instruments	—	9,248
Total deferred tax liabilities	83,330	42,661
Net deferred tax assets (liabilities)	$ (1,424)	$ 1,949

Continuing Impact of 2017 Tax Reform

In 2017, the U.S. Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (the "TCJA"). The TCJA provided for broad and complex changes to the U.S. tax code (the "Code"). In addition to the reduction in the U.S. federal corporate income tax rate from 35% to 21%, the most significant aspects of the TCJA that continue to have a material impact on us are those attributable to: (i) the repeal of the corporate AMT, (ii) limitations on deductible interest expense and (iii) the utilization and limitations on NOLs. The specific impact of these TCJA-related items are described in further detail below in our discussion of the income tax provision and our deferred tax assets and liabilities.

As a result of the repeal of the AMT, our existing AMT credit carryovers became refundable beginning with the 2018 tax year. The AMT credit carryforwards are used to offset current year regular tax liabilities with 50 percent of any excess remaining credit per year being refundable as part of the annual income tax filing.

Income Tax Provision

The provision for the years ended December 31, 2019 and 2018 includes current federal benefits of $1.2 million and $2.5 million attributable to the anticipated refund of AMT credits for the 2019 and 2018 tax years, respectively. The amount for 2019 has been recognized on our Consolidated Balance Sheet as of December 31, 2019 as a current asset. The $2.5 million attributable to 2018 was refunded to us in 2019. These benefits have been offset by corresponding decreases in the deferred tax asset associated with AMT credit carryforwards giving rise to deferred federal expenses for the years ended December 31, 2019 and 2018, respectively. In addition, we have a recognized deferred state tax expenses of $2.1 million and $0.5 million attributable to property and equipment for overall effective tax rates of 3.0% and 0.2% for the years ended December 31, 2019 and 2018, respectively. The remaining AMT credit carryforwards of approximately $1.2 million will be reclassified from deferred tax assets, where they are classified as of December 31, 2019, to income taxes receivable upon the filing of federal returns in future years.

In connection with the TCJA, we recorded an income tax charge of $86.6 million for the year ended December 31, 2017, which consisted of a reduction of deferred tax assets previously valued at 35%. We recorded a corresponding decrease in our deferred tax asset valuation allowance representing an income tax benefit for the same amount. In addition, our provision for the year ended December 31, 2017 included federal income taxes of $9.7 million applied at the statutory rate of 35% and an adjustment of $10.8 million attributable to reductions in certain tax attributes of property and other adjustments of $0.3 million applied in connection with the filing of our 2016 income tax returns. These expenses were effectively offset by benefits attributable to the reduction in our deferred tax asset valuation allowance of $24.4 million and state income tax benefits of $1.4 million resulting in a net tax deferred benefit of $4.9 million.

Deferred Tax Assets and Liabilities

As of December 31, 2019, we had federal NOL carryforwards of approximately $613.4 million, a substantial portion of which, if not utilized, expire between 2032 and 2037. NOLs incurred after January 1, 2018 can be carried forward indefinitely. State NOL carryforwards of approximately $437.9 million expire between 2024 and 2037. Because of the change in ownership provisions of the Code, use of a portion of our federal and state NOLs may be limited in future periods. As of December 31, 2019, we carried a valuation allowance against our federal and state deferred tax assets of $114.9 million. 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. The amount of deferred tax assets 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 is no longer present and additional weight is given to subjective positive evidence, including projections for growth.

The net deferred tax liability recognized on the Consolidated Balance Sheet as of December 31, 2019 is attributable to certain state deferred tax liabilities associated with property and equipment in excess of federal deferred tax assets associated with refundable AMT credit carryforwards for tax years ending after 2019. The net deferred tax asset recognized on the Consolidated Balance Sheet as of December 31, 2018 is attributable to federal deferred tax assets associated with AMT credit carryforwards in excess of certain state deferred tax liabilities attributable to property and equipment. The valuation allowance related to all other net deferred tax assets remains in full as of December 31, 2019 and 2018.

Other Income Tax Matters

We had no liability for unrecognized tax benefits as of December 31, 2019 and 2018. There were no interest and penalty charges recognized during the years ended December 31, 2019, 2018 and 2017. Tax years from 2015 forward remain open for examination by the Internal Revenue Service and various state jurisdictions.

11. Leases

Adoption of ASC Topic 842

Effective January 1, 2019, we adopted ASC Topic 842 and have applied the guidance therein to all of our contracts and agreements explicitly identified as leases as well as other contractual arrangements that we have determined to include or otherwise have the characteristics of a lease as defined in ASC Topic 842. As illustrated in the disclosures below, the adoption of ASC Topic 842 resulted in the recognition of certain assets and liabilities on our Consolidated Balance Sheet and changes in the amounts and timing of lease cost recognition in our Consolidated Statements of Operations as compared to prior GAAP. We have adopted ASC Topic 842 using the optional transition approach with an adjustment to the beginning balance of retained earnings as of January 1, 2019. Accordingly, our 2019 financial statements are not comparable with respect to leases in effect during all periods prior to January 1, 2019. On January 1, 2019, we recognized operating lease right-of-use ("ROU") assets of $2.5 million and operating lease obligations of $2.8 million on our Consolidated Balance Sheet for operating leases in effect on that date. We recorded an immaterial adjustment to the beginning balance of retained earnings as of January 1, 2019 representing the difference between the operating lease ROU assets and operating lease obligations recognized upon adoption net of amounts already included in our liabilities as of December 31, 2018 that were attributable to straight-line lease expense in excess of amounts paid for certain operating leases. We did not identify any finance leases, as defined in ASC Topic 842, upon the date of initial adoption.

Lease Arrangements and Supplemental Disclosures

We have lease arrangements for office facilities and certain office equipment, certain field equipment including compressors, drilling rigs, land easements and similar arrangements for rights-of-way, and certain gas gathering and gas lift assets. Our short-term leases are primarily comprised of our contractual arrangements with certain vendors for operated drilling rigs and our field compressors. Our primary variable lease includes our field gas gathering and gas lift agreement with a midstream service provider and the lease payments are charged on a volumetric basis at a contractual fixed rate.

The following table summarizes the components of our total lease cost, as determined in accordance with ASC Topic 842, for the twelve months ended December 31, 2019:

Operating lease cost	$	773
Short-term lease cost		36,202
Variable lease cost		23,762
Less: Amounts charged as drilling costs [1]		(33,354)
Total lease cost recognized in the Condensed Consolidated Statement of Operations [2]	$	27,383

[1] Represents the combined gross amounts paid and (i) capitalized as drilling costs for our working interest share and (ii) billed to joint interest partners for their working interest share for short-term leases of operated drilling rigs.

[2] Includes $12.1 million recognized in Gathering, processing and transportation, $ 14.5 million recognized in Lease operating and $ 0.8 million recognized in G&A for the twelve months ended December 31, 2019.

Operating lease rental expense, as determined in accordance with prior GAAP was $2.7 million and $1.0 million, for the years ended December 31, 2018 and 2017, related primarily to field equipment, office equipment and office leases. The substantial difference between operating lease rental expense disclosed in accordance with prior GAAP and that provided in the table above for 2019 in accordance with ASC Topic 842 is attributable to the aforementioned field gas gathering and gas lift agreement which has been determined to be a variable lease under ASC Topic 842.

The following table summarizes supplemental cash flow information, as determined in accordance with ASC Topic 842, related to leases for the twelve months ended December 31, 2019:

Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	659
ROU assets obtained in exchange for lease obligations:		
Operating leases [1]	$	3,325

[1] Includes $2.5 million recognized upon adoption of ASC Topic 842 and $ 0.8 million obtained during the twelve months ended December 31, 2019.

The following table summarizes supplemental balance sheet information related to leases as ofDecember 31, 2019:

ROU assets - operating leases	$	2,740
Current operating lease obligations	$	847
Noncurrent operating lease obligations		2,232
Total operating lease obligations	$	3,079
Weighted-average remaining lease term		
Operating leases		4.1 Years
Weighted-average discount rate		
Operating leases		5.97 %
Maturities of operating lease obligations for the years ending December 31,		
2020	$	847
2021		830
2022		834
2023		833
2024		139
Total undiscounted lease payments		3,483
Less: imputed interest		(404)
Total operating lease obligations	$	3,079

12. Additional Balance Sheet Detail

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

	December 31,			
	2019		2018	
Other current assets:				
Tubular inventory and well materials	$	2,989	$	4,061
Prepaid expenses		1,469		1,064
	$	4,458	$	5,125
Other assets:				
Deferred issuance costs of the Credit Facility, net of amortization	$	3,952	$	2,437
Right-of-use assets - operating leases		2,740		—
Other		32		44
	$	6,724	$	2,481
Accounts payable and accrued liabilities:				
Trade accounts payable	$	30,098	$	16,507
Drilling costs		18,832		22,434
Royalties		44,537		51,212
Production, ad valorem and other taxes		3,244		2,418
Compensation and benefits		5,272		4,489
Interest		730		670
Current operating lease obligations		847		—
Other		2,264		5,970
	$	105,824	$	103,700
Other liabilities:				
Asset retirement obligations	$	4,934	$	4,314
Noncurrent operating lease obligations		2,232		—
Defined benefit pension obligations		873		857
Postretirement health care benefit obligations		343		362
	$	8,382	$	5,533

13. 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 our Credit Facility and Second Lien Facility borrowings. Due to the short-term nature of their maturities, the carrying value of our cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Our derivatives are marked-to-market and presented at their values. The carrying value of our long-term debt, which includes the Credit Facility and the Second Lien Facility, approximated their fair values as they represent variable-rate debt and their interest rates are reflective of market rates.

