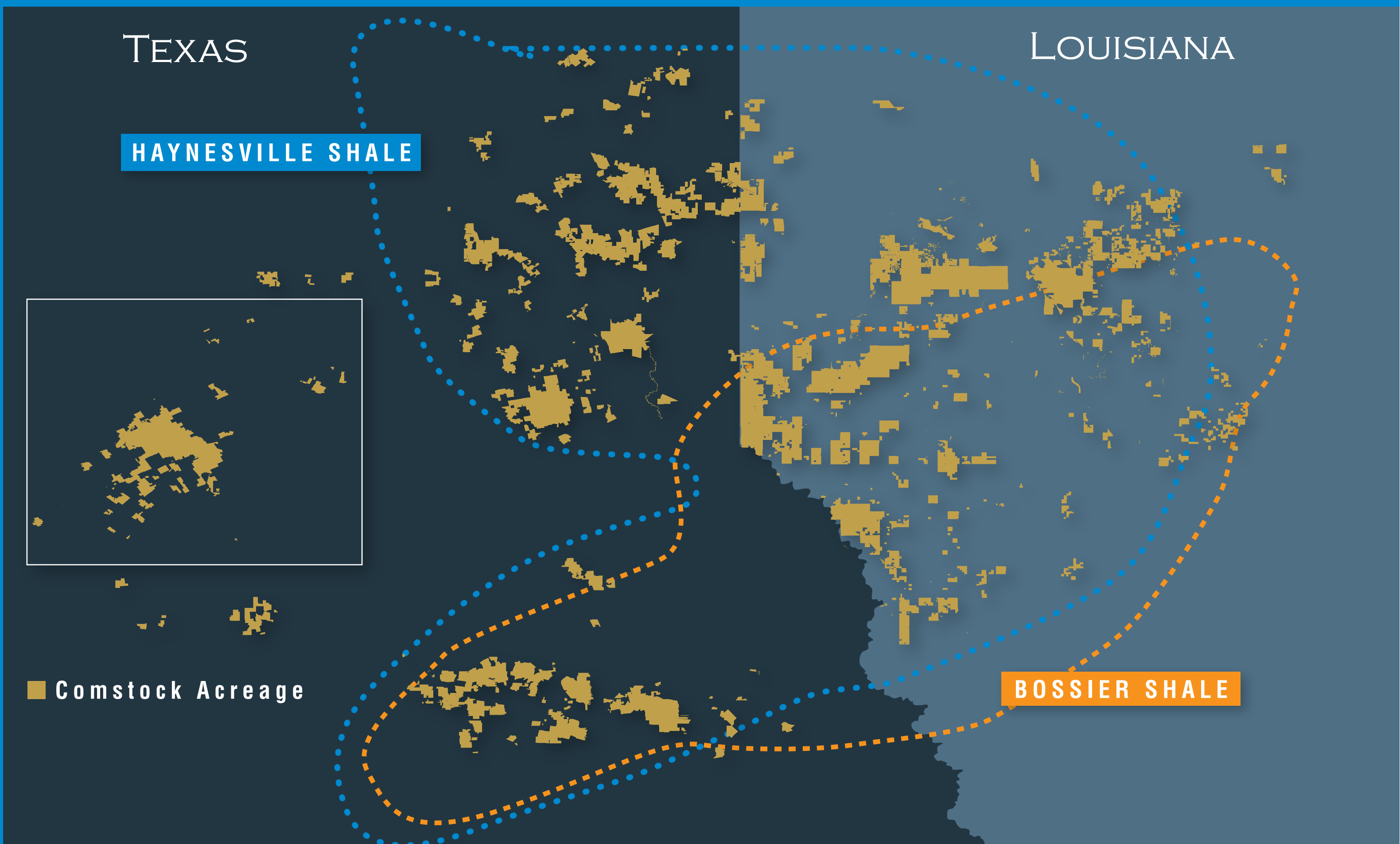
CRK 2019

Comstock Resources

ANNUAL REPORT

HAYNESVILLE / BOSSIER SHALE



Net Acres (Haynesville/Bossier)	309,000
Net Drilling Locations	1,983
% Held-by-Production	95%
% Operated	91%
% Working Interest	76%
Q4 19 Production	1.4 Bcfe/d
Proved Reserves	5,442 Bcfe
% Gas	98%
PDP PV-10	$2.1 bn
Total PV-10	$3.3 bn

Comstock Resources, Inc. is a growing independent energy company engaged in the acquisition, development, production and exploration of oil and natural gas properties. Our operations are primarily focused in Texas, Louisiana and North Dakota.

TO OUR STOCKHOLDERS:

We had another transformative year in 2019. We completed the largest acquisition in our corporate history, which more than doubled our size. We became the largest producer of natural gas in the Haynesville shale and in the state of Louisiana as a result of this acquisition.

ACQUIRED COVEY PARK ENERGY FOR $2.2 BILLION

In July 2019, we completed the acquisition of Covey Park Energy LLC for total consideration of $2.2 billion. This acquisition made us the basin leader in the Haynesville shale, which is North America's premier natural gas basin because of its superior economics and geographic proximity to the Gulf Coast. Our major stockholder, Jerry Jones, invested an additional $475 million in the Company to facilitate the acquisition. Covey Park had 249,000 net acres in the Haynesville/Bossier shale with approximately 1,200 net future drilling locations. The Covey Park acquisition increased our production by more than 700 MMcfe/day and added 2.9 Tcfe to our proved SEC reserves.

SUCCESSFULLY INTEGRATED COVEY PARK OPERATIONS

Covey Park Energy LLC was larger than Comstock at the time of the merger. Despite the significant size, we were able to successfully integrate Covey Park operations in less than six months. We also were able to meet and exceed the goals that were set for the acquisition, including reducing combined general and administrative expenses from $61 million to $30 million. In addition, we lowered drilling and completion costs and the gathering and transportation costs of the combined companies. With the merger, we reconstituted our senior management team and brought over four Covey Park Vice Presidents. When combining

the staffs of the two companies, we selected department leaders by objectively looking at the best person available. We also selected the best practices from each company and were focused on creating an efficient / low overhead company.

ACHIEVED INDUSTRY LEADING LOW OPERATING COST STRUCTURE

The additional size and scale we gained from the Covey Park acquisition allowed us to achieve the industry leading low

operating cost structure following the merger. Our general and administrative costs, excluding stock-based compensation, averaged only 4¢ per Mcfe produced in the fourth quarter of 2019, the first full quarter to include the Covey Park operations. This amount is substantially less than any of our competitors. Our gathering and transportation costs averaged 24¢ per Mcfe in the fourth quarter, which is substantially lower than any other significant natural gas producer. Our remaining operating costs, including production taxes and other lifting costs, averaged 31¢ per Mcfe, reflecting the low cost nature of our Haynesville operations.

GENERATED STRONG RESULTS FROM 2019 DRILLING PROGRAM

We had another strong year with the drill bit. Comstock and Covey Park, on a combined basis have drilled 217 horizontal Haynesville/ Bossier wells since 2015, more than any other operator in the play. Under our 2019 Haynesville/ Bossier shale drilling program, we drilled 64 (46.5 net to us) successful operated wells, which had an average per well initial production rate of 25 MMcf per day. The drilling activities allowed us to grow pro forma production by 37% in 2019.

COMPLETED VALUE ADDED BOLT-ON HAYNESVILLE SHALE ACQUISITION

In November 2019, we completed a bolt-on Haynesville acquisition by issuing 4.5 million shares of common stock in exchange for a private company. The acquisition added 3,155 net acres with 44 (12.7 net to us) undrilled locations and 76 Bcfe of proved oil and gas reserves.

GREW PROVED RESERVE BASE AT LOW FINDING COSTS OF 72¢ PER MCFE

The combination of the acquisitions and the successful drilling program allowed us to grow our proved oil and natural gas reserves in 2019 by 125% to 5.4 trillion cubic feet of natural gas equivalent. The PV 10 Value of our proved reserves grew by 85% to $3.3 billion. The growth in proved reserves from the acquisitions and the drilling program was achieved at low finding costs of 72¢ per Mcfe, excluding price-related revisions to reserves.

DELIVERED STRONG FINANCIAL RESULTS

The Jerry Jones contribution in 2018, the excellent results from our Haynesville drilling program and the acquisition of Covey Park all combined to deliver strong financial results in 2019. We reported net income available to common stockholders of $74.5 million or 52¢ per diluted share for 2019. Excluding certain items not related to normal operating activities primarily due to the closing of the Covey Park acquisition, our net income was $122.3 million or 77¢ per diluted share.

We produced 292.8 Bcf of natural gas and 2.7 million barrels of oil in 2019. Our natural gas production increased by 192% and oil production was 61% higher. Natural gas production averaged 802 MMcf per day and oil production averaged 7,356 barrels per day in 2019. On a pro forma basis, assuming the Covey Park acquisition had been completed on January 1, 2019, natural gas and oil production would have been 1,190 MMcf per day and 7,416 barrels per day, respectively. Our realized natural gas price, after hedging, decreased by 18% to $2.35 per Mcf and our oil price, after hedging, of $49.64 per barrel decreased by 16% from 2018. Oil and gas sales (including hedging) increased 112% to $821 million and EBITDAX grew 114% to $614 million. Adjusted operating cash flow (excluding working capital changes) increased 124% to $468 million. With the higher production, our lifting costs increased 137% to $188 million and our depreciation, depletion and amortization expense increased by 127% to $277 million.

2020 OUTLOOK

With the significant decline in oil and natural gas prices in late 2019 and early 2020, we are primarily focused on free cash flow generation and managing the Company through the current low price environment. Our Haynesville drilling program generates economic returns even with low natural gas prices. We have cut back the number of wells that we plan to drill in 2020 in order to generate free cash flow that we will use to pay down our debt and strengthen our balance sheet. The strength we have is our industry leading low cost structure and well economics. We still expect 6%-8% pro forma production growth in 2020 even with the reduced activity. We have prioritized free cash flow goals in 2020 over production growth, but have maintained adequate investment to keep our production flat on a longer term basis. We have hedged almost half of our production in 2020 and entered the year with adequate liquidity of $269 million.

The directors and management of Comstock want to thank the stockholders for their continued support.

M. Jay Allison

M. Jay Allison
Chairman and
Chief Executive Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ **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 No. 001-03262

COMSTOCK RESOURCES, INC.
(Exact name of registrant as specified in its charter)

NEVADA	**94-1667468**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(Address of principal executive offices including zip code)

(972) 668-8800
(Registrant's telephone number and area code)

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

Title of each class	*Trading Symbol(s)*	*Name of each exchange on which registered*
Common Stock, par value $0.50 (per share)	**CRK**	**New York Stock Exchange**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the 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 an 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.

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

Emerging growth company ☐

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 28, 2019 (the last business day of the registrant's most recently completed second fiscal quarter), was $83.2 million.

As of March 1, 2020, there were 190,004,776 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2020 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2019

CONTENTS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified by their use of terms such as “expect,” “estimate,” “anticipate,” “project,” “plan,” “intend,” “believe” and similar terms. All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” regarding:

- amount and timing of future production of oil and natural gas;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- the availability of exploration and development opportunities;
- our financial or operating results;
- our cash flow and anticipated liquidity;
- operating costs including lease operating expenses, administrative costs and other expenses;
- finding and development costs;
- our business strategy; and
- other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

- the risks described in “Risk Factors” and elsewhere in this report;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the timing and success of our drilling activities;
- the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
- our ability to effectively market our oil and natural gas;
- the availability of rigs, equipment, supplies and personnel;
- our ability to discover or acquire additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- general economic conditions, status of the financial markets and competitive conditions; and
- our ability to retain key members of our senior management and key employees.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us", "our", "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of U.S. 42 gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"BOE" means one barrel of oil equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means 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" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" means a well drilled to find a new field or to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"LNG" refers to liquefied natural gas, which is a composition of methane and some mixture of ethane that has been cooled to liquid form for ease and safety of non-pressurized storage or transport.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means one thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMBOE" means one million barrels of oil equivalent.

"MMBtu" means one million British thermal units.

"MMcf" means one million cubic feet of natural gas.

"MMcf/d" means one million cubic feet of natural gas per day.

"MMcfe/d" means one million cubic feet of natural gas equivalent per day.

"MMcfe" means one million cubic feet of natural gas equivalent.

"Net" when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

"Net production" means production we own less royalties and production due others.

"NGL" refers to natural gas liquids, which is composed exclusively of carbon and hydrogen.

"Oil" means crude oil or condensate.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved developed non-producing" means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

"Proved developed producing" means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category includes recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

"Proved reserves" means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements.

"Proved undeveloped reserves" means 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 drilling locations offsetting productive wells that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

"PV 10 Value" means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. This amount is the same as the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves except that it is determined without deducting future income taxes. Although PV 10 Value is not a financial measure calculated in accordance with

GAAP, management believes that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Because many factors that are unique to any given company affect the amount of estimated future income taxes, we believe the use of a pre-tax measure is helpful to investors when comparing companies in our industry.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Royalty" means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"SEC" means the United States Securities and Exchange Commission.

"Tcf" means one trillion cubic feet of natural gas.

"Tcfe" means one trillion cubic feet of natural gas equivalent.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

ITEMS 1 and 2. *BUSINESS AND PROPERTIES*

We are an independent energy company operating primarily in the Haynesville shale, a premier natural gas basin located in East Texas and North Louisiana with superior economics and geographical proximity to the Gulf Coast markets. As of December 31, 2019, 93% of our proved reserves were in the Haynesville and Bossier shale play and we are the largest producer of natural gas in that basin. We are focused on creating value through the development of our substantial inventory of highly economic and low-risk drilling opportunities in the Haynesville and Bossier shales. Our common stock is listed and traded on the New York Stock Exchange under the symbol "CRK".

On August 14, 2018, Arkoma Drilling, L.P. and Williston Drilling, L.P. (collectively, the "Jones Partnerships") contributed certain oil and gas properties in North Dakota and Montana in exchange for 88,571,429 newly issued shares of our common stock representing 84% of our then outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group"). References to "Successor" or "Successor Company" relate to the operations of us and our subsidiaries (the "Company") subsequent to the Jones Contribution on August 13, 2018. Reference to "Predecessor" or "Predecessor Company" relate to the operations of the Company on or prior to August 13, 2018.

On July 16, 2019, we acquired Covey Park Energy LLC ("Covey Park") in a cash and stock transaction valued at approximately $2.2 billion (the "Covey Park Acquisition"). Covey Park was a privately held Haynesville shale focused company producing approximately 710 MMcfe per day. The Covey Park Acquisition meaningfully increased our scale, more than doubling our asset base and created significant financial and operational efficiencies.

Our oil and gas operations are primarily concentrated in Louisiana, Texas and North Dakota. Our oil and natural gas properties are estimated to have proved reserves of 5.4 Tcfe with an SEC PV 10 Value of $3.3 billion as of December 31, 2019. Our proved oil and natural gas reserve base is 98% natural gas and 2% oil and was 36% developed as of December 31, 2019, and our properties have an average reserve life of approximately 18 years.

Our proved reserves at December 31, 2019 and our average daily production for the three months ended December 31, 2019 are summarized below. We are presenting the three months ended December 31, 2019 production as it represents our first full quarter that includes the Covey Park Acquisition:

	Proved Reserves at December 31, 2019			Production Three Months Ended December 31, 2019		
	Oil (MMBbls)	Natural Gas (Bcf)(1)	Total (Bcfe)(1)	Oil (MBbls/d)	Natural Gas (MMcf/d)(1)	Total (MMcfe/d)(1)
Haynesville/Bossier Shale	—	5,068.2	5,068.8	0.1	1,253.6	1,253.8
Bakken Shale	14.7	48.5	136.9	5.2	16.6	47.8
Other	2.0	224.8	236.3	1.0	50.7	56.9
Total	16.7	5,341.5	5,442.0	6.3	1,320.9	1,358.5

(1) Natural gas volumes include NGLs. Oil and NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of oil or NGLs for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

Strengths

High Quality Properties. As of December 31, 2019, we have accumulated 389,247 acres (308,664 net to us) in the Haynesville and Bossier shale plays, located in the North Louisiana and Texas.

Approximately 95% of our Haynesville/Bossier shale net acreage is held-by-production and our Haynesville/Bossier shale properties have extensive development and exploration potential. Advances in drilling and completion technology have allowed us to increase the reserves recovered through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns, we have focused our development activities primarily on drilling Haynesville and Bossier horizontal wells in recent years.

Our Haynesville and Bossier shale positions in North Louisiana and East Texas are located in one of the premier North American natural gas shale plays and have access to the Gulf Coast market demand related to LNG exports and the petrochemical industry due to its geographic proximity. We believe we are well positioned for future growth due to the following:

- *De-risked, contiguous and prolific oil and natural gas resources*. The Haynesville and Bossier shale plays have been substantially delineated since 2008 through the drilling of over 4,100 horizontal wells. We believe that these shale plays represent some of the most consistent and prolific natural gas development drilling opportunities in North America.

- *Management and operating team with extensive experience in developing the Haynesville and Bossier shale plays*. We were among the first exploration and production companies to effectively apply horizontal drilling techniques in the Haynesville and Bossier shales beginning in 2007. Since then, our management and operating team initiated a drilling program in the Haynesville and Bossier shales in 2015 based on a new, enhanced completion well design that significantly improved the economics of these wells in comparison to the 189 wells we drilled from 2008 to 2013. When combining our historical activity with Covey Park, we have drilled 217 (171.6 net to us) operated wells between 2015 and 2019, more wells than any other operator targeting the Haynesville or Bossier shale. These wells had an average per well initial production rate of 23 MMcf per day.

- *Attractive economic returns*. The Haynesville and Bossier shales offer highly economic and low-risk drilling opportunities through application of advanced drilling and completion technologies, including the use of longer laterals, and high intensity fracture stimulation using tighter frac stages and higher proppant loading. Our management and operating team has been instrumental in developing and optimizing some of the most effective completion techniques in the Haynesville and Bossier shales and such completion techniques have resulted in a material improvement in initial production rates and recoverable reserves, which has resulted in some of the highest single well rates of return when compared to results from other natural gas basins in North America.

- *Proximity to premium natural gas markets*. Our natural gas production benefits from the strong regional Gulf Coast demand growth driven by a substantial increase in LNG exports, exports to Mexico and new or expanded petrochemical facilities. Producers, such as us, with access to the Gulf Coast natural gas markets are receiving higher net realized prices than most producers in other regions. We are also able to realize higher margins due to our ability to access the extensive midstream infrastructure at attractive rates and lack of above-market midstream commitments.

Value-Added Acquisitions. We closed the Covey Park Acquisition in July 2019 for $2.2 billion. The acquisition included approximately 249,000 net acres and 2.9 Tcfe of proved reserves. The Covey Park Acquisition added over 710 MMcfe per day of production and approximately 1,200 future drilling locations. In November 2019, we acquired a private company for $42.3 million in an all-stock transaction, which included approximately 3,155 net acres, 75 (20.1 net to us) producing wells and 44 (12.7 net to us) Haynesville/Bossier shale future drilling locations.

Successful Drilling Program. We spent $510.5 million on development activities in 2019, with $485.4 million on development activity in the Haynesville and Bossier shale. We spent $468.5 million on drilling and completing horizontal Haynesville and Bossier shale wells and an additional $16.9 million on other development activity. We drilled 82 (51.1 net) horizontal Haynesville and Bossier wells in 2019, which had an average lateral length of approximately 8,100 feet. We also completed 19 (7.3 net) wells that were drilled in 2018. Fifty (36.0 net) of the wells drilled in 2019 were also completed in 2019. We expect that the remaining 32 (15.1 net) wells will be completed in 2020. Our natural gas drilling program in 2019, combined with the Covey Park Acquisition was the major driver for the increase in our natural gas production of 192% over 2018 and contributed to the 132% growth we had in our natural gas reserves from 2018. We also incurred $25.1 million of development costs on our other properties, primarily on completing four (2.2 net to us) Eagle Ford shale wells.

Efficient Operator. We operated 92% of our proved reserve base as of December 31, 2019. As the operator, we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs, and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Business Strategy

Our strategy consists of the following principal elements:

- *Prudently grow cash flow, production and reserves through the development of our extensive drilling inventory in the Haynesville, Bossier and Eagle Ford shales.* We have an extensive inventory of horizontal well drilling locations prospective for the Haynesville and Bossier shales, providing us with years of inventory of development locations. The following outlines our Haynesville and Bossier shale future drilling locations by lateral length as we currently plan to drill them:

	Haynesville Shale					
	Operated		Non-Operated		Total	
Horizontal Lateral Length	(Gross)	(Net)	(Gross)	(Net)	(Gross)	(Net)
Less than 5,000 feet	373	289.2	660	85.9	1,033	375.1
5,000 feet to 8,000 feet	559	416.8	121	17.2	680	434.0
Greater than 8,000 feet	515	375.3	204	24.7	719	400.0
	1,447	1,081.3	985	127.8	2,432	1,209.1

	Bossier Shale					
	Operated		Non-Operated		Total	
Horizontal Lateral Length	(Gross)	(Net)	(Gross)	(Net)	(Gross)	(Net)
Less than 5,000 feet	212	156.5	312	33.8	524	190.3
5,000 feet to 8,000 feet	377	287.7	72	7.4	449	295.1
Greater than 8,000 feet	359	283.2	82	5.7	441	288.9
	948	727.4	466	46.9	1,414	774.3
Total	2,395	1,808.7	1,451	174.7	3,846	1,983.4

We have 21,482 (9,452 net to us) undeveloped acres prospective for development in the oil window of the Eagle Ford shale in South Texas. We have entered into a joint development venture with our acreage and have the opportunity to participate in the drilling of 225 (126.0 net to us) wells. During 2019, we participated in four (2.2 net) wells in the joint venture. Since much of our net acreage is held by production, we have the ability to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

We intend to manage the selection of drilling locations and the timing of development and associated capital expenditures in order to economically grow our cash flow, production and reserves while funding our capital expenditures with operating cash flow.