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:

	As of December 31, 2019			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 4,131	$ —	$ 4,131	$ —
Commodity derivative assets – noncurrent	2,750	—	2,750	—
Liabilities:				
Commodity derivative liabilities – current	$ (23,450)	$ —	$ (23,450)	$ —
Commodity derivative liabilities – noncurrent	(3,385)	—	(3,385)	—

	As of December 31, 2018			
	Fair Value	Fair Value Measurement Classification		
Description	Measurement	Level 1	Level 2	Level 3
Assets:				
Commodity derivative assets – current	$ 34,932	$ —	$ 34,932	$ —
Commodity derivative assets – noncurrent	10,100	—	10,100	—
Liabilities:				
Commodity derivative liabilities – current	$ (991)	$ —	$ (991)	$ —
Commodity derivative liabilities – noncurrent	—	—	—	—

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, 2019, 2018 and 2017.

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 WTI, LLS and MEH crude oil 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.

Non-Recurring Fair Value Measurements

In addition to the fair value measurements applied with respect to the Hunt and Devon Acquisitions, as described in Note 4, the most significant non-recurring fair value measurements utilized in the preparation of our Consolidated Financial Statements are those attributable to the initial determination of AROs associated with the ongoing development of new oil and gas properties. 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.

14. Commitments and Contingencies

The following table sets forth our significant commitments as ofDecember 31, 2019, by category, for the next5 years and thereafter:

Year	Gathering and Intermediate Transportation	Other Commitments
2020	$ 12,962	$ 289
2021	12,962	140
2022	12,962	70
2023	12,962	—
2024	12,962	—
Thereafter	37,789	—
Total	$ 102,599	$ 499

Drilling and Completion Commitments

As of December 31, 2019, we had contractual commitments on a pad-to-pad basis fortwo drilling rigs. Additionally, we have a one-year agreement, effective January 1, 2020, which can be terminated with 30 days' notice by either party, to utilize certain frac services and related materials, withno minimum commitment.

Gathering and Intermediate Transportation Commitments

We have long-term agreements with Nuevo Dos Gathering and Transportation, LLC ("Nuevo G&T") and Nuevo Dos Marketing, LLC ("Nuevo Marketing" and together with Nuevo G&T, collectively "Nuevo"), successor to Republic Midstream, LLC and affiliates, to provide gathering and intermediate pipeline transportation services for a substantial portion of our crude oil and condensate production in South Texas as well as volume capacity support for certain downstream interstate pipeline transportation.

Nuevo is obligated to gather and transport our crude oil and condensate from within a dedicated area in the Eagle Ford via a gathering system and intermediate takeaway pipeline connecting to a downstream interstate pipeline operated by a third party through 2041. We have a minimum volume commitment of 8,000 gross barrels of oil per day to Nuevo through 2031 under the gathering agreement.

Under a marketing agreement, we have a commitment to sell8,000 barrels per day of crude oil (gross) to Nuevo, or to any third party, utilizing Nuevo Marketing's capacity in a downstream interstate pipeline through 2026.

Other Commitments

We have entered into certain contractual arrangements for other products and services. We have purchase commitments for certain materials as well as minimum commitments under information technology licensing and service 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. As of December 31, 2019, we had a reserve in the amount of $0.3 million included in Accounts payable and accrued liabilities for the estimated settlement of disputes with a joint venture partner regarding certain transactions that occurred in prior years.

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, 2019, we have recorded AROs of $4.9 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.

15. Shareholders' Equity

Preferred Stock

As of December 31, 2019 and December 31, 2018, there were 5,000,000 shares of preferred stock authorized with none issued or outstanding.

Common Stock

As of December 31, 2019 and December 31, 2018, there were 15,135,598 and 15,080,594 shares of Common Stock outstanding, respectively, with a par value of $0.01 per share. We have a total of 45,000,000 shares authorized. We have not paid any cash dividends on our common stock. In addition, our Credit Facility and Second Lien Facility have restrictive covenants that limit our ability to pay dividends.

Paid-in Capital

Represents the value of consideration we received in excess of par value for the original issuance of our common stock net of costs directly attributable to the issuance transactions. In addition, paid-in capital includes amounts attributable to the amortized cost of share-based awards that have been granted to our employees and directors, net of any adjustments with the ultimate vesting of such awards.

Accumulated Other Comprehensive Income (Loss)

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 less than $0.1 million for all periods presented.

16. Share-Based Compensation and Other Benefit Plans

We reserved 1,424,600 shares of Common Stock for issuance under the Penn Virginia Corporation Management Incentive Plan for future share-based compensation awards. A total of 360,615 time-vested restricted stock units (“RSUs”) and 113,592 performance restricted stock units (“PRSUs”) have been granted as of December 31, 2019.

We recognized $4.1 million, $4.6 million and $3.8 million of share-based compensation expense for the years ended December 31, 2019, 2018 and 2017, respectively. All of our 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 periods as a non-cash item of expense.

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 RSUs:

	Restricted Stock Units		Weighted-Average Grant Date Fair Value
Balance at beginning of year	208,040	$	47.35
Granted	13,175	$	30.35
Vested	(74,888)	$	39.40
Forfeited	(9,451)	$	51.71
Balance at end of year	136,876	$	49.76

As of December 31, 2019, we had $5.0 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.1 years. The total grant-date fair values of RSUs that vested in2019, 2018 and 2017 was $3.0 million, $3.3 million and $0.8 million, respectively.

Performance Restricted Stock Units

In the years ended December 31, 2019 and December 31, 2017, we granted15,066 and 98,526 PRSUs, respectively to members of our management. There were no PRSUs granted for the year ended December 31, 2018. The PRSUs were issued collectively in one to three separate tranches with individual three-year performance periods beginning in January 2017, 2018, 2019 and 2020, respectively. Vesting of the PRSUs can range from zero to 200% of the original grant based on the performance of our common stock relative to an industry index or for those granted in 2019, a peer group of companies. Due to their market condition, the PRSUs are being charged to expense using graded vesting over a maximum of five years. The fair value of each PRSU award was estimated on their grant dates using a Monte Carlo simulation with a range of $47.70 to $65.28 per PRSU for the 2017 grants and $34.02 for the 2019 grant.

The ranges for the assumptions used in the Monte Carlo model for the PRSUs granted during 2019 and 2017 are presented as follows:

	2019	2017
Expected volatility	49.9 %	59.63% to 62.18%
Dividend yield	0.0%	0.0%
Risk-free interest rate	1.66 %	1.44% to 1.51%

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

	Performance Restricted Stock Units		Weighted-Average Grant Date Fair Value
Balance at beginning of year	89,071	$	58.69
Granted	15,066	$	34.02
Vested	(3,917)	$	63.25
Forfeited	(1,083)	$	63.25
Expired	(19,223)	$	62.92
Balance at end of year	79,914	$	52.73

Executive Transition and Retirement

Effective December 2, 2019, Mr. Steven A. Hartman separated from the Company. In accordance with his separation and transition agreement (“Hartman Separation Agreement”), we recorded a charge of $0.5 million for severance and other cash benefits that were paid in the first quarter of 2020. The Hartman Separation Agreement also provided for the accelerated vesting of certain share-based compensation awards for which we recognized accelerated expense of $0.2 million during the year ended December 31, 2019. Effective February 28, 2018, Mr. Harry Quarls retired from his position as a director and Executive Chairman of the Company. In connection with his retirement, we entered into a separation and consulting agreement (“Quarls Separation Agreement”) whereby Mr. Quarls agreed to provide transition and support services to us through

December 31, 2018. We paid Mr. Quarls $0.3 million under the Quarls Separation Agreement. The Quarls Separation Agreement included a general release of claims and provided for the accelerated vesting of certain share-based compensation awards for which we recognized accelerated expense of $0.6 million during the year ended December 31, 2018. The costs associated with the Hartman and Quarls Separation Agreements, including the share-based compensation charges, were included as a component of "G&A expenses" in our Consolidated Statements of Operations for the years ended December 31, 2019 and 2018, respectively.

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 $0.9 million, $0.6 million, $0.5 million for the years ended December 31, 2019, 2018 and 2017, 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 $0.3 million and $0.3 million are included in the "Accounts payable and accrued expenses" caption on our Consolidated Balance Sheets as of December 31, 2019 and 2018, 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 January 1, 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each year ended December 31, 2019, 2018 and 2017, and is included as a component of "Other, net" in our Statements of Operations. The combined unfunded benefit obligations under these plans were $1.4 million and are included within the "Accounts payable and accrued expenses" (current portion) and "Other liabilities" (noncurrent portion) captions on our Consolidated Balance Sheets as of December 31, 2019 and 2018.

17. Interest Expense

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

	Year Ended December 31,		
	2019	2018	2017
Interest on borrowings and related fees	$ 36,593	$ 32,164	$ 6,995
Accretion of original issue discount [1]	743	680	161
Amortization of debt issuance costs [2]	2,611	2,736	1,961
Capitalized interest	(4,136)	(9,118)	(2,725)
	$ 35,811	$ 26,462	$ 6,392

[1] Includes accretion of original issue discount attributable to the Second Lien Facility (see Note 9).

[2] The year ended December 31, 2017 includes a total of $0.8 million of write-offs attributable to changes in the composition of financial institutions comprising the Credit Facility's bank group in connection with amendments to the Credit Facility (see Note 9).

18. Earnings per Share

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

	Year Ended December 31,		
	2019	2018	2017
Net income – basic and diluted	$ 70,589	$ 224,785	$ 32,662
Weighted-average shares – basic	15,110	15,059	14,996
Effect of dilutive securities [1]	16	233	67
Weighted-average shares – diluted	15,126	15,292	15,063

[1] Represents a combination of unvested RSUs and PRSUs that are dilutive with the exception of December 31, 2019 at which time all of our unvested PRSUs were determined to be at a zero percent vesting level due to the relative performance of our common stock.

Supplemental Quarterly Financial Information (Unaudited)

2019	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues [1]	$ 105,228	$ 122,767	$ 119,304	$ 123,917
Operating income	$ 38,668	$ 47,888	$ 40,040	$ 50,225
Income (loss)	$ (38,697)	$ 51,625	$ 54,362	$ 3,299
Income (loss) per share – basic [2]	$ (2.56)	$ 3.42	$ 3.60	$ 0.22
Income (loss) per share – diluted [2]	$ (2.56)	$ 3.40	$ 3.59	$ 0.22
Weighted-average shares outstanding:				
Basic	15,098	15,106	15,110	15,126
Diluted	15,098	15,162	15,160	15,131

2018	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues [3]	$ 77,211	$ 111,580	$ 127,185	$ 124,856
Operating income	$ 33,912	$ 55,886	$ 64,036	$ 54,921
Income (loss) [4]	$ 10,295	$ (2,521)	$ 16,276	$ 200,735
Income (loss) per share – basic [2]	$ 0.68	$ (0.17)	$ 1.08	$ 13.32
Income (loss) per share – diluted [2]	$ 0.68	$ (0.17)	$ 1.06	$ 13.10
Weighted-average shares outstanding:				
Basic	15,042	15,058	15,062	15,075
Diluted	15,081	15,058	15,344	15,328

[1] Includes gains (losses) on sales of assets of less than $0.1 million, less than $0.1 million, less than $0.1 million and $(0.1) million during the quarters ended March 31, 2019, June 30, 2019, September 30, 2019 and December 31, 2019, respectively.

[2] 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.

[3] Includes gains (losses) on sales of assets of less than $0.1 million, less than $0.1 million, less than $0.1 million and $(0.3) million during the quarters ended March 31, 2018, June 30, 2018, September 30, 2018 and December 31, 2018, respectively.

[4] The quarter ended December 31, 2018 includes a mark-to-market gain on derivatives of $149.2 million.

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 were prepared by our independent third party engineers, DeGolyer and MacNaughton, Inc. utilizing data compiled by us. DeGolyer and MacNaughton, Inc. is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists. Our Vice President, Engineering is primarily responsible for overseeing the preparation of the reserve estimate by DeGolyer and MacNaughton, 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, 2016	36,611	6,765	36,682	49,490
Revisions of previous estimates	(5,735)	(2,071)	(10,468)	(9,550)
Extensions and discoveries	23,850	3,571	16,840	30,228
Production	(2,764)	(523)	(2,949)	(3,779)
Purchase of reserves	3,867	1,122	7,162	6,183
December 31, 2017	55,829	8,864	47,267	72,572
Revisions of previous estimates	(19,096)	(1,789)	(9,608)	(22,487)
Extensions and discoveries	48,119	11,737	59,447	69,764
Production	(6,077)	(1,004)	(5,181)	(7,944)
Purchase of reserves	11,278	969	5,827	13,218
Sale of reserves in place	(397)	(733)	(6,259)	(2,173)
December 31, 2018	89,656	18,044	91,493	122,950
Revisions of previous estimates	(24,709)	(4,055)	(25,440)	(33,006)
Extensions and discoveries	40,190	6,575	31,045	51,939
Production	(7,453)	(1,491)	(7,067)	(10,121)
Purchase of reserves	1,212	81	418	1,363
December 31, 2019	98,896	19,154	90,449	133,125
Proved Developed Reserves:				
December 31, 2017	22,412	4,882	27,229	31,832
December 31, 2018	35,190	6,279	31,833	46,774
December 31, 2019	40,641	8,846	41,808	56,455
Proved Undeveloped Reserves:				
December 31, 2017	33,417	3,982	20,038	40,740
December 31, 2018	54,466	11,765	59,660	76,176
December 31, 2019	58,255	10,308	48,641	76,670

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

Year Ended December 31, 2019

In 2019, our proved reserves increased by 10.2 MMBOE. due primarily to substantial changes in our development plans from the southeast portion of our acreage position in the Eagle Ford to the central region. The overall shift to this region will allow us to develop wells with a lower gas content than what we were experienced in the southeast region through the first half of 2019. After achieving more favorable results with certain wells in the central region, we proceeded to drill a total of 11 gross wells, or approximately 23 percent of our total wells drilled in 2019, in the central region that were not considered proved undeveloped locations at the end of 2018. Accordingly, we have prioritized our drilling schedule to exploit these more favorable opportunities. While we still believe that the southeastern sites have economic merit, despite a higher gas content, we have deferred drilling them beyond the five-year window which results in revisions due to timing. Accordingly, our five-year drilling plan is heavily weighted to the lower gas content central region.

We had downward revisions of 33.0 MMBOE including: (i) 32.1 MMBOE due to a change in timing beyond five years attributable to our development plans as discussed above, as well as a reduction of drilling rigs from three to two, combining certain wells into extended reach lateral locations and other reductions due to changes in the plan of development, (ii) 2.7 MMBOE due to 15 percent lower crude oil pricing from $65.56 per barrel to $55.67 per barrel and (iii) 1.6 MMBOE due to reductions in lateral length and net revenue interests partially offset by (iv) 3.4 MMBOE due to improved performance of certain proved undeveloped wells and proved undeveloped wells transferred to proved developed net of lower performance associated with certain existing proved developed wells including those reclassified to proved non-producing. Extensions and discoveries of 51.9 MMBOE are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher estimated ultimate reserves (“EUR”) per lateral foot as well the addition of certain non-operated royalty wells. We acquired 1.4 MMBOE in connection with the acquisition of certain non-operating partners working interests in locations in which we are the operator.

Year Ended December 31, 2018

In 2018, our proved reserves increased by 50.4 MMBOE. The overall increase over our proved reserves at the end of 2017 is due primarily to a significant shift in our development plans from the northwest portion of our acreage position in the Eagle Ford to the southeast region. The performance of our wells drilled in the southeast region in the first half of the year was the impetus to our redirecting of resources and replication, to the extent practical, of our drilling and completion design techniques for the second half of 2018. Of the 53 gross wells we drilled in 2018, 19 gross wells were not proved undeveloped locations at the end of 2017. Accordingly, our five-year drilling plan is heavily weighted to the southeast region.

We had downward revisions of 22.5 MMBOE including: (i) 21.1 MMBOE due to the loss of certain locations resulting from changes in the drilling locations and timing attributable to our development plans as discussed above and (ii) 4.4 MMBOE due to well performance partially offset by (iii) 1.2 MMBOE due to improved treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units and (iv) 1.8 MMBOE of other changes, primarily price-related. Extensions and discoveries of 69.8 MMBOE are substantially attributable to geographical shift in our development plan, greater utilization of extended reach laterals, increasing the length of such laterals, higher EUR estimates per lateral foot and higher net revenue interests due to the Hunt Acquisition. We acquired 13.2 MMBOE in connection with the Hunt Acquisition and we sold 2.2 MMBOE in connection with our exit from the Mid-Continent region.

Year Ended December 31, 2017

We had downward revisions of 9.6 MMBOE as a result of the following: (i) downward revisions of 6.5 MMBOE due primarily to reduced treatable lateral lengths in certain locations due primarily to reconfiguration of the planned drilling units partially offset by improved performance, (ii) downward revisions of 4.7 MMBOE to our proved undeveloped reserves due to the loss of certain locations resulting from changes in the timing and drilling locations attributable to our development plans partially offset by (iii) 1.6 MMBOE due to improved well performance. Extensions and discoveries of 30.2 MMBOE are entirely attributable to our expanded development plan including adding a third rig to our drilling program and the corresponding increase in the number of drilling locations that we are planning to drill in the next five years. We acquired 6.2 MMBOE in connection with the Devon Acquisition. An additional 1.0 MMBOE attributable to the Devon Acquisition was determined in our year-end assessment consistent with our development plans and is included in the aforementioned extensions and discoveries.

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:

	December 31,		
	2019	2018	2016
Oil and gas properties:			
Proved	$ 1,409,219	$ 1,037,993	$ 460,029
Unproved	53,200	63,484	117,634
Total oil and gas properties	1,462,419	1,101,477	577,663
Other property and equipment	21,317	16,462	10,057
Total capitalized costs relating to oil and gas producing activities	1,483,736	1,117,939	587,720
Accumulated depreciation and depletion	(364,716)	(191,802)	(60,247)
Net capitalized costs relating to oil and gas producing activities [1]	$ 1,119,020	$ 926,137	$ 527,473

[1] Excludes property and equipment attributable to our corporate operations which is comprised of certain capitalized hardware, software, leasehold improvements and office furniture and fixtures.

Costs Incurred in Certain Oil and Gas Activities

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

	Year Ended December 31,		
	2019	2018	2017
Development costs [1]	$ 355,925	$ 416,037	$ 135,360
Proved property acquisition costs [2]	6,051	86,514	43,151
Unproved property acquisition costs [3]	7,570	30,637	153,905
Exploration costs [4]	363	377	696
	$ 369,909	$ 533,565	$ 333,112

[1] Includes plugging and abandonment asset additions of $0.3 million, $0.7 million and $0.3 million and capitalized internal costs of $3.6 million, $3.3 million and $2.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

[2] Includes plugging and abandonment assets acquired of $0.1 million in the year ended December 31, 2019 and $0.4 million and $0.5 million acquired in the Hunt and Devon Acquisitions during the years ended December 31, 2018 and 2017, respectively. Also includes capitalized internal costs of $0.5 million, $0.4 million and $0.3 million for the years ended December 31, 2019, 2018 and 2017, respectively.

[3] Includes capitalized interest of $4.1 million, $9.1 million and $2.7 million for the years ended December 31, 2019, 2018 and 2017, respectively as well as unproved properties acquired in the Hunt and Devon Acquisitions during the years ended December 31, 2018 and 2017.

[4] Includes geological costs, geophysical costs (seismic) and delay rentals for all periods presented.