- *Enhance returns through a focus on optimizing full cycle economics*. We continually monitor and adjust our drilling program on a regular basis with the objective of achieving the most economical returns on our portfolio of drilling opportunities. We believe that we will achieve this objective by (i) minimizing our costs to drill and complete wells, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) producing near pipeline-quality natural gas, which leads to lower processing costs, and (iv) minimizing operating costs through efficient well management.

- *Evaluate and pursue strategic acquisition opportunities to grow our reserves, production, and acreage position.* We intend to leverage our management and operating team's significant technical expertise and experience in successfully executing and integrating acquisitions to continue pursuing acquisition opportunities that will add to our drilling inventory.

- *Maintain disciplined financial strategy.* We intend to maintain a conservative operating plan in 2020 targeting lower leverage and generating free cash flow.

- *Manage commodity price exposure through an active hedging program to protect our expected future cash flows.* We expect to maintain an active oil and natural gas price hedging program designed to mitigate volatility in oil and natural gas prices and to protect a portion of our expected future cash flows.

Primary Operating Areas

The following table summarizes the estimated proved oil and natural gas reserves as of December 31, 2019:

	Oil (MBbls)	Natural Gas (MMcf)(1)	Total (MMcfe)(1)	PV 10 Value (000's)(2)
Haynesville/Bossier Shale	86	5,068,248	5,068,765	$2,881,971
Bakken Shale	14,737	48,468	136,891	259,678
Other	1,924	224,781	236,328	110,186
Total	16,747	5,341,497	5,441,984	$3,251,835

(1) Natural gas volumes include NGLs. Oil and NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of oil or NGLs for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.
(2) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and gas reserves after income tax, discounted at 10%.

Haynesville/Bossier Shale

Approximately 93%, or 5.1 Tcfe of our proved reserves, are located in the Haynesville and Bossier shales in East Texas and North Louisiana, where we own interests in 1,104 producing wells (609.6 net to us). We operate 676 of these wells. The wells produce from the Bossier shale at depths of 10,500 to 12,100 feet and from the Haynesville shale at depths from 10,500 to 12,950 feet. Our production from the Haynesville and Bossier shale averaged 756 MMcfe of natural gas per day in 2019. We spent $468.5 million in 2019 drilling 82 wells (51.1 net to us) and completing 19 (7.3 net) wells that were drilled in 2018. We spent $9.3 million on other development activity in this region in 2019. We currently plan to spend approximately $421.0 million in 2020 to drill 46 (34.3 net to us) wells and to complete an additional 18 (12.6 net to us) wells we drilled in 2019.

Bakken Shale

Approximately 3% (23 MMBOE) of our proved reserves are located in North Dakota and Montana, where we own interests in 429 producing wells (66.8 net to us) which produce from the Bakken shale. The Bakken shale proved reserves are 65% oil and represent 8% of our PV 10 Value. We acquired 403 non-operated wells (60.3 net to us) in the Bakken shale with the Jones Contribution. Net daily production rates from our Bakken shale properties averaged 6,754 barrels of oil and 16.7 MMcf of natural gas per day in 2019.

Other Regions

Approximately 1.9 MMBOE of our proved reserves are located in South Texas that are prospective for production from the Eagle Ford shale. The Eagle Ford shale is found between 7,500 feet and 11,500 feet across our acreage position. We have 21,482 (9,452 net to us) undeveloped acres that are subject to a joint development agreement under which we have the opportunity to participate in up to 225 wells (126.0 net to us) in the future. During 2019, we participated in four (2.2 net to us) wells in the joint venture.

Approximately 39 Bcfe of our proved reserves, are located primarily in the Cotton Valley formations in East Texas and North Louisiana, where we own interests in 911 producing wells (598.4 net to us). These wells produce from multiple sands at a depth of 8,000 to 10,000 feet. We operate 645 of these wells. Our Cotton Valley wells averaged 11.4 MMcf of natural gas per day and 110 barrels of oil per day in 2019.

Our remaining proved reserves in other regions are located primarily in Texas, the Mid-Continent region and New Mexico. We own interests in 352 producing wells (133.8 net to us) within these regions. Net daily production from our other regions during 2019 totaled 17.9 MMcf of natural gas and 43 barrels of oil or 18 MMcfe per day.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves as of December 31, 2019:

	Oil (MBbls)	Natural Gas (MMcf)(1)	Total (MMcfe)(1)	PV 10 Value (000's)(2)
Proved Developed:				
Producing	15,076	1,858,063	1,948,521	$2,091,442
Non-producing	28	32,294	32,462	10,677
Total Proved Developed	15,104	1,890,357	1,980,983	2,102,119
Proved Undeveloped	1,643	3,451,140	3,461,001	1,149,716
Total Proved	16,747	5,341,497	5,441,984	3,251,835
Discounted Future Income Taxes				(338,624)
Standardized Measure of Discounted Cash Flows				$2,913,211

(1) Natural gas volumes include NGLs. Oil and NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of oil or NGLs for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

(2) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and gas reserves after income tax, discounted at 10%.

The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2017		2018		2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)[1]
Proved Developed	7,552	436,114	21,466	583,107	15,104	1,890,357
Proved Undeveloped	—	680,842	2,146	1,699,651	1,643	3,451,140
Total Proved Reserves	7,552	1,116,956	23,612	2,282,758	16,747	5,341,497

(1) Natural gas volumes include NGLs. NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of NGLs for six Mcf of natural gas based upon the approximate relative energy content.

Proved reserves that are attributable to existing producing wells are primarily determined using decline curve analysis and rate transient analysis, which incorporates the principles of hydrocarbon flow. Proved reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. Technologies relied on to establish reasonable certainty of economic producibility include electrical logs, radioactivity logs, core analyses, geologic maps and available production data, seismic data and well test data.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The average prices that we realized from sales of oil and natural gas and the associated lifting costs including severance and ad valorem taxes and transportation costs for each of the last three fiscal years were as follows:

	Predecessor		Successor	
	Years Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
Oil Price - $/Bbl	$49.02	$65.23	$57.34	$49.49
Natural Gas Price - $/Mcf	$ 2.84	$ 2.68	$ 3.20	$ 2.17
Lifting Costs - $/Mcfe	$ 0.77	$ 0.64	$ 0.79	$ 0.61

Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent the average first of the month prices received at the point of sale for the last twelve months. These prices have been adjusted from posted prices for both location and quality differences. The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2017	$48.71	$2.88
2018	$61.21	$2.90
2019	$55.69	$2.58

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In connection with estimating proved undeveloped reserves for our reserve report, reserves on undrilled acreage were limited to those that are reasonably certain of production when drilled where we can verify the continuity of the reservoir. We only include wells in our proved undeveloped reserves that we currently plan to drill and in which we have adequate capital resources to enable us to drill them. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir. We reflect changes to undeveloped reserves that occur in the same field as revisions to the extent that proved undeveloped locations are revised due to changes in future development plans, including changes to proposed lateral lengths, development spacing and timing of development.

As of December 31, 2019, our proved undeveloped reserves were comprised of 1.6 million barrels of oil and 3.5 Tcf of natural gas consisting of 592 undeveloped locations. We had proved undeveloped oil reserves of 1.2 million barrels associated with our Eagle Ford shale properties and 0.4 million barrels associated with our Bakken shale properties. Most of our natural gas undeveloped reserves are associated with our Haynesville and Bossier shale properties where our drilling program in 2019 was focused. Our natural gas proved undeveloped reserves increased by 1.7 Tcf during 2019. This increase was primarily related to the acquisitions including reserve additions associated with the Covey Park Acquisition of 1.9 Bcfe that were partially offset by 0.2 Bcfe of proved undeveloped conversions. During 2019, 34 proved undeveloped locations of the Haynesville shale wells were converted to proved developed. An additional four undeveloped oil locations were also converted.

As of December 31, 2018, our proved undeveloped reserves were comprised of 2.1 million barrels of oil and 1.7 Tcf of natural gas. We had proved undeveloped oil reserves of 1.6 million barrels associated with our Eagle Ford shale properties and 0.5 million barrels associated with our Bakken shale properties. Most of our natural gas undeveloped reserves are associated with our Haynesville and Bossier shale properties where our drilling program in 2018 was focused. Our natural gas proved undeveloped reserves increased by 1.0 Tcf during 2018. This increase was primarily related to the reserve additions and performance related revisions which were comprised of 952 Bcf of new undeveloped locations resulting from our successful Haynesville and Bossier shale drilling program and expanded future drilling plans and 64 Bcf of upward performance revisions attributable to our Haynesville and Bossier shale undeveloped reserves added in prior years. Acquisitions during 2018 added 204 Bcf of natural gas. The reserve additions were partially offset by 129 Bcf of reserves converted to developed reserves and the divestiture of 74 Bcf of natural gas reserves. Twenty-three of the Haynesville shale wells we drilled in 2018 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2018.

The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2017, 2018 and 2019:

	Proved Undeveloped Reserves					
	2017		2018		2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	—	550,941	—	680,842	2,146	1,699,651
Bakken Shale Contribution	—	—	502	1,061	—	—
Divestitures	—	(5,264)	(4,002)	(74,297)	—	(25,179)
Acquisitions	—	—	—	204,414	—	1,853,820
Extension & Discoveries	—	220,048	5,646	952,152	—	—
Conversion from Undeveloped to Developed	—	(103,506)	—	(128,692)	(247)	(188,894)
Revisions	—	18,623	—	64,171	(256)	111,742
Total Change	—	129,901	2,146	1,018,809	(503)	1,751,489
Ending Balance	—	680,842	2,146	1,699,651	1,643	3,451,140

The timing, by year, when our proved undeveloped reserve quantities are estimated to be converted to proved developed reserves is as follows:

	Proved Undeveloped Reserves					
	2017		2018		2019	
Year ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2018	—	166,801	—	—	—	—
2019	—	140,953	966	214,481	—	—
2020	—	156,568	147	385,209	58	363,900
2021	—	119,640	378	487,265	1,327	578,067
2022	—	96,880	190	368,696	122	795,598
2023	—	—	465	244,000	136	956,162
2024	—	—	—	—	—	757,413
Total	—	680,842	2,146	1,699,651	1,643	3,451,140

The following table presents the timing of our estimated future development capital costs to be incurred for the years ended December 31, 2017, 2018 and 2019:

	Future Development Costs Total Proved Undeveloped Reserves		
Year ended December 31,	2017	2018	2019
		(in millions)	
2018	$149.1	$ —	$ —
2019	123.7	193.4	—
2020	138.4	364.3	286.9
2021	116.2	516.9	566.6
2022	89.9	431.6	758.6
2023	—	276.4	918.7
2024	—	—	640.6
Total	$617.3	$1,782.6	$3,171.4

The following table presents the changes in our estimated future development costs for the years ended December 31, 2018 and 2019:

	(in millions)
Total as of December 31, 2017	$ 617.3
Development Costs Incurred	(103.1)
Asset Disposals	(124.8)
Jones Contribution	9.2
Asset Acquisitions	184.1
Additions and Revisions	1,199.9
Total Changes	1,165.3
Total as of December 31, 2018	1,782.6
Development Costs Incurred	(311.3)
Asset Disposals	(16.0)
Asset Acquisitions	1,573.7
Additions and Revisions	142.4
Total Changes	1,388.8
Total as of December 31, 2019	$3,171.4

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2019 of $3.2 billion increased by $1.4 billion from our estimated future capital costs of $1.8 billion as of December 31, 2018. This increase was primarily attributable to future development costs related to the proved undeveloped Haynesville and Bossier shale locations from the Covey Park Acquisition and another acquisition during 2019. As of December 31, 2019, our future capital costs include $3.1 billion to develop our Haynesville/Bossier shale properties and $70.4 million to develop our other properties.

We incurred approximately $103.1 million during 2018 in development costs related to proved undeveloped reserves. Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2018 of $1.8 billion increased by $1.2 billion from our estimated future capital costs of $0.6 billion as of December 31, 2017. This increase was primarily attributable to the inclusion of 216 additional proved undeveloped locations at December 31, 2018.

Proved reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We retained two independent petroleum consultants to conduct audits of our year-end 2019 reserve estimates. Netherland, Sewell & Associates, Inc. (“NSAI”) audited our Haynesville and Bossier shale properties and Lee Keeling and Associates, Inc. (“LKA”) audited our Bakken and Eagle Ford shale properties and other properties. The audited values of PV 10 Value was $2.9 billion by NSAI and $356.6 million by LKA, representing, in the aggregate, 100% of our total PV 10 Value as of December 31, 2019. The purpose of these audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates. These engineering firms were selected for their geographic expertise and their historical experience.

The summary reserve reports prepared by our independent petroleum consultants are included as an exhibit to this report. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The reserve auditor estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater than those of our auditor and some may be less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis. Actual variances for the year ended December 31, 2019 between our reserve estimates and the aggregate estimates of our independent petroleum consultants were less than 5%. During the year, our reserves group also performs separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

We have established, and maintain, internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations promulgated by the SEC. These internal controls include documented process workflows, employing qualified engineering and geological personnel, and on-going education for personnel involved in our reserves estimation process. Our internal audit function routinely tests our processes and controls. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultants to review properties and discuss methods and assumptions. We provide historical information to our consultants for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. Our consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Corporate Development. In some cases, additional meetings are held to review identified reserve differences.

All of our reserve estimates are reviewed with our executive management and ultimately approved by our Senior Vice President of Corporate Development, David J. Terry. Mr. Terry holds a Bachelor of Science degree in Petroleum Engineering from the Louisiana State University and has more than fifteen years of engineering experience in the oil and gas industry.

We did not provide estimates of total proved oil and natural gas reserves during the three year period ended December 31, 2019 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2019, we drilled development and exploratory wells as set forth in the table below:

	2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	—	—	4	2.2
Gas	30	15.7	49	17.0	82	51.1
Dry	—	—	—	—	—	—
	30	15.7	49	17.0	86	53.3
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	—	—	—	—	—	—
Total	30	15.7	49	17.0	86	53.3

In 2020 to the date of this report, we have drilled eight (5.5 net to us) operated wells and we have seven (5.1 net to us) operated wells currently in the process of being drilled.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2019:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Louisiana	14	3.6	1,187	593.9
Montana	1	0.2	—	—
New Mexico	1	—	88	13.6
North Dakota	428	66.6	—	—
Oklahoma	6	0.6	99	8.9
Texas	16	7.5	934	714.0
Wyoming	—	—	26	1.9
Total	466	78.5	2,334	1,332.3

We operate 1,430 of the 2,800 producing wells presented in the above table. As of December 31, 2019, we did not own an interest in any wells containing multiple completions, which means that a well is producing from more than one completed zone.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2019, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	216,718	156,089	29,735	21,230
New Mexico	12,757	2,739	—	—
Oklahoma	26,080	3,382	—	—
Texas	179,367	134,427	99,525	63,914
Wyoming	13,440	927	—	—
Total	448,362	297,564	129,260	85,144

Our undeveloped acreage expires as follows:

Expires in 2020	4%
Expires in 2021	2%
Expires in 2022	2%
Thereafter	92%
	100%

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and natural gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights.

Markets and Customers

The market for our production of oil and natural gas depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is currently sold under short-term contracts with a duration of six months or less. The contracts require the purchasers to purchase the amount of oil production that is available at prices tied to the spot oil markets. Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. We target selling approximately 70% of our natural gas on first of month index price, with the remaining 30% on spot market pricing. The percentage of natural gas sold on spot market pricing can be impacted when new wells commence production as such production is typically sold on spot market pricing during the month the well is first brought on line. Shell Oil Company and its subsidiaries, CIMA Energy, and Enterprise

Products Operating and its subsidiaries, accounted for 19%, 16%, and 12%, respectively, of our total 2019 sales. The loss of any of these customers would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

We have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production in North Louisiana to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We currently have agreements with two major natural gas marketing companies to provide us with firm transportation for an average of approximately 110,000 MMBtu per day for our natural gas production on the long-haul pipelines, which expire in October 2021. In October 2019, we entered into a firm transportation contract with a major natural gas marketing company as an anchor shipper for 400,000 MMBtu per day for our North Louisiana natural gas production. We expect deliveries under this commitment to commence in October 2021. The term of the firm transportation contract is ten years from commencement upon completion of construction.

To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements in North Louisiana is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or "FERC", regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or "NGA", and the Natural Gas Policy Act of 1978, or "NGPA". In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting all "first sales" of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management ("BLM") of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior's Bureau of Ocean Energy Management, Regulation & Enforcement ("BOEMRE"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC's regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC's regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2012 revised the methodology for this index to be based on PPI-FG plus

2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial 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 damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon “cap and trade” programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. The Trump Administration and Congress have made certain changes to applicable regulations, but the changes could be reversed or otherwise altered by a new administration. There are also costs associated with responding to changing regulations and policies, whether such regulations are more or less stringent. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act; or “CERCLA”, imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or “RCRA”, regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as “hazardous waste”. Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA’s definition of “hazardous wastes”, thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Certain oil and gas wastes may also contain naturally occurring radioactive materials (“NORM”), which is regulated by the federal Occupational Safety and Health Administration and state agencies. These regulations require certain worker protections and waste handling and disposal procedures. We believe our operations comply in all material respects with these worker protection and waste handling and disposal requirements.

Our operations are also subject to the Clean Air Act, or “CAA”, and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. On April 17, 2012, the U. S. Environmental Protection Agency or “EPA” promulgated new emission standards for the oil and gas industry. These rules require a nearly 95 percent reduction in volatile organic compounds (“VOCs”) emitted from hydraulically fractured gas wells by January 1, 2015. This significant reduction in emissions is to be accomplished primarily through the use of “green completions” (i.e., capturing natural gas that currently escapes to the air). These rules also have notification and reporting requirements. In 2014, EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending upon the date of construction of the storage tank). In 2016, EPA finalized regulations that required further reductions specifically regarding methane emissions. However, on September 24, 2019, EPA proposed amendments to the 2012 and 2016 rules. The proposed amendments would remove certain sources from regulation for VOCs, greenhouse gases and methane emissions. Although the proposed changes are described by EPA as reducing the regulatory burden on the oil and natural gas industry, these rules have not been finalized and their impact to our operations are difficult to predict. Nevertheless, there are costs associated with following the status and impacts of these changes, and implementing any changes as they become effective. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the “Clean Water Act”, imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

The Federal Safe Drinking Water Act of 1974, as amended, requires EPA to develop minimum federal requirements for Underground Injection Control ("UIC") programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water. The UIC program does not regulate wells that are solely used for production. However, EPA has authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. In February 2014, EPA issued guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We believe that our operations comply in all material respects with the requirements of the Federal Safe Drinking Water Act and similar state statutes. We believe the requirements are not any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Arkansas, California, Colorado, Illinois, Kansas, Ohio, Oklahoma, and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Texas, Colorado, Oklahoma, Kansas, New Mexico, and Arkansas. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. Also, the EPA may develop rules to specifically address the disposal of wastewater from oil and gas development and the potential for induced seismicity from wastewater injection. Future regulatory developments could adversely affect our operations by placing restrictions on the use of injection wells and hydraulic fracturing and/or causing us to incur increased operating expenses.

In December 2016, the EPA finalized its report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities could impact drinking water resources under some circumstances. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies have the potential to impact the likelihood or scope of future legislation or regulation.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention and response to oil spills in the waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or MPAs, in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right to Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities. Administrative policies with respect to such laws are also changing, and we incur costs to follow such changes and comply as changes become effective.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company's operations by regulatory agencies or the public. In 2012, the EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases, or GHGs, in January 2012, with the first annual reports of those emissions due on September 28, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO2 having the lowest global warming potential, so emissions of GHGs are typically expressed in terms of CO2 equivalents, or CO2e. The rule applies to facilities that emit 25,000 metric tons of CO2e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. These greenhouse gas reporting rules were amended on October 22, 2015 to expand the number of sources and operations that are subject to these rules, and again on November 18, 2016 to provide less burdensome reporting requirements. We have determined that these reporting requirements apply to us and we believe we have met all of the EPA required reporting deadlines and strive to ensure accurate and consistent emissions data reporting. It is possible that these requirements may be loosened or otherwise changed in the future. Other EPA actions with respect to the reduction of greenhouse gases (such as EPA's Greenhouse Gas Endangerment Finding, and EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and various state actions have or could impose mandatory reductions in greenhouse gas emissions. We are unable to predict at this time how much the cost of compliance with any legislation or regulation of greenhouse gas emissions will be in future periods.

The U.S. has not passed legislation to expressly address GHGs; however, in recent years the EPA moved ahead with its efforts to regulate GHG emissions from certain sources by rule. Beyond requiring measurement and reporting of GHGs as discussed above, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has adopted regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. States in which we operate may also require permits and reductions in GHG emissions. Additionally, the EPA published a set of final rules in 2016 that require reductions in VOC and methane generation from new sources. A portion of these rules were revised in 2018. In September 2019, EPA announced proposed rules to remove certain sources from regulation for VOCs, greenhouse gases, and methane emissions. Additional changes may still be forthcoming. Similarly, the Bureau of Land Management ("BLM") has proposed to suspend and revise a 2016 rule relating to methane venting, flaring, and leaks from oil and gas production on public lands that was being challenged by multiple western states and energy companies. In September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule. The 2018 rule is being challenged in federal court. Since all of our oil and natural gas production is in the United States, laws or regulations that have been or may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur substantial increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Most recently in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires ratifying countries to review and "represent a progression" in the ambitions of their nationally determined contributions, which set GHG emission reduction goals, every five years. The United States signed the Paris Agreement on April 22, 2016; however, the United States provided notice on November 4, 2019 of its intent to withdraw from the Paris Agreement. Without further action, the withdrawal will become effective one year later. A new administration may change this outcome. It is difficult to predict the timing and certainty of any future government action and the effect on our operations. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. However, we expect that the impacts to our operations will not be materially different from other similarly situated companies involved in oil and natural gas exploration and production activities.

In 2010 the BLM began implementation of a proposed oil and gas leasing reform that would increase environmental review requirements and was expected to have the effect of reducing the amount of new federal lands made available for lease, increasing the competition for and cost of available parcels. This leasing reform initiative was replaced by a new BLM policy, dated January 31, 2018, which is expected to remove the additional environmental review created under the 2010 initiative and streamline the leasing process. Additionally, on December 28, 2017, the BLM rescinded a rule the BLM adopted in 2015 concerning hydraulic fracturing on federal land. The 2015 rule would have required increased well integrity testing, increased requirements for the managing of fluids, and the disclosure of chemicals used in fracturing. Due to the ongoing regulatory and legal uncertainty, we cannot predict what effect these changes will have on our operations, though the changes may be advantageous. We expect that the impacts to our operations will be similar to other similarly situated companies involved in oil and natural gas exploration and production activities.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. Adoption of new regulations further regulating emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties. It is also possible that certain states may increase regulatory activity in response to changing federal regulations or policies.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 66,382 square feet at a monthly rate of $129,998. This lease expires on December 31, 2021. In connection with the Covey Park Acquisition, we assumed an office lease in Dallas, Texas which expires in September 2022. We also own production offices and pipe yard facilities near Carthage, Franklin, Greenwood, Nacogdoches and Marshall, Texas and Bossier City, Grand Cane, Homer and Logansport, Louisiana.

Employees

As of December 31, 2019, we had 207 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors	64
Roland O. Burns	President, Chief Financial Officer, Secretary and Director	59
Daniel S. Harrison	Chief Operating Officer	56
David J. Terry	Senior Vice President of Corporate Development	39
Patrick H. McGough	Vice President of Operations	39
Ronald E. Mills	Vice President of Finance and Investor Relations	48
Daniel K. Presley	Vice President of Accounting, Controller and Treasurer	59
Russell W. Romoser	Vice President of Reservoir Engineering	68
LaRae L. Sanders	Vice President of Land	57
Whitney H. Ward	Vice President of Marketing	35
Mark E.Wilson	Vice President of Financial Reporting	60
Elizabeth B. Davis	Director	57
Morris E. Foster	Director	77
John D. Jacobi	Director	65
Jordan T. Marye	Director	39
Jim L. Turner	Director	74

A brief biography of each person who serves as an executive officer or director follows below.

Executive Officers

M. Jay Allison has been our Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the Board in 1997 and has been a director since 1987. From 1988 to 2013, Mr. Allison served as our President. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison presently serves on the Board of Regents for Baylor University.

Roland O. Burns has been our President since 2013, Chief Financial Officer since 1990, Secretary since 1991 and a director since 1999. Mr. Burns served as our Senior Vice President from 1994 to 2013 and Treasurer from 1990 to 2013. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant. Mr. Burns also serves on the Board of Directors and the audit committee of the University of Mississippi Foundation.

Daniel S. Harrison became our Chief Operating Officer in July 2019 and served as Vice President of Operations since 2017. Mr. Harrison has been with us since 2008 and served in various engineering and operations management positions of increasing responsibility during that time. Prior to joining us, Mr. Harrison was an operations engineer at Cimarex Energy Company from 2005 to 2008. Prior to 2005 he worked in various petroleum engineering operations management positions for several independent oil and gas exploration and development companies. Mr. Harrison received a B.S. Degree in Petroleum Engineering from the Louisiana State University in 1985.

David J. Terry became our Senior Vice President of Corporate Development in July 2019 concurrently with the closing of the Covey Park Acquisition. In this role, Mr. Terry is responsible for driving our long-term strategy for acquisitions and development, reserves and midstream. Prior to co-founding Covey Park, Mr. Terry held significant roles in operations and business development at EXCO Resources, Inc. and Winchester Production. Mr. Terry received a Bachelor of Science in Petroleum Engineering from Louisiana State University in 2005 and is involved with the SPE and ADAM Energy Forum.

Patrick H. McGough became our Vice President of Operations in July 2019 following the Covey Park Acquisition. He joined Covey Park in August 2018 as the Vice President of Operations, where he was responsible for drilling, completion, and production operations and engineering. Prior to his time at Covey Park, Mr. McGough held significant roles as a drilling, completion, and production engineer at Brammer Engineering. Mr. McGough received a Bachelor of Science in Chemical Engineering from Louisiana Tech University in 2003 and an MBA from Centenary College of Louisiana in 2010.

Ronald E. Mills became our Vice President of Finance and Investor Relations in August 2019. Prior to joining us, Mr. Mills was an Equity Member and Senior Analyst responsible for covering small and mid-cap domestic exploration and production companies at Johnson Rice & Company LLC. Mr. Mills held progressive roles of responsibility since joining Johnson Rice in August 1995. Mr. Mills earned his Bachelor of Arts in Economics and Master of Business Administration from Tulane University in 1994 and 1995, respectively.

Daniel K. Presley has been our Treasurer since 2013. Mr. Presley, who has been with us since 1989, also continues to serve as our Vice President of Accounting and Controller, positions he has had held since 1997 and 1991, respectively. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. degree from Texas A & M University in 1983.

Russell W. Romoser has been our Vice President of Reservoir Engineering since 2012. Mr. Romoser has over 40 years of experience as a reservoir engineer both with industry and with a petroleum engineering consulting firm. Prior to joining us, Mr. Romoser served eleven years as the Acquisitions Engineering Manager for EXCO Resources, Inc. Mr. Romoser received a B.S. Degree in Petroleum Engineering in 1975 and a Master's degree in Petroleum Engineering in 1976 from the University of Texas and is a Registered Professional Engineer in Oklahoma and Texas.

LaRae L. Sanders has been our Vice President of Land since 2014. Ms. Sanders has been with us since 1995. She has served as Land Manager since 2007, and has been instrumental in all of our active development programs and major acquisitions. Prior to joining us, Ms. Sanders held positions with Bridge Oil Company and Kaiser-Francis Oil Company, as well as other independent exploration and production companies. Ms. Sanders is a Certified Professional Landman with 37 years of experience. She became the nation's first Certified Professional Lease and Title Analyst in 1990.

Whitney H. Ward became our Vice President of Marketing in July 2019 concurrently with the closing of the Covey Park Acquisition, where she also served as Vice President of Marketing. She joined

Covey Park in 2014, and started the marketing department. Prior to joining Covey Park, Ms. Ward held various positions in the marketing department at EXCO Resources, Inc. from 2007 through 2014. She earned her Bachelor's degree in Communication Studies from The University of Texas at Austin in 2007.

Mark E. Wilson became our Vice President of Financial Reporting in July 2019 upon closing of the Covey Park Acquisition, where he served as Senior Vice President & Chief Accounting Officer since May 2017. Prior to joining Covey Park, Mr. Wilson was an independent consultant in the E&P sector, working with clients on IPO readiness and accounting efficiencies. Over the course of his career, Mr. Wilson has held various roles of responsibility in both private and public E&P companies, including Vice President and Chief Accounting Officer of Petro Harvester between 2013 and 2015 and EXCO Resources, Inc. from 2005 through 2013. Mr. Wilson also served as Chief Financial Officer of Epoch Investment Partners, a registered investment adviser from 2000 through 2005. He earned his Bachelor's degree in Accounting from Eastern New Mexico University in 1980, is a Certified Public Accountant and serves as a member of the Board of Directors of Professional Development Institute, a not-for-profit affiliate of the University of North Texas.

Outside Directors

Elizabeth B. Davis has served as a director since 2014. Dr. Davis is currently the President of Furman University. Dr. Davis was the Executive Vice President and Provost for Baylor University until July 2014, and served as Interim Provost from 2008 until 2010. Prior to her appointment as Provost, she was a professor of accounting in the Hankamer School of Business at Baylor University where she also served as associate dean for undergraduate programs and as acting chair for the Department of Accounting and Business Law. Prior to joining Baylor University, she worked for the public accounting firm Arthur Andersen from 1984 to 1987.

Morris E. Foster has served as a director since 2017. Mr. Morris retired in 2008 as Vice President of ExxonMobil Corporation and President of ExxonMobil Production Company following more than 40 years of service with the ExxonMobil group. Mr. Foster served in a number of production engineering and management roles domestically as well as in the United Kingdom and Malaysia prior to his appointment in 1995 as a Senior Vice President in charge of the upstream business of Exxon Company, USA. In 1998, Mr. Foster was appointed President of Exxon Upstream Development Company, and following the merger of Exxon and Mobil in 1999, he was named to the position of President of ExxonMobil Development Company. In 2004, Mr. Foster was named President of Exxon Mobil Production Company, the division responsible for ExxonMobil's upstream oil and gas exploration and production business, and a Vice President of ExxonMobil Corporation. Mr. Foster currently serves as Chairman of Stagecoach Properties Inc., a real estate holding corporation with properties in Salado, Houston and College Station, Texas and Carmel, California and as a member of the Board of Regents of Texas A&M University. In addition, Mr. Foster currently serves on the board of directors of Scott & White Medical Institute and First State Bank of Temple, Texas.

John D. Jacobi became a director in July 2019 upon closing of the Covey Park Acquisition. Mr. Jacobi served as Co-CEO of Covey Park since its inception in June 2013. From 1999 through June 2013, he served as Vice President of Business Development and Marketing at EXCO Resources, Inc. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer, and served as its President, focusing on acquisitions in the Ark-La-Tex and Gulf Coast Basins before it was sold to EXCO Resources, Inc. in 1998. Mr. Jacobi began his full-time employment in the energy business in 1981 working for Woolf & Magee, Inc., a drilling, exploration and production company.

Jordan T. Marye became a director in July 2019 upon closing of the Covey Park Acquisition. He joined Denham Capital in 2006 and is currently a Managing Partner of Denham Capital Management where he leads the firm's Oil & Gas investment effort. Prior to joining Denham, Mr. Marye worked in the Global Energy Group of UBS Investment Bank and the Energy Practice of Huron Consulting Group. He currently serves on the Board of Directors of multiple Denham portfolio companies/investments including Comstock, Fairway Resources III, Clear Creek Resource Partners, Spire HoldCo, Atlantic Resources I & II, and Rockies Resources. Mr. Marye received a Bachelor of Science from Louisiana State University in 2003.

Jim L. Turner has served as a director since 2014. Mr. Turner currently serves as CEO of JLT Automotive, Inc. Mr. Turner served as President and Chief Executive Officer of Dr. Pepper/Seven Up Bottling Group, Inc. from its formation in 1999 through 2005, when he sold this interest in that company. Prior to that, Mr. Turner served as Owner/Chairman of the Board and Chief Executive Officer of the Turner Beverage Group, the largest privately owned independent bottler in the United States. Mr. Turner currently serves as a non-executive Chairmen of the Board of Directors for Dean Foods Company where he also serves as Chairman of the Compensation Committee and a member of the Nominating/Corporate Governance Committee. He is past-Chairman and currently serves on the Board of Trustees of Baylor Scott and White Health, the largest not-for-profit healthcare system in the State of Texas, where he also serves as Chairman of the Finance Committee and as a member of the Executive Committee. He is a Director of Crown Holdings where he also serves as Chairman of the Compensation Committee and as a member of the Nominating and Governance Committee. He is on the Board of Directors of INSURICA, a full service insurance agency.

Available Information

Our executive offices are located at 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034. Our telephone number is (972) 668-8800. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

ITEM 1A. *RISK FACTORS*

You should carefully consider the following risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting us, but the below risks and uncertainties are not the only ones related to our businesses and are not necessarily listed in the order of their significance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business.

An extended period of depressed oil and natural gas prices will adversely affect our business, financial condition, cash flow, liquidity, results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our business is heavily dependent upon the prices of, and demand for, oil and natural gas. Historically, the prices for oil and natural gas have been volatile and are likely to remain volatile in the future. During 2019, commodity prices fluctuated significantly, with the settlement price for West Texas Intermediate ("WTI") crude oil ranging from a high of approximately $66.24 per barrel to a low of approximately $46.31 per barrel and settlement prices for Henry Hub natural gas ranging from a high of approximately $4.25 per Mcf to a low of approximately $1.75 per Mcf. Oil and natural gas price volatility continued into 2020 and, through February 28, 2020, the WTI settlement price of crude oil had a low of approximately $44.76 per barrel, and the Henry Hub settlement price of natural gas reached a low of approximately $1.72 per Mcf.

The prices we receive for our oil and natural gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of oil, natural gas liquids and natural gas;
- weather conditions;
- the price and quantity of imports of oil and natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global oil and natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

Lower oil and natural gas prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved oil and natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

Our debt service requirements could adversely affect our operations and limit our growth.

We had $2.7 billion principal amount of debt as of December 31, 2019.

Our outstanding debt has important consequences, including, without limitation:

- a portion of our cash flow from operations is required to make debt service payments;
- our ability to borrow additional amounts for capital expenditures (including acquisitions) or other purposes is limited; and
- our debt limits (i) our ability to capitalize on significant business opportunities, (ii) our flexibility in planning for or reacting to changes in market conditions, and (iii) our ability to withstand competitive pressures and economic downturns.

Future acquisitions or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our debt agreements contain a number of significant covenants. These covenants limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the indentures governing our outstanding notes. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us.

Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you that we will have adequate capital resources to conduct acquisition and drilling activities or that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return and firm transportation commitments.

A prospect is a property in which we own an interest, or have operating rights to, and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return.

Further, unsuccessful drilling may impact our ability to fulfill our firm transportation commitments. We recently entered into an agreement with Enterprise Products Partner to be an anchor shipper on its new one Bcf per day Haynesville Acadian Extension to transport gas to the Gillis Hub. As part of this agreement we entered into firm transportation commitments that may be incurred in the event of unsuccessful drilling operations.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our success depends on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of the above operating risks, our well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We maintain insurance against “sudden and accidental” occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

We operate in a highly competitive industry, and our failure to remain competitive with our competitors, many of which have greater resources than we do, could adversely affect our results of operations.

The oil and natural gas industry is highly competitive in the search for and development and acquisition of reserves. Our competitors often include companies that have greater financial and personnel resources than we do. These resources could allow those competitors to price their products and services more aggressively than we can, which could hurt our profitability. Moreover, our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to close transactions in a highly competitive environment.

If oil and natural gas prices decline further or continue to remain low for an extended period of time, we may be required to further write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties, which would constitute a non-cash charge to earnings and adversely affect our results of operations.

Accounting rules applicable to us require that we periodically review the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We did not recognize any impairments in 2018 or 2019. We may however, incur non-cash impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The information regarding the present value of future net cash flows attributable to our proved oil and natural gas reserves is only an estimate and should not be construed as the current market value of the oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

As of December 31, 2019, 64% of our total proved reserves were undeveloped and 1% were developed non-producing. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced at the time periods we have planned, at the costs we have budgeted, or at all. As a result, we may not find commercially viable quantities of oil and natural gas, which in turn may result in a material adverse effect on our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage.

Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the leased properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

We pursue acquisitions as part of our growth strategy and there are risks associated with such acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. More recently we have been focused on acquiring acreage for our drilling program. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in Texas and Louisiana, we may pursue acquisitions or properties located in other geographic areas.

If we are unsuccessful at marketing our oil and natural gas at commercially acceptable prices, our profitability may decline.

Our ability to market oil and natural gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;

- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could negatively affect our profitability.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and processing facilities. Our ability to market our production depends in a substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, which, in some cases, may be owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to a lack of market demand or because of the inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

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

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, as well as the safe operations thereof. Future laws or regulations, adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with present and future governmental laws and regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- regulatory requirements; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from various sources for use in our operations. If we are unable to obtain water from local sources to use in our operations, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

Our operations may incur substantial liabilities due to compliance with environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment and otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of one or more permits before drilling commences;
- impose limitations on where drilling can occur and/or requires mitigation before authorizing drilling in certain locations;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- require reporting of significant releases, and annual reporting of the nature and quantity of emissions, discharges and other releases into the environment;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- the incurrence of investigatory and/or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly restrictions on emissions, and/or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination, even if our operations met previous industry standards at the time they were performed. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Legislation or regulation that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

There is also the potential that climate change may result in physical risks, including sea level rise or an increase or changes in precipitation and extreme weather events, which could adversely affect our operations. In addition, changing weather including increased temperatures could alter consumer demand for our products. Because of the uncertainty in severity, scope and timing of such events, we are unable to predict the impacts of such events. The costs of compliance with these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

Our hedging transactions could result in financial losses or could reduce our income. To the extent we have hedged a significant portion of our expected production and our actual production is lower than we expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and gas, we have entered into and may continue to enter into hedging transactions for certain of our expected oil and natural gas production. These transactions could result in both realized and unrealized hedging losses. Further, these hedges may be inadequate to protect us from continuing and prolonged declines in the price of oil and natural gas. To the extent that the prices of oil and natural gas remain at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are primarily based on NYMEX futures prices, which may differ significantly from the actual crude oil and gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our revolving credit facility also requires, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative financial instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions. If our actual future production is higher than we estimated, we will have greater commodity price exposure than we intended. If our actual future production is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our hedging transactions are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative financial instrument or may seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risks, interest rate risks and other risks associated with our business.

In 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank”), was enacted that established federal oversight regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Dodd-Frank requires the Commodities Futures Trading Commission, or CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. Although the CFTC has finalized most of its regulations under the Dodd-Frank Act, it continues to review and refine its initial rulemakings through additional interpretations and supplemental rulemakings. As a result, it is not possible at this time to predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations may increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the regulations thereunder, 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 investing.

In December 2016, the CFTC re-proposed new rules that would place federal limits on positions in certain core futures and equivalent swap contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions and finalized a companion rule on aggregation of positions among entities under common ownership or control. If finalized, the position limits rule may have an impact on our ability to hedge our exposure to certain enumerated commodities.

The CFTC has designated certain interest rate swaps and credit default swaps for 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. In addition the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we currently qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to the other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

Finally, the Dodd-Franks Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as restrict our access to our oil and gas reserves.

Hydraulic fracturing is an essential and common practice that is used to stimulate production of oil and natural gas from dense subsurface rock formations such as shale and tight sands. We routinely apply hydraulic fracturing techniques in completing our wells. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs including the Haynesville shale, Bossier shale, Eagle Ford shale, Cotton Valley and other tight natural gas and oil reservoirs. Substantially all of our proved oil and gas reserves that are currently not producing and our undeveloped acreage require hydraulic fracturing to be productive. All of the wells currently being drilled by us utilize hydraulic fracturing in their completion and hydraulic fracturing services comprise approximately 35% of our capital budget in 2020.

The use of hydraulic fracturing in our well completion activities could expose us to liability for negative environmental effects that might occur. Although we have not had any incidents related to hydraulic fracturing operations that we believe have caused any negative environmental effects, we have established operating procedures to respond and report any unexpected fluid discharge which might occur during our operations, including plans to remediate any spills that might occur. In the event that we were to suffer a loss related to hydraulic fracturing operations, our insurance coverage will be net of a deductible per occurrence and our ability to recover costs will be limited to a total aggregate policy limit of $26.0 million, which may or may not be sufficient to pay the full amount of our losses incurred.

Issuance of our common stock in connection with the conversion of our outstanding convertible preferred stock would cause substantial dilution, which could materially affect the trading price of our common stock and earnings per share.

As part of the Covey Park Acquisition, we issued 210,000 shares of Series A Convertible Preferred Stock with a face value of $210.0 million as part of the consideration for the acquisition and sold 175,000 shares of Series B Convertible Preferred Stock for $175.0 million to our majority stockholder. At any time after July 16, 2020, each holder may convert any or all shares of preferred stock into shares of our common stock at the then prevailing conversion rate. The conversion price of the preferred stock is $4.00 per share of common stock, subject to adjustment pursuant to customary anti-dilution provisions. As a result, upon a conversion large amounts of our common stock would be issued resulting in a decrease to our stock price and earnings per share. Further, holders of the newly issued convertible preferred stock are entitled to receive quarterly dividends at a rate of 10% per annum, which are paid in arrears.

Our access to capital markets may be limited in the future.

Adverse changes in the financial and credit markets could negatively impact our ability to grow production and reserves and meet our future obligations. In addition, the continuation of the current low oil and natural gas price environment, or further declines of oil and natural gas prices, will affect our ability to obtain financing for acquisitions and drilling activities and could result in a reduction in drilling activity, which could lead to a loss of acreage due to lease expirations, both of which could negatively affect our ability to replace reserves.