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 below 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
December 31, 2017	$ 51.34	$ 18.48	$ 2.98
December 31, 2018	$ 65.56	$ 23.60	$ 3.10
December 31, 2019	$ 55.67	$ 13.36	$ 2.58

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,		
	2019	2018	2017
Future cash inflows	$ 6,260,292	$ 6,719,145	$ 3,091,366
Future production costs	(1,792,891)	(1,852,168)	(1,069,910)
Future development costs	(1,174,215)	(1,208,815)	(689,998)
Future net cash flows before income tax	3,293,186	3,658,162	1,331,458
Future income tax expense	(334,451)	(413,137)	(84,350)
Future net cash flows	2,958,735	3,245,025	1,247,108
10% annual discount for estimated timing of cash flows	(1,469,853)	(1,621,135)	(656,624)
Standardized measure of discounted future net cash flows	$ 1,488,882	$ 1,623,890	$ 590,484

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,		
	2019	2018	2017
Sales of oil and gas, net of production costs	$ (374,694)	$ (361,478)	$ (118,137)
Net changes in prices and production costs	(402,616)	585,737	170,488
Changes in future development costs	415,193	206,901	30,692
Extensions and discoveries	459,501	809,880	131,060
Development costs incurred during the period	253,982	204,160	74,880
Revisions of previous quantity estimates	(515,345)	(483,091)	(122,357)
Purchases of reserves-in-place	12,241	86,128	80,878
Sale of reserves-in-place	—	(8,912)	—
Changes in production rates and all other	(194,453)	60,160	12,161
Accretion of discount	176,935	60,897	31,755
Net change in income taxes	34,248	(126,976)	(18,486)
Net increase (decrease)	(135,008)	1,033,406	272,934
Beginning of year	1,623,890	590,484	317,550
End of year	$ 1,488,882	$ 1,623,890	$ 590,484

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

Not applicable.

Item 9A Controls and Procedures

(a) Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of December 31, 2019. 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 within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to the issuer's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of December 31, 2019, such disclosure controls and procedures were effective.

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

Our management 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, 2019. 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.

Based on that assessment, our management has concluded that, as ofDecember 31, 2019, our internal control over financial reporting was effective.

(c) Attestation Report of the Registered Public Accounting Firm

Grant Thornton LLP, the independent registered public accounting firm that audited and reported on the consolidated financial statements contained in this Form 10-K, has issued an attestation report on the internal control over financial reporting as of December 31, 2019, which is included in Item 8 of this Annual Report on Form 10-K.

(d) Changes in Internal Control Over Financial Reporting

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

Item 9B Other Information

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.

We have adopted a Code of Business Conduct and Ethics that applies to all of our directors, officer and employees, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Business Conduct and Ethics is posted on our website located at https://ir.pennvirginia.com/governance-docs. We intend to disclose future amendments to certain provisions of the Code of Business Conduct and Ethics, and waivers of the Code of Business Conduct and Ethics granted to executive officers and directors, on the website within four business days following the date of the amendment or waiver.

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 Stockholder 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 Exhibits and Financial Statement Schedules

(1) Financial Statements

The financial statements filed herewith are listed in the Index to Consolidated Financial Statements on page 58 of this Annual Report on Form 10-K.

(2) Exhibits

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.

(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 15, 2016).
(3.2)	Fourth Amended and Restated Bylaws of Penn Virginia Corporation effective as of December 20, 2019 (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed on December 27, 2019).
(4.1)#	Description of Common Stock.
(10.1)	Master Agreement, Borrowing Base Increase Agreement, and Amendment No. 6 to Credit Agreement, dated as of May 7, 2019, among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, as parent, the subsidiaries of the borrower party thereto, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 8, 2019).
(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 15, 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 15, 2016).
(10.4)	Credit Agreement, dated as of September 29, 2017, by and among Penn Virginia Holding Corp., as borrower, Penn Virginia Corporation, the lenders party thereto and Jefferies Finance LLC, as administrative agent, collateral agent and sole lead arranger (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.5)	Pledge and Security Agreement, dated as of September 29, 2017, by Penn Virginia Holding Corp., Penn Virginia Corporation and the other grantors party thereto in favor of Jefferies Finance LLC, as administrative agent and collateral agent for the ratable benefit of the secured parties thereunder (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.6)	Intercreditor Agreement, dated as of September 29, 2017, by and among Penn Virginia Holding Corp., Penn Virginia Corporation, the subsidiaries of Penn Virginia Holding Corp. party thereto, Wells Fargo Bank, National Association and Jefferies Finance LLC (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on October 5, 2017).
(10.7)	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/A filed on November 28, 2016).
(10.8.1)	Amendment No. 1 to the Second Amended and Restated Construction and Field Gathering Agreement dated as of April 13, 2017 but effective August 1, 2016 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas, L.P. (incorporated by reference to Exhibit 10.4.1 to Registrant's Registration Statement on Form S-3/A (Amendment No. 2) filed on May 2, 2017).
(10.8.2)	Second Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of July 2, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.8.3)	Third Amendment to Second Amended and Restated Construction and Field Gathering Agreement dated as of December 14, 2018 by and between Republic Midstream, LLC and Penn Virginia Oil & Gas L.P. (incorporated by reference to Exhibit 10.9.3 to Registrant's Annual Report on Form 10-K filed on February 27, 2019).
(10.9)	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/A filed on November 28, 2016).
(10.9.1) †	First Amendment to First Amended and Restated Crude Oil Marketing Agreement dated as of July 2, 2018 by and between Penn Virginia Oil & Gas, L.P. and Republic Midstream Marketing, LLC.(incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.10)*	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).
(10.10.1)*	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).

(10.10.2)*	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).
(10.10.3)*	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).
(10.11)*	Penn Virginia Corporation 2019 Management Incentive Plan (incorporated by reference to Appendix A to Company's Definitive Proxy Statement for its 2019 Annual General Meeting of Shareholders filed on July 1, 2019).
(10.11.2)*#	Form of Officer Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan.
(10.11.3)*#	Form of Performance Restricted Stock Unit Award Agreement under 2019 Management Incentive Plan.
(10.11.4)*	Form of Director Restricted Stock Award Agreement under 2019 Management Incentive Plan (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on September 6, 2019).
(10.12)*	Separation and Transition Agreement, entered into as of July 1, 2019, between Penn Virginia Corporation and Steven A. Hartman (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on July 8, 2019).
(10.13)*	Penn Virginia Corporation 2017 Special Severance Plan Amended and Restated Effective July 18, 2018 (incorporated by reference to Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q filed on November 8, 2018).
(10.14)	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 DeGolyer and MacNaughton.
(31.1)#	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)#	Certification Pursuant to 18 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 19, 2020 concerning evaluation of oil and gas reserves.
(101.INS)#	Inline XBRL Instance Document
(101.SCH)#	Inline XBRL Taxonomy Extension Schema Document
(101.CAL)#	Inline XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF)#	Inline XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB)#	Inline XBRL Taxonomy Extension Label Linkbase Document
(101.PRE)#	Inline XBRL Taxonomy Extension Presentation Linkbase Document
(104)#	The cover page of Penn Virginia Corporation's Annual Report on Form 10-K for the year ended December 31, 2019, formatted in Inline XBRL (included within the Exhibit 101 attachments).

* Management contract or compensatory plan or arrangement.
\# Filed herewith.
† Confidential treatment has been requested for this exhibit and confidential portions have been filed separately with the Securities and Exchange Commission.
†† Furnished herewith.

Item 16 Form 10-K Summary

None.

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/ RUSSELL T KELLEY, JR.
		Russell T Kelley, Jr.
		Senior Vice President and Chief Financial Officer
		(Principal Financial Officer)
February 28, 2020	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**	Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2020
/s/ RUSSELL T KELLEY, JR. **Russell T Kelley, Jr.**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2020
/s/ TAMMY L. HINKLE **Tammy L. Hinkle**	Vice President and Controller (Principal Accounting Officer)	February 28, 2020
/s/ TIFFANY THOM CEPAK **Tiffany Thom Cepak**	Director	February 28, 2020
/s/ DARIN G. HOLDERNESS **Darin G. Holderness**	Chairman of the Board	February 28, 2020
/s/ V. FRANK POTTOW **V. Frank Pottow**	Director	February 28, 2020
/s/ JERRY R. SCHUYLER **Jerry R. Schuyler**	Director	February 28, 2020
/s/ BRIAN STECK **Brian Steck**	Director	February 28, 2020
/s/ JEFFREY WOJAHN **Jeffrey Wojahn**	Director	February 28, 2020

Exhibit 4.1

DESCRIPTION OF COMMON STOCK REGISTERED
UNDER SECTION 12 OF THE EXCHANGE ACT OF 1934

The following is a description of the rights of the common stock (the "Common Stock") of Penn Virginia Corporation (the "Company," "we," "our" or "us"), related provisions of the Company's Second Amended and Restated Articles of Incorporation ("Articles") and Fourth Amended and Restated Bylaws ("Bylaws") and applicable Virginia law. This description is intended as a summary and is qualified in its entirety by, and should be read in conjunction with, our Articles, our Bylaws and applicable Virginia law. Our Articles and our Bylaws are incorporated by reference as exhibits to the Annual Report on Form 10-K, of which this Exhibit 4.1 is a part.

The Company's authorized capital stock is 50,000,000 shares. Those shares consist of 5,000,000 authorized shares of preferred stock (par value $0.01 per share), and 45,000,000 authorized shares of common stock (par value $0.01 per share).

Our common stock is listed on the Nasdaq Global Select Market under the symbol "PVAC."

Common Stock

Dividends

Subject to the rights of any series of preferred stock that we may issue, the holders of common stock may receive dividends when declared by the Board. Dividends may be paid in cash, in property or in shares of stock, or in any combination thereof.

Fully Paid

All outstanding shares of common stock are fully paid and non-assessable.