Drilling and completion activities are typically regulated by state oil and natural gas commissions. Our drilling and completion activities are conducted primarily in Louisiana and Texas. Texas adopted a law in June 2012 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition, Congress has considered legislation that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. In June 2015, the EPA released a draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water resources in the United States, although there may be above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. The draft report was finalized in December 2016. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies have the potential to impact the likelihood or scope of future legislation or regulation.

State and federal regulatory agencies have recently focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Arkansas, California, Colorado, Illinois, Kansas, Ohio, Oklahoma, and Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Texas, Colorado, Oklahoma, Kansas, New Mexico, and Arkansas. In addition, a number of lawsuits have been filed, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. Future regulatory developments could adversely affect our operations by placing restrictions on the use of injection wells and hydraulic fracturing.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could have a material adverse effect on our results of operations, financial condition, or cash flows.

We make judgments regarding the utilization of existing income tax credits and the potential tax effects of various financial transactions and results of operations to estimate our obligations to taxing authorities. Tax obligations include income, franchise, real estate, sales and use, and employment-related taxes. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken. Changes in federal, state, or local tax laws, adverse tax audit results, or adverse tax rulings on positions taken by us could have a material adverse effect on our results of operations, financial condition, or cash flows.

The Budget Reconciliation Act, commonly referred to as the Tax Cuts and Jobs Act (hereinafter "Tax Cuts and Jobs Act"), was signed into law on December 22, 2017. The Tax Cuts and Jobs Act resulted in a net tax benefit to us of approximately $20.4 million in 2018, which was attributable primarily to the termination of the corporate alternative minimum tax. The Tax Cuts and Jobs Act is expected to have a favorable impact on our effective tax rate and net income as reported under generally accepted accounting principles in future reporting periods to which the Tax Cuts and Jobs Act is effective. However, we are still assessing the full impact of the Tax Cuts and Jobs Act, including the impact on state taxes, and there can be no assurances that it will have a favorable impact on us or our future financial results.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of these programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include loss of our communication links, our inability to find, produce, process and sell oil and natural gas and the inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any of these consequences could have a material effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security or operation of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, either to the Company or a third party upon which we rely, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk particularly in light of the sustained declines in oil and natural gas prices since mid-2014. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Substantial exploration and development activities could require significant outside capital, which could dilute the value of our common shares and restrict our activities. Also, we may not be able to obtain needed capital or financing on satisfactory terms, which could lead to a limitation of our future business opportunities and a decline in our oil and natural gas reserves.

We expect to expend substantial capital in the acquisition of, exploration for and development of oil and natural gas reserves. In order to finance these activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of non-strategic assets or other means. The issuance of additional equity securities could have a dilutive effect on the value of our common shares, and may not be possible on terms acceptable to us given the current volatility in the financial markets. The issuance of additional debt would likely require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions, dividends and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our estimated proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- our ability to extract natural gas liquids from the natural gas we produce;
- the prices at which oil, natural gas liquids and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

The unavailability or high cost of drilling rigs, equipment, supplies, qualified personnel and oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry has experienced a shortage of drilling rigs, equipment, supplies and qualified personnel in prior years as the result of higher demand for these services. Shortages of drilling rigs, equipment, supplies or qualified personnel in the areas in which we operate could delay or restrict our exploration and development operations, which in turn could adversely affect our financial condition and results of operations because of our concentration in those areas.

We depend on our key personnel and the loss of any of these individuals could have a material adverse effect on our operations.

We believe that the success of our business strategy and our ability to operate profitably depend on the continued employment of M. Jay Allison, our Chief Executive Officer, and Roland O. Burns, our President and Chief Financial Officer, and a limited number of other senior management personnel. Loss of the services of Mr. Allison, Mr. Burns or any of those other individuals could have a material adverse effect on our operations.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

If we suffer a significant accident or other loss, our insurance coverage will be net of our deductibles and may not be sufficient to pay the full current market value or current replacement value of our lost investment, which could result in a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third party drilling contractors are used to drill our wells, we may not realize the full benefit of workers' compensation laws in dealing with their employees. In addition, some risks, including pollution and environmental risks, generally are not fully insurable.

Provisions of our restated articles of incorporation, bylaws and Nevada law will make it more difficult to effect a change in control of us, which could adversely affect the price of our common stock.

Nevada corporate law and our restated articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us. These provisions include:

- allowing for authorized but unissued shares of common and preferred stock;
- requiring special stockholder meetings to be called only by our chairman of the board, our chief executive officer, a majority of the board, a majority of our executive committee or the holders of a majority of our outstanding stock;
- requiring removal of directors by a supermajority stockholder vote;
- prohibiting cumulative voting in the election of directors; and
- Nevada control share laws that may limit voting rights in shares representing a controlling interest in us.

These provisions could make an acquisition of us by means of a tender offer or proxy contest or removal of our incumbent directors more difficult. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

The Company is controlled by significant stockholders who have the power to determine the outcome of all matters submitted to the stockholders for approval and whose interest in the Company may be different than yours.

As of December 31, 2019, the Jones Partnerships, owned in the aggregate approximately 73% of our outstanding common stock. This would give the Jones Partnerships the power to:

- control the Company's management and policies; and
- determine the outcome of any corporate transaction or other matter requiring stockholder approval, including charter amendments, mergers, consolidations, financings and asset sales.

The Jones Partnerships may have interests that are different than yours in making these decisions.

In addition, pursuant to a Shareholders Agreement among the Jones Partnerships, New Covey Park Energy LLC ("CPE") and us, as long as CPE beneficially owns at least 10% of our outstanding common stock or 21,000 shares of our Series A Preferred Stock, CPE has the right to approve certain major decisions by us, including certain acquisitions and incurrence of indebtedness.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

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*

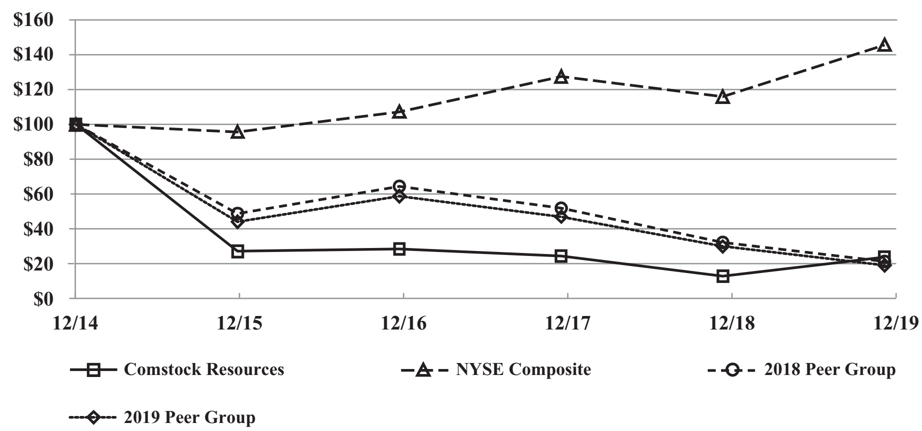
Our common stock is listed for trading on the New York Stock Exchange under the symbol "CRK". As of February 26, 2020, we had 190,004,776 shares of common stock outstanding, which were held by 73 holders of record and approximately 13,000 beneficial owners who maintain their shares in "street name" accounts. We have not paid dividend on our common stock since 2014. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant.

Stockholder Return Performance

A peer group of companies is used by our compensation committee to determine total stockholder return performance which is used as a metric in our Annual Incentive Plan and to determine whether performance share units are earned as awarded under our 2019 Long-term Incentive Plan. For 2019, the compensation committee utilized a peer group that consisted of Antero Resources Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, CNX Resources Corporation, EQT Corporation, Gulfport Energy Corporation, Montage Resources Corporation, Range Resources Corporation, SilverBow Resources, Inc. and Southwestern Energy Company. For 2018, the compensation committee utilized a peer group, which consisted of Antero Resources Corporation, Approach Resources, Inc., Cabot Oil & Gas Corporation, Contango Oil & Gas Company, CNX Resources Corporation, Eclipse Resources Corporation, EQT Corporation, Goodrich Petroleum Corporation, Gulfport Energy Corporation, QEP Resources, Inc., Range Resources Corporation, SilverBow Resources, Inc., Southwestern Energy Company and Ultra Petroleum Corporation. The following graph compares the yearly percentage change in the cumulative total stockholder return on our common stock during the five years ended December 31, 2019 with the cumulative return on the New York Stock Exchange Index and the cumulative return for our peer group. The graph assumes that $100.00 was invested on the last trading day of 2014, and that dividends, if any, were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN(1)(2)
Among Comstock, the NYSE Composite Index, and Our Peer Group

	As of December 31,					
Total Return Analysis	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Comstock	$100.00	$27.46	$ 28.93	$ 24.85	$ 13.30	$ 24.17
NYSE Composite	$100.00	$95.91	$107.36	$127.46	$116.06	$145.66
2018 Peer Group	$100.00	$49.20	$ 64.73	$ 52.14	$ 32.61	$ 21.75
2019 Peer Group	$100.00	$44.38	$ 59.05	$ 47.31	$ 30.24	$ 19.49



(1) $100 investment on December 31, 2014 in stock or index, including reinvestment of dividends, fiscal year ending December 31.

(2) The data contained in the above graph is deemed to be furnished and not filed pursuant to Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

ITEM 6. *SELECTED FINANCIAL DATA*

The historical financial data presented in the table below as of and for each of the three years ended December 31, 2017, for the Predecessor Period from January 1, 2018 through August 13, 2018 and for the Successor Period from August 14, 2018 through December 31, 2018, and the year ended December 31, 2019 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Statement of Operations Data:

	Predecessor				Successor	
	Year Ended December 31,					
	2015	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands, except per share data)					
Natural gas sales	$ 109,753	$ 122,623	$ 208,741	$ 147,897	$144,236	$ 635,795
Oil sales	142,669	53,083	46,590	18,733	79,385	132,894
Total oil and gas sales	252,422	175,706	255,331	166,630	223,621	768,689
Operating expenses:						
Production taxes	10,286	4,933	5,373	3,659	11,155	29,181
Gathering and transportation	14,298	15,824	17,538	11,841	10,511	71,303
Lease operating	64,502	47,696	37,859	21,139	20,736	87,283
Exploration	70,694	84,144	—	—	—	241
Depreciation, depletion and amortization	321,323	141,487	123,557	68,032	53,944	276,526
General and administrative, net	23,541	23,963	26,137	15,699	11,399	29,244
Impairment of oil and gas properties	801,347	27,134	43,990	—	—	—
Loss (gain) on sale of oil and gas properties	112,085	14,315	1,060	35,438	(155)	25
Total operating expenses	1,418,076	359,496	255,514	155,808	107,590	493,803
Operating income (loss)	(1,165,654)	(183,790)	(183)	10,822	116,031	274,886
Other income (expenses):						
Gain (loss) from derivative financial instruments	2,676	(5,356)	16,753	881	10,465	51,735
Gain on extinguishment of debt	78,741	189,052	—	—	—	—
Other income	1,275	872	530	677	173	622
Transaction costs	—	—	—	(2,866)	—	(41,010)
Interest expense	(118,592)	(128,743)	(146,449)	(101,203)	(43,603)	(161,541)
Total other income (expenses)	(35,900)	55,825	(129,166)	(102,511)	(32,965)	(150,194)
Income (loss) before income taxes	(1,201,554)	(127,965)	(129,349)	(91,689)	83,066	124,692
Benefit from (provision for) income taxes	154,445	(7,169)	17,944	(1,065)	(18,944)	(27,803)
Net income (loss)	(1,047,109)	(135,134)	(111,405)	(92,754)	64,122	96,889
Preferred stock dividends	—	—	—	—	—	(22,415)
Net income (loss) available to common stockholders	$(1,047,109)	$(135,134)	$(111,405)	$ (92,754)	$ 64,122	$ 74,474
Net income (loss) per share – basic and diluted	$ (113.53)	$ (11.52)	$ (7.61)	$ (6.08)	$ 0.61	0.52
Weighted average shares outstanding:						
Basic	9,223	11,729	14,644	15,262	105,453	142,750
Diluted	9,223	11,729	14,644	15,262	105,459	187,378

Balance Sheet Data:

	As of December 31,				
	Predecessor			Successor	
	2015	2016	2017	2018	2019
			(In thousands)		
Cash and cash equivalents	$ 134,006	$ 65,904	$ 61,255	$ 23,193	$ 18,532
Property and equipment, net	1,038,420	798,662	607,929	1,667,979	4,008,803
Total assets	1,195,850	889,874	930,419	2,187,840	4,657,122
Total debt	1,249,330	1,044,506	1,110,529	1,244,363	2,500,132
Stockholders' equity	(171,258)	(271,269)	(369,272)	569,571	1,143,022

Cash Flow Data:

	Predecessor				Successor	
	2015	2016	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	2019
			(In thousands)			
Cash flows provided by (used for) operating activities	$ 30,086	$(23,728)	$ 174,614	$ 85,735	$ 102,302	$ 451,237
Cash flows used for investing activities	(1,611,725)	(29,569)	(178,953)	(50,205)	(161,634)	(1,170,839)
Cash flows provided by (used for) financing activities	263,574	(14,805)	(310)	(797,402)	(811,662)	714,941

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

The following discussion and analysis should be read in conjunction with our selected historical consolidated financial data and our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas in the United States. Our assets are concentrated in the Haynesville and Bossier shale located in East Texas and North Louisiana, a premier natural gas basin with superior economics and geographic proximity to Gulf Coast markets. Approximately 93% of our December 31, 2019 proved reserves are located in the Haynesville and Bossier shale region. We own interests in 2,800 producing oil and natural gas wells (1,410.8 net to us) and we operate 1,430 of these wells. We intend to maintain an operating plan in 2020 targeting leverage reduction and generation of free cash flow.

Our growth is driven primarily by our acquisition, development and exploration activities. In 2019 our growth in natural gas production and proved reserves was primarily driven by the Covey Park Acquisition and our drilling activities. We plan to spend approximately $421.0 million in 2020 for our development and exploration activities, which will be focused primarily on Haynesville and Bossier shale projects.

We use the successful efforts method of accounting, which allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration activities. Accordingly, our exploration costs consist of costs we incur to acquire and reprocess 3-D seismic data, impairments of our unevaluated leasehold where we were not successful in discovering reserves and the costs of unsuccessful exploratory wells that we drill.

We generally sell our oil and natural gas at current market prices at the point our wells connect to third party purchaser pipelines or terminals. We have entered into certain transportation and treating agreements with midstream and pipeline companies to transport a substantial portion of our natural gas production to long-haul gas pipelines. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product, the availability and cost of pipelines near our wells, market prices, pipeline constraints and operational flexibility. Accordingly, our revenues are heavily dependent upon the prices of, and demand for, oil and natural gas. Oil and natural gas prices have historically been volatile and are likely to remain volatile in the future.

Our operating costs are generally comprised of several components, including costs of field personnel, insurance, repair and maintenance costs, production supplies, fuel used in operations, transportation costs, workover expenses and state production and ad valorem taxes.

Like all oil and natural gas exploration and production companies, we face the challenge of replacing our reserves. Although in the past we have offset the effect of declining production rates from existing properties through successful acquisition and drilling efforts, there can be no assurance that we will be able to continue to offset production declines or maintain production at current rates through future acquisitions or drilling activity. Our future growth will depend on our ability to continue to add new reserves in excess of production.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may have an adverse effect on our business, results of operations and financial condition. Applicable environmental regulations require us to remove our equipment after production has ceased, to plug and abandon our wells and to remediate any environmental damage our operations may have caused. The present value of the estimated future costs to plug and abandon our oil and gas wells and to dismantle and remove our production facilities is included in our reserve for future abandonment costs, which was $18.1 million as of December 31, 2019.

Prices for crude oil and natural gas have been highly volatile, and we are currently experiencing a period of low prices primarily due to an oversupply of natural gas. As natural gas prices remain low, we will continue to experience lower revenues and cash flows. We expect our oil production to continue to decline as we have limited future plans to participate in the drilling of new oil wells. We expect our natural gas production to increase, assuming we maintain a sufficient development program to offset declines. The drilling activity level is dependent on commodity prices. If we do not offset production declines from production from the new wells we plan to drill in 2020 and future periods, our production volumes and our cash flows from our operating activities may not be sufficient to fund our capital expenditures, and we may need to either curtail drilling activity or we may seek additional borrowings which would increase our interest expense in 2020 and in future periods. We may need to recognize impairments if oil and natural gas prices remain low, and as a result, the expected future cash flows from these properties becomes insufficient to recover their carrying value.

Jones Contribution

On August 14, 2018, the Jones Partnerships contributed certain oil and gas properties in North Dakota and Montana in exchange for 88,571,429 newly issued shares of common stock representing 84% of our then outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group"). References to "Successor" or "Successor Company" relate to the operations of the Company subsequent to August 13, 2018. References to "Predecessor" or "Predecessor Company" relate to the operations of the Company on or prior to August 13, 2018.

To enhance the analysis of our operating results for the periods presented, we have included a discussion of selected financial and operating data of the Predecessor and Successor on a combined basis for the year ended December 31, 2018. This presentation consists of the mathematical addition of selected financial and operating data of the Predecessor for the period from January 1, 2018 to August 13, 2018 plus the comparable financial and operating data of the Successor for the period from August 14, 2018 to December 31, 2018. There are no other adjustments made in the combined presentation. The mathematical combination of selected financial and operating data is included below under the heading "Combined Year Ended December 31, 2018" and this data is a non-GAAP presentation. Management believes that this selected financial and operating data provides investors with useful information upon which to assess our operating performance because the results of operations for a twelve-month period correspond to how we have reported our results in the past and how we will report our results in the future.

Covey Park Acquisition

On July 16, 2019, we acquired Covey Park Energy LLC ("Covey Park") for total consideration of $700.0 million of cash, the issuance of Series A Convertible Preferred Stock with a redemption value of $210.0 million, and the issuance of 28,833,000 shares of common stock (the "Covey Park Acquisition"). In addition to the consideration paid, Comstock assumed $625.0 million of Covey Park's 7.5% senior notes, repaid $380.0 million of Covey Park's then outstanding borrowings under its bank credit facility and redeemed all of Covey Park's preferred equity for $153.4 million. Based on the fair value of the preferred stock issued and the closing price of our common stock of $5.82 per share on July 16, 2019, the transaction was valued at approximately $2.2 billion. Covey Park's operations are focused primarily in the Haynesville / Bossier shale in East Texas and North Louisiana.

Funding for the Covey Park Acquisition was provided by the sale of 50.0 million newly issued shares of our common stock for $300.0 million and 175,000 shares of newly issued Series B Convertible Preferred Stock for $175.0 million to our majority stockholder and by borrowings under our amended and restated bank credit facility and cash on hand.

The acquisition included approximately 249,000 net acres and 2.9 Tcfe of proved reserves. The acquisition added approximately 710 MMcfe of daily average production, at the date of the acquisition, and over 1,200 net future drilling locations.

In connection with the Covey Park Acquisition, we incurred $41.0 million of advisory and legal fees and other acquisition-related costs. These acquisition costs are included in transaction costs in our consolidated statements of operations.

The transaction was accounted for as a business combination, using the acquisition method. Certain information to finalize the purchase price is not yet available, including the final tax return of Covey Park. We expect to complete the purchase price allocation within the twelve month period following the acquisition date, during which time the value of the net assets and liabilities acquired may be revised as appropriate.

As of December 31, 2019, the Jones Group owned approximately 73% of our outstanding common stock and the former owners of Covey Park owned 15%. The Jones Group and the former owners of Covey Park hold Series B and Series A Convertible Preferred Stock, respectively, that is convertible into in the aggregate of 96,250,000 shares of our common stock, if converted.

Results of Operations

Year Ended December 31, 2019 Compared to 2018 Periods

Our operating data for the period January 1, 2018 through August 13, 2018 (the "2018 Predecessor Period"), the period August 14, 2018 through December 31, 2018 (the "2018 Successor Period"), the combined Predecessor and Successor 2018 periods and the year ended December 31, 2019 are summarized below:

	Predecessor	Successor		
	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Combined Year Ended December 31, 2018(3)	Year Ended December 31, 2019
Oil and Gas Sales (in thousands):				
Natural gas sales	$147,897	$144,236	$292,133	$635,795
Oil sales	18,733	79,385	98,118	132,894
Total oil and gas sales	$166,630	$223,621	$390,251	$768,689
Net Production Data:				
Natural gas sales (MMcf)	55,240	45,031	100,271	292,834
Oil sales (MMbls)	287	1,385	1,672	2,685
Total oil and gas (MMcfe)	56,963	53,338	110,301	308,944
Average Sales Price:				
Natural gas sales	$ 2.68	$ 3.20	$ 2.91	$ 2.17
Oil sales	$ 65.23	$ 57.34	$ 58.70	$ 49.49
Total oil and gas sales	$ 2.93	$ 4.19	$ 3.54	$ 2.49
Expenses ($ per Mcfe):				
Production taxes	$ 0.06	$ 0.21	$ 0.13	$ 0.09
Gathering and transportation	$ 0.21	$ 0.20	$ 0.20	$ 0.23
Lease operating(1)	$ 0.37	$ 0.38	$ 0.39	$ 0.29
Depreciation, depletion and amortization(2)	$ 1.18	$ 1.01	$ 1.09	$ 0.89

(1) Includes ad valorem taxes.
(2) Represents depreciation, depletion and amortization of oil and gas properties only.
(3) The combined year ended December 31, 2018 information is a provided for comparative purposes only and is a non-GAAP presentation.