Voting Rights

Subject to the special voting rights of any preferred stock that we may issue, the holders of common stock may vote one vote for each share held together as a single class in the election of directors and on all other matters voted upon by our shareholders. In uncontested elections, directors are elected by a majority of the votes cast in the election for such director nominee; in contested elections, directors are elected by a plurality of the votes cast in the election for such director nominee. Holders of common stock may not cumulate their votes in the elections of directors. The affirmative vote of more than two-thirds of our outstanding shares of common stock is required for amendments to our Articles, the approval of mergers, statutory share exchanges, certain sales or other dispositions of assets outside the usual and regular course of business, conversions, domestications and dissolutions. However, holders of our common stock are not entitled to vote on any amendment to our Articles that relates solely to the terms of any one or more series of preferred stock. The affirmative vote of at least 67% of our outstanding shares of common stock is required to amend our Articles.

Liquidation Rights

If we dissolve our business, either voluntarily or not, holders of common stock will share equally in the assets remaining after we pay our creditors and preferred shareholders.

Other Rights

The holders of common stock have no preemptive rights to purchase our shares of common stock. Shares of common stock are not subject to any redemption or sinking fund provisions and are not convertible into any of our other securities.

Preferred Stock

The Board is authorized, without approval of shareholders, issue one or more series of preferred stock. Subject to the provisions of our Articles and limitations prescribed by law, the Board may adopt an amendment to our Articles setting the number of shares of each series and the rights, preferences and limitations of each series, including the dividend rights, voting rights, conversion rights, redemption rights and any liquidation preferences of any wholly unissued series of preferred stock, the number of shares constituting each series and the terms and conditions of issue.

Undesignated preferred stock may enable the Board to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of the holders of our common stock. For example, any preferred stock issued may rank prior to our common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of common stock. As a result, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock or any existing preferred stock.

Anti-Takeover Provisions

Certain provisions in our Articles and our Bylaws, as well as certain provisions of Virginia law, may make more difficult or discourage a takeover of our business.

Certain Provisions of Our Articles of Incorporation and Our Bylaws

Shareholder Action by Unanimous Consent. Any action that could be taken by shareholders at a meeting may be taken, instead, without a meeting and without notice if a consent in writing is signed by all the shareholders entitled to vote on the action.

Blank Check Preferred Stock. Our Articles authorize the issuance of blank check preferred stock. As described above under "—Preferred Stock," the Board can set the voting rights, redemption rights, conversion rights and other rights relating to such preferred stock and could issue such stock in either private or public transactions. In some circumstances, the blank check preferred stock could be issued and have the effect of preventing a merger, tender offer or other takeover attempt that the Board opposes.

Vacancies in the Board. Subject to the rights of any preferred stock, any vacancy in the Board resulting from any death, resignation, retirement, disqualification, removal from office or newly created directorship resulting from an increase in the authorized number of directors or otherwise may be filled by majority vote of the remaining directors then in office, even if less than a quorum, or shareholders.

Special Meetings of Shareholders. Special meetings of shareholders may be called at any time and from time to time only upon the written request of the Board, the chairman of the Board or the holders of a majority of our outstanding common stock.

Advance Notice Requirements for Shareholder Director Nominations and Shareholder Business. Our Bylaws require that advance notice of shareholder director nominations and shareholder business for annual meetings be made in writing and given to our corporate secretary, together with certain specified information, not less than 90 days nor more than 120 days before the anniversary of the immediately preceding annual meeting of shareholders, subject to other timing requirements as specified in our Bylaws.

Virginia Anti-Takeover Statutes and Other Virginia Laws

Control Share Acquisitions Statute. Under the Virginia control share acquisitions statute, shares acquired in an acquisition that would cause an acquiror's voting strength to meet or exceed any of three thresholds (20%, 33 1/3% or 50%) have no voting rights unless (1) those rights are granted by a majority vote of all outstanding shares other than those held by the acquiror or any officer or employee director of the corporation or (2) the articles of incorporation or bylaws of the corporation provide that the provisions of the control share acquisitions statute do not apply to acquisitions of its shares. An acquiring person that owns five percent or more of the corporation's voting stock may require that a special meeting of the shareholders be held to consider the grant of voting rights to the shares acquired in the control share acquisition. This regulation was designed to deter certain takeovers of Virginia public corporations. Virginia law permits corporations to opt out of the control share acquisition statute. We have not opted out.

Affiliated Transactions. Under the Virginia anti-takeover law regulating affiliated transactions, material acquisition transactions between a Virginia corporation and any holder of more than 10% of any class of its outstanding voting shares are required to be approved by the holders of at least two-thirds of the remaining voting shares. Affiliated transactions subject to this approval requirement include mergers, share exchanges, material dispositions of corporate assets not in the ordinary course of business, any dissolution of the corporation proposed by or on behalf of a 10% holder or any reclassification, including reverse stock splits, recapitalization or merger of the corporation with its subsidiaries, that increases the percentage of voting shares owned beneficially by a 10% holder by more than five percent. For three years following the time that a shareholder becomes an interested shareholder, a Virginia corporation cannot engage in an affiliated transaction with the interested shareholder without approval of two-thirds of the disinterested voting shares and a majority of the disinterested directors. A disinterested director is a director who was a director on the date on which an interested shareholder became an interested shareholder or was recommended for election or elected by a majority of the disinterested directors then on the board. After three years, the approval of the disinterested directors is no longer required. The provisions of this statute do not apply if a majority of disinterested directors approve the acquisition of shares making a person an interested shareholder. As permitted by Virginia law, we have opted out of the affiliated transactions provisions.

Director Standards of Conduct. Under Virginia law, directors must discharge their duties in accordance with their good faith business judgment of the best interests of the corporation. Directors may rely on the advice or acts of others, including officers, employees, attorneys, accountants and board committees if they have a good faith belief in their competence. Virginia law provides that, in determining the best interests of the corporation, a director may consider the possibility that those interests may best be served by the continued independence of the corporation.

Exhibit 10.11.2

OFFICER RESTRICTED STOCK UNIT AWARD AGREEMENT

PENN VIRGINIA CORPORATION
2019 MANAGEMENT INCENTIVE PLAN

This Officer Restricted Stock Unit Award Agreement (this "Agreement") is made as of the [●] day of [●] 20[●] (the "Grant Date") between Penn Virginia Corporation (the "Company"), and [●] ("Participant"), and is made pursuant to the terms of the Penn Virginia Corporation 2019 Management Incentive Plan (as the same may be amended, the "Plan"). Any capitalized term used herein but not defined shall have the meaning set forth in the Plan.

Section 1. Grant of Restricted Stock Units. The Company hereby grants to Participant a Restricted Stock Unit Award consisting of [●] restricted stock units ("Restricted Stock Units"), subject to the terms and conditions set forth in this Agreement and the Plan. Subject to the terms and conditions set forth in this Agreement and the Plan, each Restricted Stock Unit represents the right to receive one share of Common Stock.

Section 2. Vesting of the Restricted Stock Units. Except as otherwise provided herein, one-third of the Restricted Stock Units will vest on each of the first three anniversaries of the Grant Date, subject to Participant's continuous Service with the Company through the applicable vesting date.

Section 3. Termination of Service. Upon the occurrence of a termination of Participant's Service, the Restricted Stock Units shall be treated as set forth below.

(a) Change in Control Termination. Upon the occurrence of a termination of Participant's Service by the Company or an Affiliate, including any successor thereto, without Cause (and not as a result of death or Disability) or by the Participant with Good Reason (as defined below), in either case during the twelve-month period following the consummation of a Change in Control, all unvested Restricted Stock Units shall immediately vest in full.

For purposes of this Agreement "Good Reason" has the meaning ascribed to such term in any employment agreement between the Participant and the Company or, if none, means the occurrence of any of the following events or conditions: (i) a material diminution in the Participant's title, authority, duties or responsibilities from those in effect on the Grant Date, (ii) a material reduction in the Participant's base salary or annual cash incentive compensation opportunity from that in effect on the Grant Date or (iii) the relocation of the Participant to a location more than fifty (50) miles from the location at which the Participant is based on the Grant Date; provided, however, that such event or condition remains uncured forty-five (45) days following Participant's delivery to the Company of written notice of the specific grounds for Good Reason, which notice is delivered within forty-five (45) days following the initial occurrence of the event or condition giving rise to Good Reason.

(b) Qualifying Termination. Upon the occurrence of a termination of Participant's Service by the Company or an Affiliate:

i. without Cause or by the Participant for Good Reason, Participant will vest in the next tranche of Restricted Stock Units scheduled to vest under Section 2 hereof immediately following the date of such termination; or

ii. due to Participant's death or Disability (as defined below), the number of Restricted Stock Units that vest shall be equal to (A)(x) the total number of Restricted Stock Units times (y) a fraction the numerator of which is that number of days during the period commencing on the Grant Date and ending on the date of death or the date on which employment is terminated, as applicable, and the denominator of which is one thousand ninety-five (1,095) less (B) the number of Restricted Stock Units that have already vested pursuant to Section 2(a). Any Restricted Stock Units that remain unvested following the application of this section shall be forfeited and cancelled and Participant shall not be entitled to any compensation or other amount with respect thereto. For purposes of this Agreement, "Disability" shall mean a disability that entitles the Participant to benefits under the Company's long-term disability plan, as may be in effect from time to time, as determined by the plan administrator of the long-term disability plan.

(c) Other Terminations of Service. Upon the occurrence of a termination of Participant's Service for any reason other than as provided in Section 3(a) or Section 3(b), all unvested Restricted Stock Units shall be immediately forfeited and cancelled and Participant shall not be entitled to any compensation or other amount with respect thereto.

Section 4. Settlement. Any Restricted Stock Units that become vested and non-forfeitable pursuant to Section 2 or Section 3 ("Vested RSUs") shall be settled on or as soon as administratively practicable after the applicable vesting date, but in no event later than March 15th of the year following the year in which such vesting date occurs. Vested RSUs will be settled, unless otherwise determined by the Committee, by the Company through the delivery to the Participant of a number of shares of Common Stock equal to the number of Vested RSUs. No fractional shares of Common Stock shall be issued, and the value of any such fractional share shall be paid to Participant in cash at Fair Market Value.