Oil and gas sales. Oil and gas sales of $768.7 million in 2019 increased $378.4 million or 97% over the combined Predecessor and Successor Periods for 2018 oil and gas sales of $390.3 million. The increase is due to higher production volumes that were partially offset by lower realized oil and natural gas prices in 2019. Natural gas sales increased by $343.7 million (118%) from the combined 2018 periods due primarily to the increase in production related to the Covey Park Acquisition and our 2019 drilling activities. The increased natural gas production was partially offset by a $0.74 per Mcf lower price realization from 2019 to 2018. The increase in oil sales of $34.8 million was attributable to oil production from the Bakken shale properties.

Production taxes. Production taxes of $29.2 million in 2019 increased $14.4 million or 97% from combined 2018 production taxes of $14.8 million. This increase is primarily related to the 97% increase in oil and gas sales.

Gathering and transportation. Gathering and transportation costs increased $49.0 million or 219% to $71.3 million in 2019 as compared to $22.4 million in the combined 2018 periods. This increase primarily reflects the higher natural gas production from the acquired properties and the 2019 drilling activity.

Lease operating expenses. Our lease operating expenses of $87.3 million in 2019 were $45.4 million or 108.4% higher than the combined 2018 periods lease operating expenses of $41.9 million. Operating expenses from our natural gas operations was $0.22 per Mcfe in 2019 compared with $0.29 per Mcfe for the combined 2018 periods. Operating expenses for our oil operations were $8.99 per BOE compared with $8.64 per BOE for the combined 2018 periods. The increase is mostly attributed to higher operating costs in our Bakken shale region. Total operating expenses of $0.28 per Mcfe in 2019 were 26% less than the $0.38 per Mcfe for the combined 2018 periods due to the increase in our natural gas production.

Depreciation, depletion and amortization expense ("DD&A"). DD&A for 2019 was $276.5 million or $0.90 per Mcfe. DD&A was $68.0 million or $1.18 per Mcfe for the 2018 Predecessor Period. DD&A was $53.9 million or $1.01 per Mcfe for the 2018 Successor Period. The decrease in DD&A in 2019 primarily resulted from the lower finding costs of the 2019 proved oil and gas reserve additions driven by the Covey Park Acquisition and our 2019 drilling activity.

General and administrative expenses. General and administrative expense in 2019 of $29.2 million included $4.0 million of stock-based compensation. General and administrative costs of $11.4 million and $15.7 million for the 2018 Successor Period and the 2018 Predecessor, respectively, included $1.0 million and $3.9 million for stock-based compensation, respectively. The increase in 2019 is attributable to additional employees hired as part of the Covey Park Acquisition.

Derivative financial instruments. We utilized oil and natural gas price swaps, collars, basis swaps and swaptions to manage our exposure to commodity prices and protect returns on investment from our drilling activities. We had gains on derivative financial instruments of $51.7 million during 2019, $10.5 million during the 2018 Successor Period, and $0.9 million during the 2018 Predecessor Period. Cash activity from derivative financial instruments included receipts of $52.7 million in 2019, $5.6 million of payments in the 2018 Successor Period and receipts of $2.8 million in the 2018 Predecessor Period. The following table presents our natural gas and oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

	Predecessor	Successor	
	Period from January 1, 2018 through August 13, 2018	**Period from August 14, 2018 through December 31, 2018**	**Year Ended December 31, 2019**
Average Realized Natural Gas Price:			
Natural gas, per Mcf	$ 2.68	$ 3.20	$ 2.17
Cash settlements on derivative financial instruments, per Mcf	0.05	(0.13)	0.18
Price per Mcf, including cash settlements on derivative financial instruments	$ 2.73	$ 3.07	$ 2.35
Average Realized Oil Price:			
Crude oil per Barrel	$65.23	$57.34	$49.49
Cash settlements on derivative financial instruments, per Barrel	—	0.46	0.15
Price per Barrel, including cash settlements on derivative financial instruments	$65.23	$57.80	$49.64

Interest expense. Interest expense was $161.5 million for 2019 as compared to $43.6 million for the 2018 Successor Period and $101.2 million for the 2018 Predecessor Period. Interest for 2019 includes interest payments on the 7½% senior notes (the "2025 Notes") that were assumed in the Covey Park Acquisition, our 9¾% senior notes (the "2026 Notes") and our bank credit facility. Included in interest expense was amortization of the discount on the 2025 Notes, which were valued at 71% of their par value in connection with the Covey Park Acquisition, the 2026 Notes, and the debt cost amortization associated with our outstanding debt. The non-cash interest expense for 2019 totaled $16.3 million compared with non-cash interest expense of $2.4 million for the 2018 Successor Period and $29.5 million for the 2018 Predecessor Period. Interest for the 2018 Successor Period reflects our debt refinancing transaction that closed concurrent with the Jones Contribution in which we refinanced all of our then existing debt with the issuance of $850.0 million of the 2026 Notes and $450.0 million of borrowings under a new bank credit facility.

Income taxes. Income taxes were a provision of $27.8 million in 2019, a provision of $18.9 million in the 2018 Successor Period and a provision of $1.1 million in the 2018 Predecessor Period. The effective tax rate of 22% in 2019 differed from the federal income tax rate of 21% primarily due to recognition of the effect state taxes and a tax benefit for the reduction of our valuation allowance. The effective tax rate was 23% in the 2018 Successor Period, and a benefit of 1% for the 2018 Predecessor Period. Income taxes for the 2018 Successor Period differed from the federal income tax rate primarily due to the effect of state taxes and a tax benefit for the reduction of our valuation allowance. The effective tax rate for the 2018 Predecessor Period differs from the federal tax rate primarily due to a valuation allowance recognized on deferred tax assets and state taxes.

Net income. We reported net income of $96.9 million or $0.52 per diluted share in 2019, $64.1 million or $0.61 per diluted share in the 2018 Successor Period, a net loss of $92.8 million or $6.08 per share for the 2018 Predecessor Period. The net income in the 2019 reflects higher operating profit from oil and gas operations due to the Covey Park Acquisition and our 2019 drilling activities. The net income in the 2018 Successor Period reflects higher operating profit from oil and gas operations due to the contribution of the Bakken shale properties and lower interest expense due to our debt refinancing. The loss in the 2018 Predecessor Period was mainly due to the high interest expense.

2018 Periods Compared to Year Ended December 31, 2017

Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 filed with the SEC on March 1, 2019.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings and asset sales. In 2019, our primary source of funds was operating cash flows and the issuance of common stock, preferred stock and borrowings to finance the Covey Park Acquisition. Cash provided by operating activities in 2019 was $451.2 million compared with $188.0 million of combined operating cash flows for the 2018 periods. The increase in operating cash flow during 2019 primarily reflects higher oil and gas sales resulting from the acquired Covey Park Acquisition and our 2019 drilling activities.

For the 2018 Successor Period our primary source of funds was operating cash flows and debt financings. Cash provided by operating activities for the 2018 Successor Period was $102.3 million. For the 2018 Predecessor Period our primary sources of funds was operating cash flow, proceeds from asset sales and debt financings. Cash flow from operating activities for the 2018 Predecessor Period were $85.7 million. The increase in operating cash flow during the 2018 Successor Period primarily reflects higher oil and gas sales resulting from the contributed Bakken shale properties and the growth in our natural gas production resulting from our Haynesville shale drilling activities. For the Predecessor 2017, our primary source of funds was operating cash flow.

Our capital expenditure activity is summarized in the following table:

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(in thousands)			
Property Acquisitions	$ —	$ 39,323	$ 21,013	$ 2,097,451
Exploration and development:				
Development leasehold costs	4,698	2,848	1,715	7,603
Development drilling and completion costs	164,472	90,840	148,745	493,625
Other development costs	9,644	13,871	13,612	9,339
Total exploration and development	178,814	107,559	164,072	510,567
Other	43	31	2	198
Total capital expenditures	$ 178,857	$ 107,590	$ 164,074	$ 510,765

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. We currently expect to spend approximately $421.0 million in 2020 for development and exploration projects including drilling 46 (34.3 net to us) operated horizontal wells, completing 18 (12.6 net to us) wells drilled in 2019, and for other development projects. Our operating cash flow and, therefore, our capital expenditures are highly dependent on oil and natural gas prices. We operate most of the properties where we expect ongoing development and as a result have significant discretion over the amount and timing of our future capital expenditures.

We do not have a specific acquisition budget for 2020 because the timing and size of acquisitions are unpredictable. We intend to use our cash flows from operations, borrowings under our bank credit facility, or other debt or equity financings to the extent available, to finance such acquisitions. The availability and attractiveness of these sources of financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions. Lack of access to the debt or equity markets due to general economic conditions could impede our ability to complete acquisitions.

In connection with the Jones Contribution, we completed a series of refinancing transactions to retire all of our other then-outstanding senior secured and unsecured notes. On August 3, 2018, we issued $850.0 million of 2026 Notes for net proceeds of $815.9 million. Interest on the 2026 Notes is payable on February 15 and August 15 at an annual rate of 9¾% and the 2026 Notes mature on August 15, 2026. As a part of the Covey Park Acquisition, we assumed Covey Park's $625.0 million 7½% senior notes that were outstanding. Interest on the assumed notes is payable on May 15 and November 15 at an annual rate of 7½% and these notes mature on May 15, 2025.

On August 14, 2018, we entered into a new bank credit facility with Bank of Montreal, as administrative agent, and the participating banks. The bank credit facility was subject to a borrowing base of $700.0 million which was re-determined on a semi-annual basis and upon the occurrence of certain other events. Concurrent with the closing of the Covey Park Acquisition, the bank credit facility was amended and restated to provide for a $1.575 billion borrowing base which will be re-determined on a semi-annual basis and upon the occurrence of certain other events. The maturity date was extended to July 16, 2024. The initial committed borrowing base was set at $1,500.0 million, of which $1,250.0 million of borrowings were outstanding as of December 31, 2019. The borrowing base was reaffirmed in November 2019. Borrowings under the bank credit facility are secured by substantially all of our assets and those of our subsidiaries and bear interest at our option, at either LIBOR plus 1.75% to 2.75% or a base rate plus 0.75% to 1.75%, in each case depending on the utilization of the borrowing base. We also pay a commitment fee of 0.375% to 0.5% on the unused borrowing base. The bank credit facility places certain restrictions upon our and our restricted subsidiaries' ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the senior notes. The only financial covenants are the maintenance of a leverage ratio of less than 4.0 to 1.0 and a adjusted current ratio of at least 1.0 to 1.0. The financial covenants are determined starting with the financial results for the three months ended December 31, 2019. We were in compliance with the covenants as of December 31, 2019.

The following table summarizes our aggregate liabilities and commitments by year of maturity:

	2020	2021	2022	2023	2024	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ —	$ —	$1,250,000	$ —	$1,250,000
7½% Senior Notes Due 2025	—	—	—	—	—	625,000	625,000
9¾% Senior Notes Due 2026	—	—	—	—	—	850,000	850,000
Interest	182,750	182,750	182,750	182,750	158,458	152,250	1,041,708
Operating leases	2,857	2,181	467	—	—	—	5,505
Transportation	10,714	12,031	24,822	24,822	24,890	169,617	266,896
Drilling rigs and completion	36,367	—	—	—	—	—	36,367
	$232,688	$196,962	$208,039	$207,572	$1,433,348	$1,796,867	$4,075,476

Future interest costs are based upon the effective interest rates of our outstanding senior notes and borrowings under our bank credit facility.

We have obligations to incur future payments for dismantlement, abandonment and restoration costs of oil and gas properties. These payments are currently estimated to be incurred primarily after 2023. We record a separate liability for these asset retirement obligations, which totaled $18.2 million as of December 31, 2019.

We believe that our cash on hand and cash flow from operations and available borrowings under our bank credit facility is sufficient to fund our 2020 planned drilling activities. If our plans or assumptions change or our assumptions prove to be inaccurate, we may be required to seek additional capital, including additional equity or debt financings to replace any liquidity that may be lost from low oil and natural gas prices. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

Federal and State Taxation

The Tax Cuts and Jobs Act, which was enacted on December 22, 2017, reduced the corporate income tax rate effective January l, 2018 from 35% to 21%. Among the other significant tax law changes that potentially affect us are the elimination of the corporate alternative minimum tax ("AMT"), changes that require operating losses incurred in 2018 and beyond be carried forward indefinitely with no carryback up to 80% of taxable income in a given year, and limitations on the deduction for interest expense incurred in 2018 or later of up to 30% of its adjusted taxable income (defined as taxable income before interest and net operating losses) for the taxable year. For the tax years beginning before January 1, 2022, the adjusted taxable income for these purposes is also adjusted to exclude the impact of depreciation, depletion and amortization. The Tax Cuts and Jobs Act preserved deductibility of intangible drilling costs for federal income tax purposes, which allows us to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income. At December 31, 2018, we completed the accounting for the tax effects of enactment of the Tax Cuts and Jobs Act. We remeasured certain deferred federal tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21%. The amount recognized related to the remeasurement of our deferred federal tax balance was $140.4 million in 2018, which was subject to a valuation allowance. The Tax Cuts and Jobs Act repealed the AMT for tax years beginning on or after January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset federal taxes for any taxable year. In addition, 50% of any unused AMT credit carryforwards can be refunded during tax years 2018 through 2020. We had $20.4 million of unused AMT credit carryforwards at December 31, 2018, of which $10.2 million was refunded during 2019.

At December 31, 2019, we had $0.9 billion in U.S. federal net operating loss carryforwards and $1.5 billion in certain state net operating loss carryforwards. The shares of common stock issued as a result of the Jones Contribution triggered an ownership change under Section 382 of the Internal Revenue Code. As a result, our ability to use net operating losses ("NOLs") to reduce taxable income is generally limited to an annual amount based on the fair market value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. Our NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of our common stock immediately prior to the ownership change, we believe that we have a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period.

The shares of our common stock issued in connection with the Covey Park Acquisition did not trigger another ownership change under Section 382. As a result, no additional NOL limitations are expected.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carryforwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire. NOLs generated in 2018 and after would be carried forward indefinitely. Our use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If we do not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then we will lose the ability to apply those NOLs as offsets to future taxable income. We estimate that $840.4 million of the U.S. federal NOL carryforwards and $1.4 billion of the estimated state NOL carryforwards will expire unused.

Our federal income tax returns for the years subsequent to December 31, 2015 remain subject to examination. Our income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2016. We currently believe that our significant filing positions are highly certain and that all of our other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on our consolidated financial statements. Therefore, we have not established any significant reserves for uncertain tax positions.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses.

Successful efforts accounting. We are required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and natural gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

Oil and natural gas reserve quantities. The determination of depreciation, depletion and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. The determination of whether impairments should be recognized on our oil and gas properties is also dependent on these estimates, as well as estimates of probable reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities and timing of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our future prospects and the value of our common stock.

Impairment of oil and gas properties. We evaluate our proved properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserves estimates at the end of the period. The estimated future cash flows that we use in our assessment of the need for an impairment are based on a corporate forecast which considers forecasts from multiple independent price forecasts. Prices are not escalated to levels that exceed observed historical market prices. Costs are also assumed to escalate at a rate that is based on our historical experience, currently estimated at 2% per annum. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of the average first day of the month historical price for the year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of our oil and gas leases. It is reasonably possible that our estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be impairments in the carrying values of our proved and unproved oil and gas properties in the future.

Goodwill. We have goodwill of $335.9 million as of December 31, 2019 that was recorded in connection with the Jones Contribution. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets. We are not required to amortize goodwill as a charge to earnings; however, we are required to conduct an annual review of goodwill for impairment.

We determine the potential for impairment of our goodwill by initially preparing a qualitative fair value assessment of our business value. In performing this qualitative assessment, we examine relevant events and circumstances that could have a negative effect on our business, including macroeconomic conditions, industry and market conditions (including current commodity price), earnings and cash flows, overall financial performance and other relevant entity specific events.

If the qualitative assessment indicates that it is more likely than not that our business is impaired, a quantitative analysis would be performed to assess our fair value and to determine the amount of impairment, if any, that requires recognition. When performing a quantitative impairment assessment of goodwill, fair value is determined based on a combination of (i) recent market transactions, where available; and (ii) projected discounted cash flows (an income approach). Under the market approach, fair value would be estimated by a comparison to similar businesses whose securities are actively traded in the public market. This requires our management to make certain judgments, including the selection of comparable companies, comparable recent company asset transactions, transaction premiums and selected financial metrics. Under the income approach, fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenues, estimates of future operating, administrative and capital costs adjusted for inflation, projected reserves quantities, the probability of success for future exploration for and development of proved and unproved reserves, discount rates and other variables. Future cash flows are discounted using discount factors applied by us when assessing oil and gas acquisition opportunities and we believe provide a fair market value of our business. Negative revisions of estimated reserves quantities, sustained decreases in crude oil or natural gas prices, increases in future cost estimates, or divestitures could lead to reductions in expected future cash flows that would indicate potential impairment of all or a portion of goodwill in future periods.

If the carrying value of goodwill exceeds the fair value calculated using the quantitative approach, an impairment charge would be recorded for the difference between fair value and carrying value. If oil or natural gas prices decrease, drilling efforts are unsuccessful or our market capitalization declines, it is reasonably possible that impairments would need to be recognized. We performed our assessment of goodwill as of October 31, 2019 and determined there were no indicators of impairment.

Income Taxes. We account for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

In recording deferred income tax assets, we consider whether it is more likely than not that some portion or all of our deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. We believe that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, we are not able to determine that it is more likely than not that all of our deferred tax assets will be realized. As a result, we established valuation allowances for our deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. We will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future reporting periods.

Stock-based compensation. We follow the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Recent accounting pronouncements. In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04) "Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." ASU 2017-04 eliminates step two of the goodwill impairment test and specifies that goodwill impairment should be measured by comparing the fair value of a reporting unit with its carrying amount. ASU 2017-04 is effective for annual or interim goodwill impairment tests performed in fiscal years beginning after December 15, 2019 and early adoption is permitted. We did not early adopt ASU 2017-04 and will implement ASU 2017-04 on our financial statements when we perform annual impairment assessments following adoption of this standard in 2020. We do not expect the update to have a significant effect on our results of operations, liquidity or financial position.

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 requires lessees to include most leases on their balance sheets, but recognize lease costs in their financial statements in a manner similar to accounting for leases prior to ASC 2016-02. ASU 2016-02 is effective for annual periods ending after December 15, 2018 and interim periods thereafter. We adopted ASC 2016-02 beginning January 1, 2019. We used the modified retrospective method of adoption for this new standard and are utilizing certain practical expedients as part of our adoption. The adoption of ASC 2016-02 did not have a significant effect on our results of operations, liquidity or financial position.

In June 2016, The FASB issued Accounting Standards Update ASU No. 2016-13 ("ASU 2016-13") that amends guidance on reporting credit losses for trade receivables, net investments in leases, debt securities, loans and certain other instruments. ASU 2016-13 requires the use of a forward-looking expected loss model as opposed to existing incurred loss recognition. The update is effective for us beginning in 2020. The guidance requires a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the standard is effective. We are continuing to evaluate the provisions of this update, but we currently do not expect it will have a material impact on our results of operations, financial position and financial disclosures.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Based on our oil and natural gas production in 2019 and taking into account any oil or natural gas price swap agreements we had in place, a $1.00 change in the price per barrel of oil would have resulted in a change in our cash flow for such period by approximately $2.6 million and a $0.10 change in the price per Mcf of natural gas would have changed our cash flow by approximately $20.2 million.

As of December 31, 2019, we have entered into natural gas price swap agreements to hedge approximately 138.3 Bcf of our 2020 through 2022 production at an average price of $2.81 per Mcf. We have also entered into two-way natural gas collars to hedge approximately 16.4 Bcf of natural gas with an average floor price of $2.47 per Mcf and an average ceiling price of $3.46 per Mcf. We also have two-way oil collars to hedge 1,262,600 barrels with an average floor price of $48.65 per barrel and an average ceiling price of $64.92 per barrel. We have three-way collars to hedge 26.5 Bcf of natural gas with an average floor price of $2.65 per Mcf, an average ceiling price of $2.99 per Mcf and an average put price of $2.33. We have entered into natural gas swaptions which hedge 65.8 Bcf of natural gas, with an additional 76.7 Bcf subject to option exercises, at an average price of $2.52 per Mcf. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. The change in the fair value of our natural gas swaps that would result from a 10% change in commodities prices at December 31, 2019 would be $33.7 million. Such a change in fair value could be a gain or a loss depending on whether prices increase or decrease. Since December 31, 2019, we have entered into additional natural gas swaptions which hedge an additional 28.0 Bcf of natural gas to be produced from February 2020 to December 2021, with an additional 43.8 Bcf to be produced from January 2021 to December 2022, subject to option exercises, at an average price of $2.51 per Mcf.