Section 5. Restrictions on Transfer. Except as permitted under Section 11 of the Plan, no Restricted Stock Units may be transferred, pledged, assigned, hypothecated or otherwise disposed of in any way by Participant, except by will or by the laws of descent and distribution. In the event that Participant becomes legally incapacitated, Participant's rights with respect to the Restricted Stock Units shall be exercisable by Participant's legal guardian or legal representative. The

Restricted Stock Units shall not be subject to execution, attachment or similar process. Any attempted assignment, transfer, pledge, hypothecation or other disposition of the Restricted Stock Units contrary to the provisions hereof, and the levy of any execution, attachment or similar process upon any Restricted Stock Units, shall be null and void and without effect.

Section 6. Investment Representation. Upon any acquisition of the shares of Common Stock underlying the Restricted Stock Units at a time when there is not in effect a registration statement under the Securities Act relating to the shares of Common Stock, Participant hereby represents and warrants, and by virtue of such acquisition shall be deemed to represent and warrant, to the Company that such shares of Common Stock shall be acquired for investment and not with a view to the distribution thereof, and not with any present intention of distributing the same, and Participant shall provide the Company with such further representations and warranties as the Company may reasonably require in order to ensure compliance with applicable federal and state securities, blue sky and other laws. No shares of Common Stock underlying the Restricted Stock Units shall be acquired unless and until the Company and/or Participant have complied with all applicable federal or state registration, listing and/or qualification requirements and all other requirements of law or of any regulatory agencies having jurisdiction, unless the Committee reasonably determines that Participant may acquire such shares of Common Stock pursuant to an exemption from registration under the applicable securities laws.

Section 7. Adjustments. The Restricted Stock Units granted hereunder shall be subject to the provisions of Section 4.2 of the Plan.

Section 8. No Right of Continued Service. Nothing in the Plan or this Agreement shall confer upon Participant any right to continued Service with the Company or any Affiliate.

Section 9. Limitation of Rights; Dividend Equivalents. Participant shall not have any privileges of a stockholder of the Company with respect to any Restricted Stock Units, including, without limitation, any right to vote any shares of Common Stock underlying such Restricted Stock Units or to receive dividends or other distributions or payments of any kind in respect thereof or exercise any other right of a holder of any such securities, unless and until there is a date of settlement and issuance to Participant of the underlying shares of Common Stock. Notwithstanding the foregoing, the Restricted Stock Unit Award granted hereunder is hereby granted in tandem with corresponding dividend equivalents with respect to each share of Common Stock underlying the Restricted Stock Unit Award granted hereunder (each, a "Dividend Equivalent"), which Dividend Equivalent shall remain outstanding from the Grant Date until the earlier of the settlement or forfeiture of the Restricted Stock Unit to which it corresponds. Participant shall be entitled to accrue payments equal to dividends declared, if any, on the Common Stock underlying the Restricted Stock Unit to which such Dividend Equivalent relates, payable in cash and subject to the vesting of the Restricted Stock Unit to which it relates, at the time the Common Stock underlying the Restricted Stock Unit is settled and delivered to Participant pursuant to Section 4; provided, however, if any dividends or distributions are paid in shares of Common Stock, the shares of Common Stock shall be deposited with the Company, shall be deemed to be part of the Dividend Equivalent, and shall be subject to the same vesting requirements, restrictions on transferability and forfeitability as the Restricted Stock Units to which they correspond. Dividend Equivalents shall not entitle Participant to any payments relating to dividends declared after the earlier to occur of the settlement or forfeiture of the Restricted Stock Units underlying such Dividend Equivalents.

Section 10. Construction. The Restricted Stock Unit Award granted hereunder is granted pursuant to the Plan and is in all respects subject to the terms and conditions of the Plan. Participant hereby acknowledges that a copy of the Plan has been delivered to Participant and accepts the Restricted Stock Unit Award hereunder subject to all terms and provisions of the Plan, which are incorporated herein by reference. In the event of a conflict or ambiguity between any term or provision contained herein and a term or provision of the Plan, the Plan will govern and prevail. The construction of and decisions under the Plan and this Agreement are vested in the Board, whose determinations shall be final, conclusive and binding upon Participant.

Section 11. Notices. Any notice hereunder by Participant shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof by the General Counsel of the Company at the Company's principal executive offices. Any notice hereunder by the Company shall be given to Participant in writing at the most recent address as Participant may have on file with the Company.

Section 12. Governing Law. This Agreement shall be construed and enforced in accordance with, the laws of the Commonwealth of Virginia, without giving effect to the choice of law principles thereof.

Section 13. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed to be an original but all of which together shall constitute one and the same instrument.

Section 14. Binding Effect. This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators, successors and assigns.

Section 15. Section 409A. This Agreement is intended to comply with Section 409A of the Code ("Section 409A") or an exemption thereunder and shall be construed and administered in accordance with Section 409A. Notwithstanding any other provision of the Plan or this Agreement, payments provided under this Agreement may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any payments under this Agreement that may be excluded from Section 409A shall be excluded from Section 409A to the maximum extent possible. The Restricted Stock Units granted hereunder shall be subject to the provisions of Section 13.3 of the Plan. Notwithstanding the foregoing, the Company makes no representations that the payments and benefits provided under this Agreement comply with Section 409A, and in no event shall the Company or any of its Subsidiaries or Affiliates be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by Participant on account of non-compliance with Section 409A or otherwise.

Section 16. Entire Agreement. Participant acknowledges and agrees that this Agreement and the Plan constitute the entire agreement between the parties with respect to the subject matter hereof and thereof, superseding any and all prior agreements whether verbal or otherwise, between the parties with respect to such subject matter. Except as otherwise expressly set forth herein, the terms and conditions of the Restricted Stock Units will not be governed or affected by the terms of Participant's employment agreement or offer letter, or any severance, change of control or similar agreement or policy of the Company or any Affiliate to which Participant may be party or by which he or she may be covered.

Section 17. **Clawback.** The Restricted Stock Unit Award will be subject to recoupment in accordance with any clawback or recoupment policy of the Company, including without limitation, any clawback or recoupment policy that the Company is required to adopt pursuant to the listing standards of any national securities exchange or association on which the Company's securities are listed or as is otherwise required by the Dodd-Frank Wall Street Reform and Consumer Protection Act or other applicable law.

Section 18. **Tax Withholding**. This Agreement and the Restricted Stock Units shall be subject to withholding in accordance with Section 13.4 of the Plan, including the net settlement provision therein, Section 13.4(c).

Section 19. **Certain Excise Taxes.** Notwithstanding anything to the contrary in this Agreement, if Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code), and the payments provided for under this Agreement, together with any other payments and benefits which Participant has the right to receive from the Company or any of its Affiliates, would constitute a "parachute payment" (as defined in Section 280G(b)(2) of the Code), then the payments provided for under this Agreement shall be either (a) reduced (but not below zero) so that the present value of such total amounts and benefits received by Participant from the Company and its Affiliates will be one dollar ($1.00) less than three times Participant's "base amount"(as defined in Section 280G(b)(3) of the Code) and so that no portion of such amounts and benefits received by Participant shall be subject to the excise tax imposed by Section 4999 of the Code or (b) paid in full, whichever produces the better net after-tax position to Participant (taking into account any applicable excise tax under Section 4999 of the Code and any other applicable taxes). The determination as to whether any such reduction in the amount of the payments provided hereunder is necessary shall be made by the Company in good faith. If a reduced payment is made or provided and through error or otherwise that payment, when aggregated with other payments and benefits from the Company (or its Affiliates) used in determining if a parachute payment exists, exceeds one dollar ($1.00) less than three times Participant's base amount, then Participant shall immediately repay such excess to the Company upon notification that an overpayment has been made. Nothing in this Agreement shall require the Company (or any of its Affiliates) to be responsible for, or have any liability or obligation with respect to, Participant's excise tax liabilities under Section 4999 of the Code.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective as of the date first above written.

PENN VIRGINIA CORPORATION

By:__
Name:__
Title:__

PARTICIPANT

__

Name:__
Date:__

PERFORMANCE RESTRICTED STOCK UNIT AWARD AGREEMENT

PENN VIRGINIA CORPORATION
2019 MANAGEMENT INCENTIVE PLAN

This Performance Restricted Stock Unit Award Agreement (this "Agreement") is made as of the __ day of _______, ___ (the "Grant Date") between Penn Virginia Corporation (the "Company"), and _____________ ("Participant"), and is made pursuant to the terms of the Penn Virginia Corporation 2019 Management Incentive Plan (as the same may be amended, the "Plan"). Any capitalized term used herein but not defined shall have the meaning set forth in the Plan.

Section 1. Grant of Restricted Stock Units. The Company hereby grants to Participant, subject to the terms and conditions set forth in this Agreement and the Plan, a target Restricted Stock Unit Award consisting of ______ restricted stock units ("Restricted Stock Units"), *provided* that, except as otherwise provided in this Agreement, the final number of Restricted Stock Units earned by the Participant (if any) shall be determined on the vesting date in accordance with the performance criteria set forth on Schedule I (the "Schedule"). As used in this Agreement, "Performance Period" shall refer to the Performance Period set forth on the Schedule. Subject to the terms and conditions set forth in this Agreement and the Plan, each Restricted Stock Unit represents the right to receive one share of Common Stock.

Section 2. Vesting of the Restricted Stock Units.

(a) Generally. On the last day of the Performance Period, the number of Restricted Stock Units that are earned (if any) for the Performance Period shall be based on the extent to which the Company has satisfied the performance conditions set forth on the Schedule, subject to Participant's continuous Service with the Company from the Grant Date through the last day of the Performance Period.