Interest Rates

At December 31, 2019, we had approximately $2.7 billion principal amount of long-term debt outstanding. The 2026 Notes of which $850.0 million was outstanding at December 31, 2019 bear interest at a fixed rate of 9¾%. The 2025 Notes of which $625.0 million was outstanding at December 31, 2019 bear interest at a fixed rate of 7½%. The fair market value of the 2026 Notes and 2025 Notes as of December 31, 2019 was $765.0 million and $534.4 million, respectively, based on the market price of approximately 90% and 85.5% of the face amount of such debt. At December 31, 2019, we had $1,250 million outstanding under our bank credit facility, which is subject to variable rates of interest that are tied to LIBOR or the corporate base rate, at our option. Any increase in these interest rates would have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at December 31, 2019, a 100 basis point change in interest rates would change our interest expense on our variable rate debt by approximately $12.5 million.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our consolidated financial statements are included on pages F-1 to F-42 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

Our registered independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is comprised of three directors who are not our employees. This committee meets periodically with our independent public accountants and management. Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Controls and Procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are designed to provide reasonable assurance that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2019. The evaluation was performed with the participation of senior management of each business segment and key corporate functions, and under the supervision of the Chief Executive Officer and Chief Financial Officer.

Based on our evaluation of our disclosure controls and procedures, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2019 to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2019 that materially affected or are reasonably likely to materially affect our internal control over financial reporting. We are in the process of integrating the Covey Park Energy operations into the control environment, including internal controls over financial reporting.

Management's Report on Internal Control over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, we conducted an assessment, including testing, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Our system of internal control over financial reporting is 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. 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. As of December 31, 2019, we assessed the effectiveness of the Company's internal control over financial reporting based on the COSO criteria, and based on that assessment we determined that the Company maintained effective internal control over financial reporting as of December 31, 2019. On July 16, 2019, we completed the acquisition of Covey Park Energy LLC. We are in the process of integrating Covey Park Energy LLC's operations, and, therefore, management's evaluation and conclusion as to the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report on Form 10-K excludes any evaluation of internal control over financial reporting of the Covey Park Energy LLC business. Covey Park Energy LLC accounted for approximately 48% of the Company's total assets and 34% of total revenues of the Company as of and for the year ended December 31, 2019.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, follows below.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
Comstock Resources, Inc.

Opinion on Internal Control over Financial Reporting

We have audited Comstock Resources, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Comstock Resources, Inc. and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Covey Park Energy LLC, which is included in the 2019 consolidated financial statements of the Company and constituted 48% of total assets as of December 31, 2019 and 34% of total revenues, for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Covey Park Energy LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2019, the related consolidated statements of operations, stockholders' equity and cash flows for the year ended December 31, 2017 (Predecessor), the period from January 1, 2018 through August 13, 2018 (Predecessor), the period from August 14, 2018 through December 31, 2018 (Successor), and the year ended December 31, 2019 and the related notes and our report dated March 2, 2020 expressed an unqualified opinion thereon.

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 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/ ERNST & YOUNG LLP

Dallas, Texas
March 2, 2020

ITEM 9B. *OTHER INFORMATION*

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required by this item is incorporated herein by reference to “Business – Directors and Executive Officers” in this Form 10-K and to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2019.

Section 16(a) Beneficial Ownership Reporting Compliance. Our directors, executive officers and stockholders with ownership of 10% or greater are required, under Section 16(a) of the Securities Exchange Act of 1934, to file reports of their ownership and changes to their ownership of our securities with the SEC. Based solely on our review of the reports and any written representations we received that no other reports were required, we believe that, during the year ended December 31, 2019, all of our officers, directors and stockholders with ownership of 10% or greater complied with all Section 16(a) filing requirements applicable to them.

Code of Ethics. We have adopted a Code of Business Conduct and Ethics that is applicable to all of our directors, officers and employees as required by New York Stock Exchange rules. We have also adopted a Code of Ethics for Senior Financial Officers that is applicable to our Chief Executive Officer and Senior Financial Officers. Both the Code of Business Conduct and Ethics and Code of Ethics for Senior Financial Officers may be found on our website at www.comstockresources.com. Both of these documents are also available, without charge, to any stockholder upon request to: Comstock Resources, Inc., Attn: Investor Relations, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (972) 668-8800. We intend to disclose any amendments or waivers to these codes that apply to our Chief Executive Officer and senior financial officers on our website in accordance with applicable SEC rules. Please see the definitive proxy statement for our 2020 annual meeting, which will be filed with the SEC within 120 days of December 31, 2019, for additional information regarding our corporate governance policies.

ITEM 11. *EXECUTIVE COMPENSATION*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2019.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2019:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Number of securities authorized for future issuance under equity compensation plans (excluding outstanding options, warrants and rights)
Equity compensation plans approved by stockholders	1,863,780[1]	5,501,598

(1) Represents performance share unit awards that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.

We do not have any equity compensation plans that were not approved by stockholders.

Further information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2019.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2019.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2019.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements:

1. The following consolidated financial statements and notes of Comstock Resources, Inc. are included on Pages F-2 to F-42 of this report:

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) Exhibits:

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
2.1	Contribution Agreement dated May 9, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K/A dated May 9, 2018).
2.2	Amendment No. 1 to the Contribution Agreement, dated as of August 14, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated August 13, 2018).
2.3	Agreement and Plan of Merger, dated June 7, 2019, by and among the Company, Covey Park Energy LLC, New Covey Park Energy LLC and Covey Park Energy Holdings LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated June 7, 2019).
2.4	First Amendment to Agreement and Plan of Merger dated as of July 15, 2019 by and among the Company, New Covey Park Energy LLC, Covey Park Energy LLC and Covey Park Energy Holdings LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 15, 2019).
3.1	Second Amended and Restated Articles of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 13, 2018).
3.2	Amendment to Second Amended and Restated Articles of Incorporation of the Company, dated July 16, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 15, 2019).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 21, 2014).
3.4	First Amendment to Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 17, 2018).
3.5	Amendment No. 2 to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 15, 2019).
4.1	Indenture, dated as of August 3, 2018, by and between Comstock Escrow Corporation, as issuer, and American Stock Transfer & Trust Company LLC, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated August 3, 2018).
4.2	First Supplemental Indenture dated August 14, 2018 among the Company, the Guarantors and American Stock Transfer & Trust Company, LLC, as Trustee (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated August 13, 2018).
4.3	Supplemental Indenture dated July 16, 2019 among the Company and Wells Fargo Bank, National Association for the 7½% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated July 15, 2019).
4.4	Supplemental Indenture dated July 16, 2019 among the Company, the Guaranteeing Subsidiaries and Wells Fargo Bank, National Association for the 7½% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 15, 2019).
4.5	Supplemental Indenture dated July 16, 2019 among the Company, the Guarantors and American Stock Transfer & Trust Company, LLC for the 9¾% Senior Notes due 2026 (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K dated July 15, 2019).

Exhibit No.	Description
4.6	Certificate of Designations of Series A Redeemable Convertible Preferred Stock and Series B Redeemable Convertible Preferred Stock (incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K dated July 15, 2019).
4.7	Indenture dated May 3, 2017 between Covey Park Energy LLC, Covey Park Finance Corp. and Wells Fargo Bank National Association, as Trustee, for the 7½% Senior Notes due 2025 (incorporated by reference to Exhibit 4.7 to our Quarterly Report on Form 10-Q dated August 9, 2019).
4.8	Instrument of Resignation, Appointment and Acceptance dated as of July 16, 2019 among the Company, the Subsidiary Guarantors named therein, Wells Fargo Bank, N.A. and American Stock Transfer & Trust Company LLC (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated July 15, 2019).
4.9	Shareholders Agreement, dated June 7, 2019, by and among the Company, Arkoma Drilling CP, LLC, Williston Drilling CP, LLC, Arkoma Drilling, L.P., Williston Drilling, L.P., New Covey Park Energy LLC and Jerral W. Jones (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated June 10, 2019).
4.10*	Description of Securities.
10.1	Amended and Restated Credit Agreement dated as of July 16, 2019, among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time. (incorporated by reference to Exhibit 10.2 to our Current Report on From 8-K dated July 15, 2019).
10.2*	Borrowing Base Redetermination Agreement and First Amendment to the Amended and Restated Credit Agreement, dated as of November 26, 2019, by and among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time.
10.3	Amended and Restated Registration Rights Agreement, dated June 7, 2019, by and among the Company, Arkoma Drilling, L.P., Williston Drilling, L.P., Arkoma Drilling CP, LLC, Williston Drilling CP, LLC, New Covey Park Energy LLC and Jerral W. Jones (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated June 7, 2019).
10.4*	Amendment No. 1 to the Amended and Restated Registration Rights Agreement, dated December 17, 2019, by and among the Company, Arkoma Drilling, L.P., Williston Drilling, L.P. and New Covey Park Energy LLC.
10.5#	Comstock Resources, Inc. 2019 Long-term Incentive Plan Effective as of May 31, 2019 (incorporated by reference to Exhibit 99 to our Registration Statement on Form S-8 dated June 4, 2019).
10.6#	Employment Agreement dated September 7, 2018 by and between the Company and M. Jay Allison (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 7, 2018).
10.7#	Employment Agreement dated September 7, 2018 by and between the Company and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 7, 2018).
10.8#*	Employment Agreement dated June 22, 2013 by and between the Company (as successor in interest to Covey Park) and David Terry.
10.9#*	Employment Agreement dated April 18, 2019 by and between the Company (as successor in interest to Covey Park) and Mark Wilson.
10.10	Lease between Stonebriar I Office Partners, Ltd., and Comstock Resources, Inc. dated May 6, 2004 (incorporated by reference to Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 2004).

Exhibit No.	Description
10.11	First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.12	Second Amendment to the Lease Agreement dated October 15, 2007 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.13	Third Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.11 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.14	Fourth Amendment to the Lease Agreement dated May 8, 2009 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10.15	Fifth Amendment to the Lease Agreement dated June 15, 2011 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers Lee Keeling and Associates, Inc.
23.3*	Consent of Independent Petroleum Engineers Netherland, Sewell & Associates, Inc.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Lee Keeling and Associates, Inc. on Proved Reserves as of December 31, 2019.
99.2*	Report of Netherland, Sewell & Associates, Inc. on Proved Reserves as of December 31, 2019.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith.
\+ Furnished herewith.
\# Management contract or compensatory plan document.

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.

COMSTOCK RESOURCES, INC.

By: /s/ M. JAY ALLISON
M. Jay Allison
Chief Executive Officer
(Principal Executive Officer)

Date: March 2, 2020

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/ M. JAY ALLISON M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	March 2, 2020
/s/ ROLAND O. BURNS Roland O. Burns	President, Chief Financial Officer, Secretary and Director (Principal Financial and Accounting Officer)	March 2, 2020
/s/ ELIZABETH B. DAVIS Elizabeth B. Davis	Director	March 2, 2020
/s/ MORRIS E. FOSTER Morris E. Foster	Director	March 2, 2020
/s/ JIM L. TURNER Jim L. Turner	Director	March 2, 2020
/s/ JOHN D. JACOBI John D. Jacobi	Director	March 2, 2020
/s/ JORDAN T. MARYE Jordan T. Marye	Director	March 2, 2020

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

FINANCIAL STATEMENTS

INDEX

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Comstock Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2019, the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2017 (Predecessor), the period from January 1, 2018 through August 13, 2018 (Predecessor), the period from August 14, 2018 through December 31, 2018 (Successor), and the year ended December 31, 2019 (Successor), and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2018 and 2019, and the results of its operations and its cash flows for the year ended December 31, 2017 (Predecessor), the period from January 1, 2018 through August 13, 2018 (Predecessor), the period from August 14, 2018 through December 31, 2018 (Successor), and the year ended December 31, 2019 (Successor), in conformity with U.S. generally accepted accounting principles.

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 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 2, 2020 expressed an unqualified opinion thereon.

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 regarding 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/ ERNST & YOUNG LLP

We have served as the Company's auditor since 2003.
Dallas, Texas
March 2, 2020

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
As of December 31, 2018 and 2019

	Successor	
	December 31, 2018	December 31, 2019
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	$ 23,193	$ 18,532
Accounts Receivable:		
Oil and gas sales	87,611	120,111
Joint interest operations	9,175	24,761
From affiliates	—	35,469
Derivative Financial Instruments	15,401	75,304
Income Taxes Receivable	10,218	5,109
Other Current Assets	13,829	10,399
Total current assets	159,427	289,685
Property and Equipment:		
Oil and natural gas properties, successful efforts method:		
Proved properties	1,682,164	4,077,513
Unproved properties	191,929	410,897
Other property and equipment	4,442	6,866
Accumulated depreciation, depletion and amortization	(210,556)	(486,473)
Net property and equipment	1,667,979	4,008,803
Goodwill	350,214	335,897
Income Taxes Receivable	10,218	5,109
Derivative Financial Instruments	—	13,888
Operating Lease Right-of-Use Assets	—	3,509
Other Assets	2	231
	$2,187,840	$4,657,122
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts Payable	$ 138,767	$ 252,994
Accrued Expenses	68,086	137,166
Operating Leases	—	1,994
Derivative Financial Instruments	—	222
Total current liabilities	206,853	392,376
Long-term Debt	1,244,363	2,500,132
Deferred Income Taxes	161,917	211,772
Derivative Financial Instruments	—	4,220
Long-term Operating Leases	—	1,515
Reserve for Future Abandonment Costs	5,136	18,151
Other Non-current Liabilities	—	6,351
Total liabilities	1,618,269	3,134,517
Commitments and Contingencies		
Mezzanine Equity:		
Preferred Stock—5,000,000 shares authorized, 385,000 shares issued and outstanding at December 31, 2019:		
Series A 10% Convertible Preferred Stock, 210,000 shares issued and outstanding	—	204,583
Series B 10% Convertible Preferred Stock, 175,000 shares issued and outstanding	—	175,000
Stockholders' Equity:		
Common stock—$0.50 par, 155,000,000 and 400,000,000 shares authorized, 105,871,064 and 190,006,776 shares issued and outstanding at December 31, 2018 and December 31, 2019, respectively	52,936	95,003
Additional paid-in capital	452,513	909,423
Accumulated earnings	64,122	138,596
Total stockholders' equity	569,571	1,143,022
	$2,187,840	$4,657,122

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Predecessor		Successor	
	Years Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands, except per share amounts)			
Natural gas sales	$ 208,741	$ 147,897	$144,236	$ 635,795
Oil sales	46,590	18,733	79,385	132,894
Total oil and gas sales	255,331	166,630	223,621	768,689
Operating expenses:				
Production taxes	5,373	3,659	11,155	29,181
Gathering and transportation	17,538	11,841	10,511	71,303
Lease operating	37,859	21,139	20,736	87,283
Exploration	—	—	—	241
Depreciation, depletion and amortization	123,557	68,032	53,944	276,526
General and administrative, net	26,137	15,699	11,399	29,244
Impairment of oil and gas properties	43,990	—	—	—
Loss (gain) on sale of oil and gas properties	1,060	35,438	(155)	25
Total operating expenses	255,514	155,808	107,590	493,803
Operating income (loss)	(183)	10,822	116,031	274,886
Other income (expenses):				
Gain from derivative financial instruments	16,753	881	10,465	51,735
Other income	530	677	173	622
Transaction costs	—	(2,866)	—	(41,010)
Interest expense	(146,449)	(101,203)	(43,603)	(161,541)
Total other income (expenses)	(129,166)	(102,511)	(32,965)	(150,194)
Income (loss) before income taxes	(129,349)	(91,689)	83,066	124,692
(Provision for) benefit from income taxes	17,944	(1,065)	(18,944)	(27,803)
Net income (loss)	(111,405)	(92,754)	64,122	96,889
Preferred stock dividends and accretion	—	—	—	(22,415)
Net income (loss) available to common stockholders	$(111,405)	$ (92,754)	$ 64,122	$ 74,474
Net income (loss) per share – basic and diluted	$ (7.61)	$ (6.08)	$ 0.61	$ 0.52
Weighted average shares outstanding:				
Basic	14,644	15,262	105,453	142,750
Diluted	14,644	15,262	105,459	187,378

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Shares	Common Stock-Par Value	Common Stock Warrants	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
			(In thousands)			
Predecessor Company:						
Balance at December 31, 2016	13,938	$ 6,969	$ 5,672	$ 531,924	$ (815,834)	$ (271,269)
Stock-based compensation	451	225	—	5,698	—	5,923
Income tax withholdings related to equity awards	(34)	(16)	—	(296)	—	(312)
Common stock issued for debt conversion	826	412	—	7,377	—	7,789
Common stock warrants exercised	247	124	(2,115)	1,993	—	2
Net loss	—	—	—	—	(111,405)	(111,405)
Balance at December 31, 2017	15,428	$ 7,714	$ 3,557	$ 546,696	$ (927,239)	$ (369,272)
Stock-based compensation	623	311	—	3,601	—	3,912
Income tax withholdings related to equity awards	(53)	(26)	—	(343)	—	(369)
Common stock issued for debt conversion	2	1	—	28	—	29
Common stock warrants exercised	379	189	(3,247)	3,058	—	—
Net loss	—	—	—	—	(92,754)	(92,754)
Balance at August 13, 2018	16,379	$ 8,189	$ 310	$ 553,040	$(1,019,993)	$ (458,454)
Successor Company:						
Balance at August 13, 2018	16,379	$ 8,189	$ 310	$ 132,032	$ —	$ 140,531
Jones contribution	88,571	44,286	—	315,902	—	360,188
Vesting of equity awards	1,029	514	—	8,312	—	8,826
Income tax withholdings related to equity awards	(547)	(272)	—	(4,423)	—	(4,695)
Stock-based compensation	415	207	—	787	—	994
Stock issuance costs	—	—	—	(395)	—	(395)
Common stock warrants exercised and expired	24	12	(310)	298	—	—
Net income	—	—	—	—	64,122	64,122
Balance at December 31, 2018	105,871	$ 52,936	$ —	$ 452,513	$ 64,122	$ 569,571
Jones contribution adjustment	—	—	—	(1,969)	—	(1,969)
Stock-based compensation	841	420	—	3,600	—	4,020
Issuance of common stock	83,333	41,666	—	456,967	—	498,633
Income tax withholdings related to equity awards	(38)	(19)	—	(201)	—	(220)
Equity issuance costs	—	—	—	(1,487)	—	(1,487)
Net income	—	—	—	—	96,889	96,889
Preferred dividend accretion	—	—	—	—	(4,583)	(4,583)
Payment of preferred dividends	—	—	—	—	(17,832)	(17,832)
Balance at December 31, 2019	190,007	$ 95,003	$ —	$ 909,423	$ 138,596	$ 1,143,022

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ (111,405)	$ (92,754)	$ 64,122	$ 96,889
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Deferred and non-current income taxes	(18,080)	1,052	29,079	28,026
Loss (gain) on sale of oil and gas properties	1,060	35,438	(155)	25
Impairment of oil and gas properties	43,990	—	—	—
Depreciation, depletion and amortization	123,557	68,032	53,944	276,526
Gain on derivative financial instruments	(16,753)	(881)	(10,465)	(51,735)
Cash settlements of derivative financial instruments	9,405	2,842	(5,579)	52,684
Amortization of debt discount, premium and issuance costs	35,880	29,457	2,404	16,274
Interest paid in-kind	38,073	25,004	—	—
Stock-based compensation	5,923	3,912	994	4,020
Decrease (increase) in accounts receivable	(16,128)	2,834	(61,048)	3,220
Decrease (increase) in other current assets	(921)	337	(12,527)	9,823
Increase in accounts payable and accrued expenses	80,013	10,462	41,533	15,485
Net cash provided by operating activities	174,614	85,735	102,302	451,237
CASH FLOWS FROM INVESTING ACTIVITIES:				
Acquisition of Covey Park Energy LLC, net of cash acquired	—	—	—	(693,869)
Capital expenditures	(180,481)	(150,106)	(169,786)	(486,781)
Advance payments for drilling costs	—	(3,692)	(5,644)	9,336
Proceeds from sales of oil and gas properties	1,528	103,593	13,796	475
Net cash used for investing activities	(178,953)	(50,205)	(161,634)	(1,170,839)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Borrowings	8,000	865,577	450,000	927,000
Payments to retire debt	(8,000)	(49,679)	(1,291,352)	(127,000)
Repayment of Covey Park Energy LLC obligations	—	—	—	(533,390)
Issuance of common stock	—	—	—	300,000
Issuance of Series B Convertible Preferred Stock	—	—	—	175,000
Preferred stock dividends paid	—	—	—	(17,832)
Jones contribution	—	—	40,736	—
Debt and equity issuance costs	—	(18,127)	(6,351)	(8,617)
Income tax withholdings related to equity awards	(312)	(369)	(4,695)	(220)
Common stock warrants exercised	2	—	—	—
Net cash provided by (used for) financing activities	(310)	797,402	(811,662)	714,941
Net increase (decrease) in cash and cash equivalents	(4,649)	832,932	(870,994)	(4,661)
Cash and cash equivalents, beginning of the year	65,904	61,255	894,187	23,193
Cash and cash equivalents, end of the year	$ 61,255	$ 894,187	$ 23,193	$ 18,532

The accompanying notes are an integral part of these statements.

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. and subsidiaries reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock Resources, Inc. and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of oil and natural gas properties. The Company's operations are primarily focused in Texas, Louisiana and North Dakota. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements. Net income (loss) and comprehensive income (loss) are the same in all periods presented.

Jones Contribution

On August 14, 2018, Arkoma Drilling, L.P. and Williston Drilling, L.P. (collectively, the "Jones Partnerships") contributed certain oil and gas properties in North Dakota and Montana (the "Bakken Shale Properties") in exchange for 88,571,429 newly issued shares of common stock representing 84% of the Company's then outstanding common stock (the "Jones Contribution"). The Jones Partnerships are wholly owned and controlled by Dallas businessman Jerry Jones and his children (collectively, the "Jones Group").

The Company assessed the Bakken Shale Properties to determine whether they meet the definition of a business under US generally accepted accounting principles, determining that they do not meet the definition of a business. As a result, the Jones Contribution is not being accounted for as a business combination. Upon the issuance of the shares of Comstock common stock, the Jones Group obtained control over Comstock through their ownership of the Jones Partnerships. Through the Jones Partnerships, the Jones Group owns a majority of the voting common stock as well as the ability to control the composition of the majority of the board of directors of Comstock. As a result of the change of control that occurred upon the issuance of the common stock, the Jones Group controls Comstock and, thereby, continues to control the Bakken Shale Properties.

Accordingly, the basis of the Bakken Shale Properties recognized by Comstock is the historical basis of the Jones Group. The historical cost basis of the Bakken Shale properties contributed was $397.6 million, which was comprised of $554.3 million of capitalized costs less $156.7 million of accumulated depletion, depreciation and amortization. The change in control of Comstock resulted in a new basis for Comstock and the Company elected to apply pushdown accounting pursuant to ASC 805, Business Combinations. The new basis was pushed down to Comstock for financial reporting purposes, resulting in Comstock's assets, liabilities and equity accounts being recognized at fair value upon the closing of the Jones Contribution.

References to "Successor" or "Successor Company" relate to the financial position and results of operations of the Company subsequent to August 13, 2018. Reference to "Predecessor" or "Predecessor Company" relate to the financial position and results of operations of the Company on or prior to

August 13, 2018. The Company's consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after August 13, 2018 and dates prior thereto.

The following table represents the allocation of fair value related to the assets acquired and the liabilities assumed after giving consideration for final purchase accounting adjustments based on the fair value of Comstock:

	(In thousands)
Consideration:	
Fair Value of Common Stock Issued	$ 149,357
Liabilities Assumed:	
Current Liabilities	180,452
Long-Term Debt	2,059,560
Deferred Income Taxes	49,391
Reserve for Future Abandonment Costs	4,440
Liabilities Assumed	2,293,843
Total Consideration and Liabilities Assumed	$2,443,200
Assets Acquired:	
Current Assets	936,026
Oil and Gas Properties	1,147,749
Other Property & Equipment	4,440
Income Taxes Receivable	19,086
Other Assets	2
Total Assets Acquired	2,107,303
Goodwill	$ 335,897

The goodwill that was recognized was primarily attributable to the excess of the fair value of Comstock's common stock over the identifiable assets acquired net of liabilities assumed, measured in accordance with generally accepted accounting principles in the United States. The fair value of oil and gas properties, a Level 3 measurement, was determined using discounted cash flow valuation methodology. Key inputs to the valuation included average oil prices of $79.72 per barrel, average natural gas prices of $3.87 per thousand cubic feet and discount rates of 10% - 25%, based on reserve classification. The combination of the Bakken Shale Properties with Comstock's Haynesville shale properties resulted in a Company with adequate resources and liquidity to fully exploit its Haynesville/ Bossier shale asset base and to continue to expand its opportunity with future drilling, acquisitions and leasing activity in the basin.

Covey Park Acquisition

On July 16, 2019, Comstock acquired Covey Park Energy LLC ("Covey Park") for total consideration of $700.0 million of cash, the issuance of Series A Convertible Preferred Stock with a redemption value of $210.0 million, and the issuance of 28,833,000 shares of common stock (the "Covey Park Acquisition"). In addition to the consideration paid, Comstock assumed $625.0 million of Covey Park's 7.5% senior notes, repaid $380.0 million of Covey Park's then outstanding borrowings under its bank credit facility and redeemed all of Covey Park's preferred equity for $153.4 million. Based on the fair value of the preferred stock issued and the closing price of the Company's common stock of $5.82 per share on July 16, 2019, the transaction was valued at approximately $2.2 billion. Covey Park's operations were focused primarily in the Haynesville / Bossier shale in East Texas and North Louisiana.

Funding for the Covey Park Acquisition was provided by the sale of 50.0 million newly issued shares of common stock for $300.0 million and 175,000 shares of newly issued Series B Convertible Preferred Stock for $175.0 million to the Company's majority stockholder and by borrowings under Comstock's amended and restated bank credit facility and cash on hand.

As of December 31, 2019, the Jones Group owned approximately 73% of the Company's outstanding common stock and the former owners of Covey Park owned 15%. The Jones Group and the former owners of Covey Park hold Series B and Series A Convertible Preferred Stock, respectively, that is convertible into in the aggregate 96,250,000 shares of the Company's common stock.

In connection with the Covey Park Acquisition, Comstock incurred $41.0 million of advisory and legal fees and other acquisition-related costs. These acquisition costs are included in transaction costs in the Company's consolidated statements of operations.

The transaction was accounted for as a business combination, using the acquisition method. Certain information to finalize the purchase price is not yet available, including the final tax return of Covey Park. The Company expects to complete the purchase price allocation within the twelve month period following the acquisition date, during which time the value of the net assets and liabilities acquired may be revised as appropriate. The following table presents the Company's preliminary purchase price allocation of the assets acquired and liabilities assumed based on their fair values as of the acquisition date:

	(In thousands)
Consideration:	
Cash Paid	$ 700,000
Fair Value of Common Stock Issued	167,808
Fair Value of Series A Preferred Stock Issued	200,000
Total Consideration	1,067,808
Liabilities Assumed:	
Accounts Payable and Accrued Liabilities	129,622
Derivative Financial Instruments	388
Other Current Liabilities	9,930
Long Term Debt	826,625
Covey Park Preferred Equity	153,390
Non-current Derivative Financial Instruments	186
Asset Retirement Obligations	5,374
Deferred Income Taxes	23,466
Other Non-current Liabilities	9,893
Liabilities Assumed	1,158,874
Total Consideration and Liabilities Assumed	$2,226,682

	(In thousands)
Assets Acquired:	
Cash and Cash Equivalents	$ 6,131
Accounts Receivable	86,285
Current Derivative Financial Instruments	51,004
Other Current Assets	5,511
Proved Oil and Natural Gas Properties	1,818,413
Unproved Oil and Natural Gas Properties	237,210
Other Property, Plant and Equipment	2,262
Non-current Derivative Financial Instruments	19,866
Total Assets Acquired	$2,226,682

The Series A Convertible Preferred Stock was issued with a face value of $210.0 million. Management retained a third-party valuation firm to assess the fair value of the preferred stock. A yield methodology using Level 2 inputs of the Company's publicly traded debt, including the assumption of Covey Park's 7.5% senior notes, resulted in a fair value of $200.0 million.

The fair values determined for accounts receivable, accounts payable, accrued drilling costs and other current liabilities were equivalent to the carrying value due to their short-term nature.

The fair value of the proved and unproved oil and natural gas properties was derived from estimated future discounted net cash flows, a Level 3 measurement, based on existing production curves and timing of development of those properties. The key factors used in deriving the estimated future cash flows include estimated recoverable reserves, production rates, future operating and development costs, and future commodity prices. Key inputs to the valuation included average oil prices of $74.80 per barrel and average natural gas prices of $3.32 per Mcf utilizing a combination of third-party price estimates and management price forecasts as of the acquisition date. The resulting estimated future cash flows from the acquired assets were discounted at rates ranging from 10% - 25% depending on risk characteristics of reserve categories acquired. Management utilized the assistance of an independent reserve firm and internal resources to estimate the fair value of the oil and natural gas properties.

The fair value measurements of long-term debt were estimated based on market prices and represent Level 2 inputs. The fair value measurements of derivative instruments assumed were determined based on fair value measurements consistent with managements valuation methodologies including implied market volatility, contract terms and prices and discount factors as of the close date. These inputs represent Level 2 inputs. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk and the derivative instruments in a liability position include a measure of the Company's own nonperformance risk, each based on the current published credit default swap rates.

The fair value of the asset retirement obligations of $5.4 million is included in the oil and natural gas properties with the corresponding liability in the table above. The fair value was based on a discounted cash flow model that included assumptions of current abandonment costs, inflation rates, discount rates and timing of actual abandonment and restoration activities. Due to the inputs and significant assumptions associated with the estimation of asset retirement obligations, the estimates made by management represent Level 3 inputs.

The Covey Park Acquisition qualified as a tax free merger whereby the Company acquired carryover tax basis in Covey Park's assets and liabilities, adjusted for differences between the purchase price allocated to the assets acquired and liabilities assumed based on the fair value and the carryover tax basis.

The Company's results of operations from the closing date on July 16, 2019 through December 31, 2019 include approximately $264.4 million of operating revenues and approximately $93.0 million of operating income, excluding general and administrative and interest expenses, attributable to the Covey Park assets.

Pro forma Results

The pro forma condensed combined financial information for the year ended December 31, 2019 gives effect to the Covey Park Acquisition as if the acquisition had occurred on January 1, 2019. The pro forma condensed combined financial information for year ended December 31, 2018 gives effect to the Covey Park Acquisition and the Jones Contribution as if the transactions had occurred on January 1, 2018. The unaudited pro forma information reflects adjustments for the issuance of the Company's common stock and preferred stock, debt incurred in connection with the transaction, impact of the fair value of properties acquired and related depletion other adjustments the Company believes are reasonable for the pro forma presentation. In addition, the pro forma earnings include acquisition-related costs of $41.0 million for year ended December 31, 2019 and 2018, respectively. The unaudited pro forma results do not reflect any cost savings or other synergies that may arise in the future.

	Pro Forma Year Ended December 31,	
	2018	2019
	(In thousands, except per share amount)	
Revenues:	$1,168,585	$1,147,290
Net Income	$ 180,303	$ 261,406
Net income per share:		
Basic	$ 0.77	$ 1.00
Diluted	$ 0.64	$ 0.82

On November 1, 2019, Comstock acquired a privately held company with producing properties and acreage in the Haynesville shale basin in exchange for 4,500,000 newly issued shares of the Company's common stock. The acquisition qualified as a tax-free reorganization whereby the Company acquired carryover of the sellers inside tax basis and was accounted for as an asset acquisition. Based on the closing price of the Company's common stock of $6.85 per share on November 1, 2019, and the recognition of deferred income taxes associated with the acquisition, the transaction was valued at approximately $42.3 million.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analyses could have a significant impact on the future results of operations.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit ratings. Substantially all of the Company's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which the Company serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. The Company's policy is to assess the collectability of its receivables based upon their age, the credit quality of the purchaser or participant and the potential for revenue offset. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectible. Accordingly, no allowance for doubtful accounts has been provided.

Other Current Assets

Other current assets at December 31, 2018 and 2019 consist of the following:

	As of December 31, 2018	As of December 31, 2019
	(In thousands)	
Advance payments for drilling costs	$ 9,336	$ —
Production tax refunds receivable	1,453	3,661
Pipe and oil field equipment inventory	912	4,503
Other	2,128	2,235
	$ 13,829	$ 10,399

Fair Value Measurements

The Company holds or has held certain financial assets and liabilities that are required to be measured at fair value. These include cash and cash equivalents held in bank accounts and derivative financial instruments in the form of oil and natural gas price swap agreements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. A three-level hierarchy is followed for disclosure to show the extent and level of judgment used to estimate fair value measurements:

Level 1 – Inputs used to measure fair value are unadjusted quoted prices that are available in active markets for the identical assets or liabilities as of the reporting date.

Level 2 – Inputs used to measure fair value, other than quoted prices included in Level 1, are either directly or indirectly observable as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3 – Inputs used to measure fair value are unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions.

The following presents the carrying amounts and the fair values of the Company's financial instruments as of December 31, 2018 and December 31, 2019:

	For the Years Ended December 31,			
	2018		2019	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Assets:				
Commodity-based derivatives[(a)(b)]	$ 15,401	$ 15,401	$ 89,192	$ 89,192
Liabilities:				
Commodity-based derivatives[(a)(b)]	—	—	4,442	4,442
Bank credit facility[(c)]	450,000	450,000	1,250,000	1,250,000
7.5% senior notes due 2025[(d)]	—	—	455,768	534,375
9.75% senior notes due 2026[(d)]	817,066	720,375	820,057	765,000

(a) The Company's oil and natural gas swaps, options, and basis swap agreements and its natural gas price collars are classified as Level 2 and measured at fair value using a market approach using third party pricing services and other active markets or broker quotes that are readily available in the public markets.

(b) As of December 31, 2019, a portion of our natural gas derivatives contain swaptions where the counterparty has the right, but not the obligation, to extend terms of an existing swap on predetermined dates. Due to subjectivity of the inputs used to value the counterparty rights in swaptions, these rights are classified as Level 3 in the fair value hierarchy.

(c) The carrying value of our floating rate debt outstanding approximates fair value because of its floating rate structure.

(d) The fair value of the Company's fixed rate debt was based on quoted prices as of December 31, 2019, a Level 1 measurement.

The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy:

	For the Year Ended December 31, 2019
	(In thousands)
Balance at December 31, 2018	$ —
Total gains:	
Included in earnings	4,351
Settlements, net	—
Transfers out of Level 3	—
Balance at December 31, 2019	$ 4,351

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred to acquire oil and gas leasehold are capitalized. Acquisition costs for proved oil and gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of one barrel of oil for six thousand cubic feet of natural gas. This conversion ratio is not based on the price of oil or natural gas, and there may be a significant difference in price between an equivalent volume of oil versus natural gas. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related facilities disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense. Exploration expense includes geological and geophysical expenses and delay rentals related to exploratory oil and gas properties, costs of unsuccessful exploratory drilling and impairments of unproved properties. As of December 31, 2019, the unproved properties primarily relate to future drilling locations that were not included in proved undeveloped reserves. These future drilling locations are located on acreage where the reservoir is known to be productive but have been excluded from proved reserves due to uncertainty on whether the wells would be drilled within the next five years as required by SEC rules in order to be included in proved reserves. The costs of unproved properties are transferred to proved oil and gas properties when they are either drilled or they are reflected in proved undeveloped reserves and amortized on an equivalent unit-of-production basis. Costs associated with unevaluated exploratory acreage are periodically assessed for impairment on a property by property basis, and any impairment in value is included in exploration expense. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found commercial proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company periodically assesses the need for an impairment of the costs capitalized for its proved oil and gas properties. If impairment is indicated based on undiscounted expected future cash flows attributable to the property, then a provision for impairment is recognized to the extent that net capitalized costs exceed the estimated fair value of the property. The Company determines the fair values of its oil and gas properties using a discounted cash flow model and proved and risk-adjusted probable reserves. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included in the cash flow model include management's outlook for oil and natural gas prices, future oil and natural gas production, production costs, capital expenditures, and the total proved and risk-adjusted probable oil and natural gas reserves expected to be recovered. Management's oil and natural gas price outlook is developed based on third-party longer-term price forecasts as of each measurement date. The expected future net cash flows are discounted using an appropriate discount rate in determining a property's fair value. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of an average price based on the first day of each month of the preceding year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of the oil and gas leases.

In 2017, the Company recognized an impairment of $43.8 million to adjust the carrying value of Comstock's South Texas oil properties which were classified as held for sale at December 31, 2017.

The Company's estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and natural gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be impairments in the carrying values of our oil and gas properties.

Other property and equipment consists primarily of computer equipment, furniture and fixtures and an airplane which are depreciated over estimated useful lives ranging from three to 31½ years on a straight-line basis.

Goodwill

The Company had goodwill of $350.2 million as of December 31, 2018 that was recorded in connection with the Jones Contribution. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets.

During the year ended December 31, 2019, the Company finalized the valuation of the Company's assets and liabilities in connection with the Jones Contribution, which reduced goodwill to $335.9 million as of December 31, 2019.

The Company is not required to amortize goodwill as a charge to earnings; however, the Company is required to conduct an annual review of goodwill for impairment. The Company performs annual assessment of goodwill on October 1st of each year to allow sufficient time to assess goodwill for impairment.

If the carrying value of goodwill exceeds the fair value, an impairment charge would be recorded for the difference between fair value and carrying value.

The Company performed its qualitative assessment of goodwill as of October 1, 2019 and determined there was no indicators of impairment.

Leases

On January 1, 2019, the Company adopted Financial Accounting Standards Board Accounting Standards Codification 842, Leases ("ASC 842"). Comstock adopted this standard using the modified retrospective method of adoption, and it applied ASC 842 only to contracts that were not completed as of January 1, 2019. Upon adoption, there were no adjustments to the opening balance of stockholders' equity.

In adopting ASC 842, the Company utilized certain practical expedients available under ASC 842, including the election to not apply the recognition requirements to short term leases (defined as leases with an initial lease term of twelve months or less which do not contain a purchase option), the election to not separate lease and non-lease components, and the election to not reassess certain land easements in existence prior to January 1, 2019.

Upon adoption of ASC 842, the Company recognized right-of-use lease assets of $5.2 million related to its corporate office lease, certain office equipment and leased vehicles used in oil and gas operations with corresponding short-term and long-term liabilities of $2.0 million and $3.2 million, respectively. The beginning value of the lease assets and liabilities was determined based upon discounted future minimum cash flows contained within each of the respective contracts. The Company utilized a discount rate of 5.0% in computing these discounted net future cash flows. Adoption of ASC 842 did not have a material effect our consolidated statements of operations, cash flows or stockholders' equity.

The Company determines if contracts contain a lease at inception of the contract. To the extent that contract terms representing a lease are identified, leases are identified as being either an operating lease or a finance-type lease. Comstock currently has no finance-type leases. Right-of-use lease assets representing the Company's right to use an underlying asset for the lease term and the related lease liabilities represent our obligation to make lease payments under the terms of the contracts. Short-term leases that have an initial term of one year or less are not capitalized; however, amounts paid for those leases are included as part of its lease cost disclosures. Short-term lease costs exclude expenses related to leases with a lease term of one month or less. Leases applicable to our oil or natural gas operations that include the right to explore for and develop oil and natural gas reserves and the related rights to use the land associated with those leases, are not within the scope of ASC 842.

Comstock contracts for a variety of equipment used in its oil and natural gas exploration and development operations. Contract terms for this equipment vary broadly, including the contract duration, pricing, scope of services included along with the equipment, cancellation terms, and rights of substitution, among others. In applying the accounting guidance within ASC 842, the Company has determined that its corporate office lease, certain office equipment, its vehicles leased for use in operations, and its drilling rigs meet the criteria of an operating lease which require recognition upon adoption of ASC 842.

The Company's drilling operations routinely change due to changes in commodity prices, demand for oil and natural gas, and the overall operating and economic environment. Comstock accordingly manages the terms of its contracts for drilling rigs so as to allow for maximum flexibility in responding to these changing conditions. The Company's rig contracts are presently either for periods of less than one year, or they are on terms that provide for cancellation with thirty days advance notice without a specified expiration date. The Company has elected to apply the practical expedient available under ASC 842 for short-term leases and not recognize right-of-use lease assets for these rig contracts. The costs associated with drilling rig operations are accounted for under the successful efforts method, which generally require that these costs be capitalized as part of our proved oil and natural gas properties on our balance sheet unless they are incurred on exploration wells that are unsuccessful, in which case they are charged to exploration expense.

Lease costs recognized during the twelve months ended December 31, 2019 were as follows:

	For the Year Ended December 31, 2019
	(In thousands)
Operating lease cost included in general and administrative expense	$ 1,646
Operating lease cost included in lease operating expense	396
Short-term lease cost (drilling rig costs included in proved oil and gas properties)	20,527
	$22,569

Cash payments for operating leases associated with right-of-use assets included in cash provided by operating activities were $2.0 million for the twelve months ended December 31, 2019.

As of December 31, 2019, the operating leases have a weighted average remaining term of 1.96 years. Comstock had the following liabilities under contracts that contain operating leases:

	(In thousands)
2020	$1,994
2021	1,689
Total lease payments	3,683
Imputed interest	(174)
Total lease liability	$3,509

Accrued Expenses

Accrued expenses at December 31, 2018 and 2019 consist of the following:

	As of December 31, 2018	As of December 31, 2019
	(In thousands)	
Accrued interest payable	$ 35,461	$ 39,501
Accrued drilling costs	17,920	42,193
Accrued transportation costs	4,632	26,907
Accrued transaction costs	—	10,830
Accrued employee compensation	6,045	8,653
Accrued lease operating expenses	2,130	4,990
Other	1,898	4,092
	$ 68,086	$137,166

Reserve for Future Abandonment Costs

The Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal. The Company records a liability in the period in which an asset retirement obligation is incurred, in an amount equal to the estimated fair value of the obligation that is capitalized. Thereafter, this liability is accreted up to the final retirement cost. Accretion of the discount is included as part of depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The following table summarizes the changes in the Company's total estimated liability:

	Predecessor	Successor	
	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
		(In thousands)	
Reserve for future abandonment costs at beginning of the year	$10,407	$4,683	$ 5,136
Wells acquired	—	—	5,700
New wells placed on production	17	50	516
Changes in estimates and timing	—	270	6,333
Liabilities settled	(87)	—	(57)
Asset divestitures	—	—	(45)
Accretion expense	346	133	568
Reserve for future abandonment costs at end of the year	$10,683	$5,136	$18,151

Stock-based Compensation

The Company has stock-based employee compensation plans under which stock awards, comprised primarily of restricted stock and performance share units, are issued to employees and non-employee directors. The Company follows the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Segment Reporting

The Company presently operates in one business segment, the exploration and production of oil and natural gas.