(b) Change in Control. Upon the occurrence of a Change in Control that involves a merger, reclassification, reorganization, or other similar transaction in which the surviving entity, the Company's successor or the direct or indirect parent of the surviving entity or the Company's successor, fails to assume this Restricted Stock Unit Award or substitute this Restricted Stock Unit Award with a substantially equivalent award, the Restricted Stock Units granted hereunder shall become earned and vest assuming that the Performance Period ended on the date of the Change in Control with performance assessed under the performance conditions set forth on the Schedule through the date of such Change in Control, subject to Participant's continuous Service with the Company from the Grant Date through the date of the Change of Control. Such earned and vested Restricted Stock Units shall be settled immediately prior to the consummation of, but contingent upon the occurrence of, the Change in Control.

Section 3. Termination of Service. Upon the occurrence of a termination of Participant's Service, the Restricted Stock Units shall be treated as set forth below.

(a) Death; Disability; Termination by the Company without Cause; Resignation for Good Reason. Upon the occurrence of a termination of Participant's Service as a result of death or Disability, by the Company or an Affiliate without Cause or by a resignation by the Participant for Good Reason, the continued service requirements that apply to the Restricted Stock Units granted hereunder shall cease to apply and a pro-rata number of Restricted Stock Units shall vest on the date of such termination of Service equal to (1) the number of Restricted Stock Units that would have otherwise been earned based on performance under the performance conditions set forth on the Schedule through the date of such termination of Service *multiplied by* (2) a fraction, the numerator of which is that number of days during the period commencing on the first day of the Performance Period and ending on the last day of employment, and the denominator of which is the total number of days in the Performance Period. Notwithstanding the foregoing, upon a termination of Participant's Service by the Company or an Affiliate without Cause or by a resignation by the Participant for Good Reason, in either case that occurs within twelve (12) months following a Change in Control, the continued service requirements that apply to the Restricted Stock Units granted hereunder shall cease to apply and a number of Restricted Stock Units shall vest on the date of such termination of Service equal to 100% of the number of Restricted Stock Units that would have otherwise been earned based on performance under the performance conditions set forth on the Schedule through the date of such termination of Service.

(b) Definitions. For purposes of this Agreement, the terms set forth below shall have the following respective meanings:

(i)"Disability" shall mean a disability that entitles the Participant to benefits under the Company's long-term disability plan, as may be in effect from time to time, as determined by the plan administrator of the long-term disability plan.

(ii)"Good Reason" has the meaning ascribed to such term in any employment agreement between the Participant and the Company or, if none, means the occurrence of any of the following events or conditions: (i) a material diminution in the Participant's title, authority, duties or responsibilities from those in effect on the Grant Date, (ii) a material reduction in the Participant's base salary or annual cash incentive compensation opportunity from that in effect on the Grant Date or (iii) the relocation of the Participant to a location more than fifty (50) miles from the location at which the Participant is based on the Grant Date; provided, however, that such event or condition remains uncured forty-five (45) days following Participant's delivery to the Company of written notice of the specific grounds for Good Reason, which notice is delivered within forty-five (45) days following the initial occurrence of the event or condition giving rise to Good Reason .

(c) Other Terminations of Service. Upon the occurrence of a termination of Participant's Service for any reason other than as provided in Section 2 or Section 3(a), all unvested Restricted Stock Units shall be immediately forfeited and cancelled and Participant shall not be entitled to any compensation or other amount with respect thereto.

Section 4. Settlement. Any Restricted Stock Units that become vested and non-forfeitable pursuant to Section 2 or Section 3 ("Vested RSUs") shall be settled as set forth in Section 2(b) (if applicable), or as soon as administratively practicable following the vesting date, but in no event later than March 15th of the year following the year in which such vesting date occurs (if Section 2(b) is not applicable). Vested RSUs will be settled, unless otherwise determined by the Committee, by the Company through the delivery to the Participant of a number of shares of Common Stock equal to the number of Vested RSUs.

No fractional shares of Common Stock shall be issued. Any fractional earned Restricted Stock Units will be rounded down to the next whole number.

Section 5. Restrictions on Transfer. Except as permitted under Section 11 of the Plan, no Restricted Stock Units may be transferred, pledged, assigned, hypothecated or otherwise disposed of in any way by Participant, except by will or by the laws of descent and distribution. In the event that Participant becomes legally incapacitated, Participant's rights with respect to the Restricted Stock Units shall be exercisable by Participant's legal guardian or legal representative. The Restricted Stock Units shall not be subject to execution, attachment or similar process. Any attempted assignment, transfer, pledge, hypothecation or other disposition of the Restricted Stock Units contrary to the provisions hereof, and the levy of any execution, attachment or similar process upon any Restricted Stock Units, shall be null and void and without effect.

Section 6. Investment Representation. Upon any acquisition of the shares of Common Stock underlying the Restricted Stock Units at a time when there is not in effect a registration statement under the Securities Act relating to the shares of Common Stock, Participant hereby represents and warrants, and by virtue of such acquisition shall be deemed to represent and warrant, to the Company that such shares of Common Stock shall be acquired for investment and not with a view to the distribution thereof, and not with any present intention of distributing the same, and Participant shall provide the Company with such further representations and warranties as the Company may reasonably require in order to ensure compliance with applicable federal and state securities, blue sky and other laws. No shares of Common Stock underlying the Restricted Stock Units shall be acquired unless and until the Company and/or Participant have complied with all applicable federal or state registration, listing and/or qualification requirements and all other requirements of law or of any regulatory agencies having jurisdiction, unless the Committee reasonably determines that Participant may acquire such shares of Common Stock pursuant to an exemption from registration under the applicable securities laws.

Section 7. Adjustments. The Restricted Stock Units granted hereunder shall be subject to the provisions of Section 4.2 of the Plan.

Section 8. No Right of Continued Service. Nothing in the Plan or this Agreement shall confer upon Participant any right to continued Service with the Company or any Affiliate.

Section 9. Limitation of Rights; Dividend Equivalents. Participant shall not have any privileges of a stockholder of the Company with respect to any Restricted Stock Units, including, without limitation, any right to vote any shares of Common Stock underlying such Restricted Stock Units or to receive dividends or other distributions or payments of any kind in respect thereof or exercise any other right of a holder of any such securities, unless and until there is a date of settlement and issuance to Participant of the underlying shares of Common Stock. Notwithstanding the foregoing, the Restricted Stock Unit Award granted hereunder is hereby granted in tandem with corresponding dividend equivalents with respect to each share of Common Stock underlying the Restricted Stock Unit Award granted hereunder (each, a "Dividend Equivalent"), which Dividend Equivalent shall remain outstanding from the Grant Date until the earlier of the settlement or forfeiture of the Restricted Stock Unit to which it corresponds. Participant shall be entitled to accrue payments equal to dividends declared, if any, on the Common Stock underlying the Restricted Stock Unit to which such Dividend Equivalent relates, payable in cash and subject to the vesting of the Restricted Stock Unit to which it relates, at the time the Common Stock underlying the Restricted Stock Unit is settled and delivered to Participant pursuant to Section 4; provided, however, if any dividends or distributions are paid in shares of Common Stock, the shares of Common Stock shall be deposited with the Company, shall be deemed to be part of the Dividend Equivalent, and shall be subject to the same vesting requirements, restrictions on transferability and forfeitability as the Restricted Stock Units to which they correspond. Dividend Equivalents shall not entitle Participant to any payments relating to dividends declared after the earlier to occur of the settlement or forfeiture of the Restricted Stock Units underlying such Dividend Equivalents.

Section 10. Construction. The Restricted Stock Unit Award granted hereunder is granted pursuant to the Plan and is in all respects subject to the terms and conditions of the Plan. Participant hereby acknowledges that a copy of the Plan has been delivered to Participant and accepts the Restricted Stock Unit Award hereunder subject to all terms and provisions of the Plan, which are incorporated herein by reference. In the event of a conflict or ambiguity between any term or provision contained herein and a term or provision of the Plan, the Plan will govern and prevail. The construction of and decisions under the Plan and this Agreement are vested in the Board, whose determinations shall be final, conclusive and binding upon Participant.

Section 11. Notices. Any notice hereunder by Participant shall be given to the Company in writing and such notice shall be deemed duly given only upon receipt thereof by the General Counsel of the Company at the Company's principal executive offices. Any notice hereunder by the Company shall be given to Participant in writing at the most recent address as Participant may have on file with the Company.

Section 12. Governing Law. This Agreement shall be construed and enforced in accordance with, the laws of the Commonwealth of Virginia, without giving effect to the choice of law principles thereof.

Section 13. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed to be an original but all of which together shall constitute one and the same instrument.

Section 14. **Binding Effect.** This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators, successors and assigns.

Section 15. **Section 409A.** This Agreement is intended to comply with Section 409A of the Code ("Section 409A") or an exemption thereunder and shall be construed and administered in accordance with Section 409A. Notwithstanding any other provision of the Plan or this Agreement, payments provided under this Agreement may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any payments under this Agreement that may be excluded from Section 409A shall be excluded from Section 409A to the maximum extent possible. The Restricted Stock Units granted hereunder shall be subject to the provisions of Section 13.3 of the Plan. Notwithstanding the foregoing, the Company makes no representations that the payments and benefits provided under this Agreement comply with Section 409A, and in no event shall the Company or any of its Subsidiaries or Affiliates be liable for all or any portion of any taxes, penalties, interest or other expenses that may be incurred by Participant on account of non-compliance with Section 409A or otherwise.

Section 16. **Entire Agreement.** Participant acknowledges and agrees that this Agreement and the Plan constitute the entire agreement between the parties with respect to the subject matter hereof and thereof, superseding any and all prior agreements whether verbal or otherwise, between the parties with respect to such subject matter. Except as otherwise expressly set forth herein, the terms and conditions of the Restricted Stock Units will not be governed or affected by the terms of Participant's employment agreement or offer letter, or any severance, change of control or similar agreement or policy of the Company or any Affiliate to which Participant may be party or by which he or she may be covered.

Section 17. **Clawback.** The Restricted Stock Unit Award will be subject to recoupment in accordance with any clawback or recoupment policy of the Company, including without limitation, any clawback or recoupment policy that the Company is required to adopt pursuant to the listing standards of any national securities exchange or association on which the Company's securities are listed or as is otherwise required by the Dodd-Frank Wall Street Reform and Consumer Protection Act or other applicable law.

Section 18. **Tax Withholding**. This Agreement and the Restricted Stock Units shall be subject to withholding in accordance with Section 13.4 of the Plan, including the net settlement provision therein, Section 13.4(c).

Section 19. **Certain Excise Taxes**. Notwithstanding anything to the contrary in this Agreement, if Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code), and the payments provided for under this Agreement, together with any other payments and benefits which Participant has the right to receive from the Company or any of its Affiliates, would constitute a "parachute payment" (as defined in Section 280G(b)(2) of the Code), then the payments provided for under this Agreement shall be either (a) reduced (but not below zero) so that the present value of such total amounts and benefits received by Participant from the Company and its Affiliates will be one dollar ($1.00) less than three times Participant's "base amount"(as defined in Section 280G(b)(3) of the Code) and so that no portion of such amounts and benefits received by Participant shall be subject to the excise tax imposed by Section 4999 of the Code or (b) paid in full, whichever produces the better net after-tax position to Participant (taking into account any applicable excise tax under Section 4999 of the Code and any other applicable taxes). The determination as to whether any such reduction in the amount of the payments provided hereunder is necessary shall be made by the Company in good faith. If a reduced payment is made or provided and through error or otherwise that payment, when aggregated with other payments and benefits from the Company (or its Affiliates) used in determining if a parachute payment exists, exceeds one dollar ($1.00) less than three times Participant's base amount, then Participant shall immediately repay such excess to the Company upon notification that an overpayment has been made. Nothing in this Agreement shall require the Company (or any of its Affiliates) to be responsible for, or have any liability or obligation with respect to, Participant's excise tax liabilities under Section 4999 of the Code.

(SIGNATURES ON FOLLOWING PAGE)

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective as of the date first above written.

PENN VIRGINIA CORPORATION

By:__
Name: John A. Brooks
Title: President and CEO

PARTICIPANT

__

Name:__
Date:__

Schedule I

Performance Conditions

The number of Restricted Stock Units that vest pursuant to Section 2(a) of the Agreement and this Schedule I shall be determined by the Company's relative Total Shareholder Return (defined below) rank among a group of Peer Companies (described below) during the 3-year period commencing ____________ and ending ________________ (the "Performance Period"). Such Vested RSUs, if any, will be settled in accordance with Section 4 of the Agreement.

At the end of the Performance Period, the Peer Companies and the Company shall be ranked together based on their respective TSRs for the Performance Period with the highest TSR being number 1 and the lowest TSR being the total number of Peer Companies. Based on the Company's relative TSR rank among the Peer Companies, expressed as a percentile ranking, for the First Performance Period, the number of Restricted Stock Units that vest will be determined by the Company's percentile rank as follows:

Company's Percentile Ranking	Percentage of Target Units that will become Vested Units
Below 30^{th}	0%
30^{th}	50%
50^{th}	100%
90^{th} or above	200%

If the Company is ranked between any of these payout levels, the percentage multiple of the Restricted Stock Units will be interpolated based on the actual percentile ranking of the Company (rounded to the nearest whole percentile) in relation to the payout levels. Notwithstanding the foregoing, in the event the Company's TSR for the Performance Period is negative, then the number Restricted Stock Units that would otherwise vest and become earned pursuant to the foregoing shall be divided by two. For example, if 200% of the Restricted Stock Units would have vested because the Company's TSR for the Performance Period was in the 95^{th} percentile, but that TSR was negative for the Performance Period, only 100% of the Restricted Stock Units will vest. Any fractional earned Restricted Stock Units will be rounded down to the next whole number.

"Total Stockholder Return" or "TSR" for the Company and each of the Peer Companies for each Performance Period is calculated pursuant to the formula $(x + y)/z$, where (x) is the difference between (i) the entity's average volume weighted closing common stock price for the last month of the Performance Period minus (ii) the entity's average volume weighted closing common stock price for the first month of the Performance Period, (y) represents all dividends paid by the entity in respect of the entity's common stock during the Performance Period, and (z) is the entity's average volume weighted closing common stock price for the first month of the Performance Period.

Calculation of TSRs shall be adjusted to take into account any stock splits, stock dividends, reorganizations, or similar events that may affect the common stock prices of the Company or any of the Peer Companies.

The Peer Companies used for purposes of calculating relative TSR shall be the following companies:

[ ]

In the event that any of the Peer Companies ceases to be publicly traded during the applicable Performance Period, it shall be removed from the list of Peer Companies and shall be excluded completely when determining the Company's relative TSR for the Performance Period. In the event that any of the Peer Companies files for bankruptcy pursuant to the U.S. Bankruptcy Code during the Performance Period, it shall be given a TSR of -100% when determining the Company's relative TSR for the Performance Period.

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

We have issued our reports dated February 28, 2020, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Penn Virginia Corporation on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said reports in the Registration Statements of Penn Virginia Corporation on Forms S-3 (File No. 333-214709 and File No. 333-216756) and Forms S-8 (File No. 333-213979 and File No. 333-233364).

/s/ GRANT THORNTON LLP

Houston, Texas
February 28, 2020

Exhibit 23.2

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

February 28, 2020

Penn Virginia Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our report entitled "Report as of December 31, 2019 on Reserves and Revenue of Certain Properties with interests attributable to 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, 2019 (the Annual Report), to be filed with the United States Securities and Exchange Commission on or about February 28, 2020. In addition, we hereby consent to the incorporation by reference of our report of third party dated February 19, 2020, 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-3 (File Nos. 333-214709 and 333-216756) and Form S-8 (File Nos. 333-213979 and 333-233364).

Very truly yours,

/s/DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON

Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, John A. Brooks, Chief Executive Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: February 28, 2020

/s/ JOHN A. BROOKS

John A. Brooks
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Russell T Kelley, Jr., Senior Vice President and Chief Financial Officer of Penn Virginia Corporation (the “Registrant”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Registrant (this “Report”);

2. Based on my knowledge, this Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Report;

3. Based on my knowledge, the financial statements, and other financial information included in this Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Report;

4. The Registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and we have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the Registrant’s disclosure controls and procedures and presented in this Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Report based on such evaluation; and

(d) Disclosed in this Report any change in the Registrant’s internal control over financial reporting that occurred during the Registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Registrant’s internal control over financial reporting; and

5. The Registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant’s auditors and the audit committee of the Registrant’s board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant’s internal control over financial reporting.

Date: February 28, 2020

/s/ RUSSELL T KELLEY, JR

Russell T Kelley, Jr.
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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John A. Brooks, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2020

/s/ JOHN A. BROOKS

John A. Brooks
Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Penn Virginia Corporation (the "Company") on Form 10-K for the year ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Russell T Kelley, Jr., Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 28, 2020

/s/ RUSSELL T KELLEY, JR.

Russell T Kelley, Jr.

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 19, 2020

Penn Virginia Corporation
16285 Park Ten Place
Suite 500
Houston, Texas 77084

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2019, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Penn Virginia Corporation (Penn Virginia) has represented it holds an interest. This evaluation was completed on February 19, 2020. The properties evaluated herein consist of working and royalty interests located in Texas. Penn Virginia has represented that these properties account for 100 percent on a net equivalent barrel basis of Penn Virginia' net proved reserves as of December 31, 2019. The net proved reserves estimates 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, 2019. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Penn Virginia after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as 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 production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Penn Virginia to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Penn Virginia, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount 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.

Estimates of reserves and revenue should be regarded only as estimates that may change as production history and additional information become available. Not only are such 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.

Information used in the preparation of this report was obtained from Penn Virginia and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Penn Virginia with respect to the property interests being evaluated, 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.

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.

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 the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC and 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 (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. 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 analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Penn Virginia.

Penn Virginia has represented that its senior management is committed to the development plan provided by Penn Virginia and that Penn Virginia has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Penn Virginia from wells drilled through December 31, 2019, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through June 2019. Estimated cumulative production, as of December 31, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 6 months.

Oil and condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

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 estimated herein are reported as sales gas. All gas reserves are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas reserves included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Penn Virginia, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Penn Virginia.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Penn Virginia. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

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 agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Penn Virginia to the reference price of $55.67 per barrel and held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $58.26 per barrel of oil and condensate and $13.36 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 agreements. The gas prices were calculated for each property using differentials furnished by Penn Virginia to the reference price of $2.578 per million Btu and held constant thereafter. Btu factors provided by Penn Virginia were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.683 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates Texas. 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 2019 values, provided by Penn Virginia, and were not adjusted for inflation. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Penn Virginia for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

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, NGL, 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 FASB 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 SEC; 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.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2019, of the properties evaluated herein 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, 2019			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	40,641	8,846	41,808	56,455
Proved Undeveloped	58,255	10,308	48,641	76,670
Total Proved	**98,896**	**19,154**	**90,449**	**133,125**

Note: Sales gas reserves estimated herein were 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 to be derived from the production and sale of the net proved reserves, as of December 31, 2019, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	**Total Proved (M$)**
Future Gross Revenue	2,598,167	6,260,292
Production and Ad Valorem Taxes	165,748	397,759
Operating Expenses	719,807	1,395,132
Capital and Abandonment Costs	28,744	1,174,215
Future Net Revenue	1,683,868	3,293,186
Present Worth at 10 Percent	1,012,020	1,600,096

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 reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2019, estimated reserves.

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 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,

/s/ DeGOLYER and MacNAUGHTON

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

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 firm did prepare the report of third party addressed to Penn Virginia dated
2. February 19, 2020, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

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 Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 35 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