Derivative Financial Instruments and Hedging Activities

The Company accounts for derivative financial instruments (including derivative instruments embedded in other contracts) as either an asset or liability measured at its fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities.

Major Purchasers

In 2017, the Company had four major purchasers of its oil and natural gas production that accounted for 34%, 17%, 16% and 15% of its total oil and gas sales. In the Predecessor Period January 1, 2018 through August 13, 2018 the Company had three major purchasers of its oil and gas production that accounted for 33%, 22% and 20% of its total oil and natural gas sales. During the Successor Period August 14, 2018 through December 31, 2018, the Company had two major purchasers of its oil and natural gas production that accounted for 32% and 18% of its total oil and natural gas sales. In 2019, the

Company had three major purchasers of its oil and natural gas production that accounted for 19%, 16% and 12% of its total oil and gas sales. The loss of any of these purchasers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Revenue Recognition and Gas Balancing

On January 1, 2018, the Company adopted Financial Accounting Standards Board ("FASB") Accounting Standards Update ("ASU") 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"). Comstock adopted this standard using the modified retrospective method of adoption, and it applied the ASU only to contracts that were not completed as of January 1, 2018. Upon adoption, there were no adjustments to the opening balance of equity.

Comstock produces oil and natural gas and reports revenues separately for each of these two primary products in its statements of operations. Revenues are recognized upon the transfer of produced volumes to the Company's customers, who take control of the volumes and receive all the benefits of ownership upon delivery at designated sales points. Payment is reasonably assured upon delivery of production. All sales are subject to contracts that have commercial substance, contain specific pricing terms, and define the enforceable rights and obligations of both parties. These contracts typically provide for cash settlement within 25 days following each production month and are cancellable upon 30 days' notice by either party. Prices for sales of oil and natural gas are generally based upon terms that are common in the oil and gas industry, including index or spot prices, location and quality differentials, as well as market supply and demand conditions. As a result, prices for oil and natural gas routinely fluctuate based on changes in these factors. Each unit of production (barrel of crude oil and thousand cubic feet of natural gas) represents a separate performance obligation under the Company's contracts since each unit has economic benefit on its own and each is priced separately according to the terms of the contracts.

Comstock has elected to exclude all taxes from the measurement of transaction prices, and its revenues are reported net of royalties and exclude revenue interests owned by others because the Company acts as an agent when selling crude oil and natural gas, on behalf of royalty owners and working interest owners. Revenue is recorded in the month of production based on an estimate of the Company's share of volumes produced and prices realized. The Company recognizes any differences between estimates and actual amounts received in the month when payment is received. Historically, differences between estimated revenues and actual revenue received have not been significant. The amount of oil or natural gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. The Company did not have any significant imbalance positions at December 31, 2018 or 2019. Sales of oil and natural gas generally occur at or near the wellhead. When sales of oil and gas occur at locations other than the wellhead, the Company accounts for costs incurred to transport the production to the delivery point as gathering and transportation expenses. The Company has recognized accounts receivable of $120.1 million as of December 31, 2019 from customers for contracts where performance obligations have been satisfied and an unconditional right to consideration exists.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are received from working interest owners of the oil and gas properties operated by the Company of $11.7 million, $8.5 million, $4.5 million and $16.8 million in 2017, for the Predecessor Period from January 1, 2018 through August 13, 2018, for the Successor Period from August 14, 2018 through December 31, 2018 and 2019, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the tax consequences attributable to the future utilization of existing net operating loss and other carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

Earnings Per Share

Unvested share-based payment awards containing nonforfeitable rights to dividends are considered to be participating securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Performance share units ("PSUs") represent the right to receive a number of shares of the Company's common stock that may range from zero to up to two times the number of PSUs granted on the award date based on the achievement of certain performance measures during a performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective period, assuming that date was the end of the contingency period. The treasury stock method is used to measure the dilutive effect of PSUs. Unexercised common stock warrants represent the right to convert the warrants into common stock at an exercise price of $0.01 per share. The treasury stock method is used to measure the dilutive effect of unexercised common stock warrants. The shares that would be issuable upon exercise of the conversion right contained in the Company's convertible debt each period were based on the if-converted method for computing potentially dilutive shares of common stock that could be issued upon conversion. None of the Company's participating securities participate in losses and as such are excluded from the computation of basic earnings per share during periods of net losses. The Series A and Series B Convertible Preferred Stock issued in connection with the Covey Park Acquisition will become convertible into in the aggregate 96,250,000 shares of common stock beginning on July 16, 2020. The dilutive effect of preferred stock is computed using the if-converted method as if conversion of the preferred shares had occurred at the earlier of the date of issuance or the beginning of the period. For the twelve months ended December 31, 2019, the preferred stock was dilutive.

Basic and diluted earnings per share were determined as follows:

	Successor					
	For the Period from August 14, 2018 through December 31, 2018			Twelve Months Ended December 31, 2019		
	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except per share amounts)					
Net income attributable to common stock	$64,122			$74,474		
Income allocable to unvested restricted shares	(248)			(356)		
Basic and diluted net income attributable to common stock	63,874	105,453	$0.61	74,118	142,750	$0.52
Effect of Dilutive Securities:						
Performance stock units	—	—		—	63	
Preferred stock	—	—		22,415	44,565	
Stock warrants	—	6		—	—	
Diluted income attributable to common stock	$63,874	105,459	$0.61	$96,533	187,378	$0.52

	Predecessor					
	Twelve Months Ended December 31, 2017			For the Period January 1, 2018 through August 13, 2018		
	Loss	Shares	Per Share	Loss	Shares	Per Share
	(In thousands, except per share amounts)					
Basic and diluted net loss attributable to common stock	$(111,405)	14,644	$(7.61)	$(92,754)	15,262	$(6.08)

Basic and diluted per share amounts are the same for the Predecessor Periods due to the net loss in those periods.

Shares of unvested restricted stock are included in common stock outstanding as such shares have a nonforfeitable right to participate in any dividends that might be declared and have the right to vote. Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
Unvested restricted stock *(in thousands)*	612	839	410	685

All stock options, unvested PSUs, warrants exercisable into common stock and contingently issuable shares related to the convertible debt that were anti-dilutive to earnings and excluded from weighted average shares used in the computation of earnings per share were as follows:

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Weighted average PSUs	274	476	328	776
Weighted average grant date fair value per unit	$ 17.12	$ 13.83	$12.93	$9.56
Weighted average warrants for common stock	463	142	—	—
Weighted average exercise price per share	$ 0.01	$ 0.01	—	—
Weighted average contingently convertible shares	37,046	39,819	—	—
Weighted average conversion price per share	$ 12.32	$ 12.32	—	—

Supplementary Information With Respect to the Consolidated Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Cash payments made for interest and income taxes were as follows:

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Cash payments for:				
Interest payments	$73,941	$36,187	$ 8,042	$149,039
Income tax payments	$ 3	$ 2	$ —	2
Non-cash investing activities include:				
Increase (decrease) in accrued capital expenditures	$ (1,624)	$ (3,255)	$ 15,301	$ 24,273
Non-cash investing and financing activities related to acquisitions				
Issuance of common stock	$ —	$ —	$760,829	$198,633
Issuance of Series A Convertible Preferred Stock	$ —	$ —	$ —	$200,000
Assumed 7 1/2% senior notes	$ —	$ —	$ —	$446,625
Acquired working capital	$ —	$ —	$ 36,351	$ 41,365

The Company paid $38.1 million and $25.0 million of interest in-kind on its convertible notes in 2017 and the Predecessor Period from January 1, 2018 through August 13, 2018, respectively.

Recent accounting pronouncements

In January 2017, the FASB issued Accounting Standards Update No. 2017-04 (ASU 2017-04) "Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment." ASU 2017-04 eliminates step two of the goodwill impairment test and specifies that goodwill impairment should be measured by comparing the fair value of a reporting unit with its carrying amount. ASU 2017-04 is effective for annual or interim goodwill impairment tests performed in fiscal years beginning after December 15, 2019 and early adoption is permitted. We did not early adopt ASU 2017-04 and will implement ASU 2017-04 on our financial statements when we perform annual impairment assessments following adoption of this standard in 2020. We do not expect the update to have a significant effect on our results of operations, liquidity or financial position.

In February 2016, the FASB issued ASU No. 2016-02, Leases ("ASU 2016-02"). ASU 2016-02 requires lessees to include most leases on their balance sheets, but recognize lease costs in their financial statements in a manner similar to accounting for leases prior to ASC 2016-02. ASU 2016-02 is effective for annual periods ending after December 15, 2018 and interim periods thereafter. We adopted ASC 2016-02 beginning January 1, 2019. We used the modified retrospective method of adoption for this new standard and are utilizing certain practical expedients as part of our adoption. The adoption of ASU 2016-02 did not have a significant effect on our results of operations, liquidity or financial position.

In June 2016, The FASB issued Accounting Standards Update ASU No. 2016-13 ("ASU 2016-13") that amends guidance on reporting credit losses for trade receivables, net investments in leases, debt securities, loans and certain other instruments. ASU 2016-13 requires the use of a forward-looking expected loss model as opposed to existing incurred loss recognition. The update is effective for us beginning in 2020. The guidance requires a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the standard is effective. We are continuing to evaluate the provisions of this update, but we currently do not expect it will have a material impact on our results of operations, financial position and financial disclosures.

(2) Acquisitions and Dispositions of Oil and Gas Properties

In October 2017, the Company adopted a plan of sale for its Eagle Ford shale oil properties located in South Texas and recognized an impairment of $43.8 million in the fourth quarter of 2017 to adjust the carrying value of these assets to their fair value less costs to sell. The Company determined the fair value based on estimated discounted future net cash flows of the properties appropriately risk adjusted based on indication of values received from potential acquirers in a competitive bid process. The asset retirement liability of $4.6 million associated with these assets was reclassified to current liabilities as of December 31, 2017. In April 2018, Comstock completed the sale of its producing Eagle Ford shale oil and gas properties for $106.4 million and retained the undeveloped acreage. The Company recognized a loss on sale of these properties of $32.7 million during the Predecessor Period from January 1, 2018 through August 13, 2018.

Results of operations for the properties that were sold during the Predecessor Period from January 1 through August 13, 2018 were as follows:

	Predecessor
	For the Period from January 1, 2018 through August 13, 2018
	(In thousands)
Total oil and gas sales	$17,747
Total operating expenses[(a)]	(6,134)
Operating income	$11,613

(a) Includes direct operating expenses, depreciation, depletion and amortization and exploration expense. Excludes interest expense, general and administrative expenses and depreciation, depletion and amortization expense subsequent to the date the assets were designated as held for sale.

In 2017, the Company entered agreements to jointly develop certain acreage prospective for the Haynesville shale in Louisiana and Texas with USG Properties Haynesville, LLC ("USG"). As of December 31, 2017, USG had acquired approximately 6,300 net acres prospective for Haynesville shale development for the joint development program primarily in Caddo Parish, Louisiana. The Company operates wells drilled on USG's acreage and has the right to acquire a 25% working interest in the first twelve wells drilled on the acreage and 40% for all subsequent wells by reimbursing USG for the attributable acreage costs of the wells being drilled. USG is also participating in a Haynesville shale drilling program on approximately 5,700 acres of Comstock's acreage in Harrison County, Texas. Under the terms of the participation agreements, Comstock receives $1.1 million for 50% of Comstock's interest for each location for acreage and infrastructure related to each well location, with $400,000 of that amount being paid only if each well meets or exceeds established production targets. Comstock also receives $80,000 for each well drilled as consideration for the Company's services managing the joint development program in addition to customary operating fees for each well drilled.

On July 31, 2018, the Company acquired oil and gas properties in North Louisiana and Texas for $41.5 million. These properties included 22,559 acres (12,085 net) and 114 (27.8 net) producing natural gas wells, 47 (14.6 net) of which produce from the Haynesville shale.

On August 14, 2018, as part of the Jones Contribution, the strategic drilling venture previously entered into by the Company and Arkoma Drilling, LP was terminated and Comstock re-acquired working interests in wells drilled under the joint venture for $17.9 million representing the costs paid by Arkoma Drilling, LP.

On September 21, 2018, the Company entered into a joint development venture with an affiliate of USG by contributing its undeveloped Eagle Ford shale acreage. Under the joint development venture, Comstock can participate in drilling wells on the undeveloped acreage and can participate in any in-fill wells or refracs of existing wells on acreage owned by the joint venture partner. Comstock subsequently sold a portion of the undeveloped acreage in the joint venture for proceeds of $13.7 million in September 2018.

On December 19, 2018, the Company entered into an agreement to acquire an 88% interest in the Haynesville shale rights covering 6,149 gross acres (5,301 net) in Harrison and Panola counties, Texas.

The Company will pay $20.5 million over a four year period by providing a 12% interest in each well drilled by Comstock on the acreage. Comstock has identified 33 (22.7 net) potential drilling locations on this acreage.

On July 16, 2019, the Company acquired Covey Park Energy LLC, for consideration valued at approximately $2.2 billion. The acquisition included 317,142 acres (248,196 net) with 1,230 (712.0 net) producing natural gas wells, 844 (383.0 net) of which produce from the Haynesville/Bossier shales.

On November 1, 2019, the Company acquired a privately held company in exchange for 4.5 million newly issued shares of the Company's common stock. The properties acquired included 7,702 acres (3,155 net) and 75 (20.1 net) producing natural gas wells, 36 (11.7 net) of which produce from the Haynesville shale.

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and natural gas property acquisition, development and exploration activities:

Capitalized Costs

	Successor	
	As of December 31, 2018	As of December 31, 2019
	(In thousands)	
Proved properties:		
Leasehold costs	$1,010,987	$2,912,196
Wells and related equipment and facilities	671,177	1,165,317
Accumulated depreciation depletion and amortization	(210,452)	(485,851)
	1,471,712	3,591,662
Unproved properties	191,929	410,897
	$1,663,641	$4,002,559

Costs Incurred

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Property acquisitions	$ —	$ 39,323	$ 21,013	$ 2,097,451
Exploration and development:				
Development leasehold	4,698	2,848	1,715	7,603
Development drilling	164,472	90,840	148,745	493,625
Other development	9,644	13,871	13,612	9,339
Total capital expenditures	$ 178,814	$ 107,559	$ 164,072	$ 510,567

(4) Long-term Debt

Long-term debt is comprised of the following:

	Successor	
	As of December 31, 2018	As of December 31, 2019
	(In thousands)	
7 ½% Senior Notes due 2025:		
Principal	—	625,000
Discount, net of amortization	—	(169,232)
9 ¾% Senior Notes due 2026:		
Principal	850,000	850,000
Discount, net of amortization	(32,934)	(29,943)
Bank Credit Facility:		
Principal	450,000	1,250,000
Debt issuance costs, net of amortization	(22,703)	(25,693)
	$ 1,244,363	$ 2,500,132

The discounts on the senior notes are being amortized over the lives of the senior notes using the effective interest rate method. Issuance costs are amortized over the lives of the senior notes on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

The following table summarizes Comstock's principal amount of debt as of December 31, 2019 by year of maturity:

	2020	2021	2022	2023	2024	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ —	$ —	$1,250,000	$ —	$1,250,000
7½% Senior Notes Due 2025	—	—	—	—	—	625,000	625,000
9¾% Senior Notes Due 2026	—	—	—	—	—	850,000	850,000
	$ —	$ —	$ —	$ —	$1,250,000	$1,475,000	$2,725,000

In connection with the Jones Contribution, the Company completed a series of refinancing transactions to retire all of its then-outstanding senior secured and unsecured notes. On August 3, 2018, the Company issued $850.0 million of new senior notes for proceeds of $815.9 million. Interest on the notes is payable on February 15 and August 15 at an annual rate of 9¾% and the notes mature on August 15, 2026. As a part of the Covey Park Acquisition, the Company assumed $625.0 million of senior notes. The fair market value of the notes at the closing was $446.6 million. Interest on the assumed notes is payable on May 15 and November 15 at an annual rate of 7½%. The notes mature on May 15, 2025.

On August 14, 2018, the Company entered into a bank credit facility with Bank of Montreal, as administrative agent, and the participating banks. The bank credit facility was subject to a borrowing base of $700.0 million which was re-determined on a semi-annual basis and upon the occurrence of certain other events. Concurrent with the closing of the Covey Park Acquisition, the bank credit facility was amended and restated to provide for a $1,575.0 million borrowing base which will be re-determined on a semi-annual basis and upon the occurrence of certain other events. The maturity date was extended to July 16, 2024. The initial committed borrowing base was set at $1,500.0 million, of which $1,250.0 million of borrowings were outstanding as of December 31, 2019. The borrowing base was reaffirmed in November 2019 during its scheduled redetermination. Borrowings under the bank credit facility are secured by substantially all of the assets of the Company and its subsidiaries and bears interest at the Company's option, at either LIBOR plus 1.75% to 2.75% or a base rate plus 0.75% to 1.75%, in each case depending on the utilization of the borrowing base. The Company also pays a commitment fee of 0.375% to 0.5% on the unused borrowing base. The bank credit facility places certain restrictions upon the Company's and its restricted subsidiaries' ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the senior notes. The only financial covenants are the maintenance of a leverage ratio of less than 4.0 to 1.0 and an adjusted current ratio of at least 1.0 to 1.0. The financial covenants are determined starting with the financial results for the three months ended December 31, 2019. The Company was in compliance with the covenants as of December 31, 2019.

(5) Commitments and Contingencies

The Company rents office space and other facilities under noncancelable operating leases. Rent expense for the year ended December 31, 2017 was $1.6 million. Rent for the Predecessor Period of January 1, 2018 to August 13, 2018 and the Successor Period of August 14, 2018 to December 31, 2018 was $1.0 million and $0.6 million, respectively. Rent for the year ended December 31, 2019 was $1.7 million. Minimum future lease payments as of December 31, 2019 are $2.9 million for 2020, $2.2 million for 2021 and $0.5 million for 2022.

The Company has entered into natural gas transportation contracts which expire beginning October 2021 and extend through October 2031. Commitments under these contracts are $10.7 million for 2020, $12.0 million for 2021, $24.9 million per year for 2022 through 2024 and $169.6 million for the remaining term of the contracts.

The Company has drilling rig contracts and completion service contracts. Terms of drilling contracts vary from well to well, or are for periods of less than one year. The service contracts are generally cancellable with 30 to 60 days' notice. Existing commitments under these contracts is $36.4 million as of December 31, 2019.

From time to time, the Company is involved in certain litigation that arise in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company does not believe the resolution of these matters will have a material effect on the Company's financial position, results of operations or cash flows and no material amounts are accrued relative to these matters at December 31, 2018 or 2019.

(6) Preferred Stock

In connection with the Covey Park Acquisition, the Company issued 210,000 shares of Series A Convertible Preferred Stock with a redemption value of $210.0 million and a fair value of $200.0 million as part of the consideration for the acquisition and sold 175,000 shares of Series B Convertible Preferred Stock for $175.0 million to its majority stockholder. Holders of the newly issued convertible preferred stock are entitled to receive quarterly dividends at a rate of 10% per annum, which are paid in arrears. At any time after July 16, 2020, each holder may convert any or all shares of preferred stock into shares of the Company's common stock at a conversion price of $4.00 per share, or an aggregate of 96,250,000 shares of the Company's common stock, subject to adjustment pursuant to customary anti-dilution provisions. The Company has the right to redeem the preferred stock at any time at face value plus accrued dividends. The Series A Convertible Preferred Stock and Series B Convertible Preferred Stock are classified as mezzanine equity based on the majority stockholder's ability to control the terms of conversion to common stock. The difference in the fair value of the Series A Convertible Preferred Stock and the redemption value is being accreted to the redemption value of $210.0 million over a one year period to reflect the value of the preferred stock on July 16, 2020, when the preferred shares become convertible.

(7) Stockholders' Equity

On July 16, 2019, the Company amended its Second Amended and Restated Articles of Incorporation to increase its authorized capital to 405,000,000 shares, of which 400,000,000 shares are common stock, $0.50 par value per share, and 5,000,000 are preferred stock, $10.00 par value per share.

In 2017, holders of the Company's convertible notes converted $9.9 million of principal amount of the notes into 826,327 shares of common stock, respectively.

During 2017 and 2018, warrants were exercised for 1,502,255 and 402,708 shares of common stock, respectively, and 11,955 warrants expired without being exercised on September 7, 2018. All warrants for common stock were either exercised or expired unused in 2018.

(8) Stock-based Compensation

The Company grants restricted shares of common stock and performance share units ("PSUs") to key employees and directors as part of their compensation. Grants are made pursuant to the 2019 Long-term Incentive Plan (the "2019 Plan"), which was approved by the Company's shareholders on May 31, 2019 at the Company's Annual Meeting. Upon approval of the 2019 Plan, the 2009 Long-term Incentive Plan (the "2009 Plan") was amended, restated and merged with and into the 2019 Plan. Future awards of performance share units, restricted stock grants or other equity awards available under the 2019 Long-term Incentive Plan as of December 31, 2019 were 5,501,598 shares of common stock.

Stock-based compensation expense is included in general and administrative expenses. During 2017, and for the Predecessor Period from January 1, 2018 through August 13, 2018 the Company had $5.9 million and $3.9 million, respectively, in stock-based compensation expense. For the Successor Period from August 14, 2018 through December 31, 2018, and during 2019 the Company had $1.0 million and $4.0 million, respectively, in stock-based compensation expense.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period, generally one to three years, using the straight-line method. The fair value of each restricted share on the date of grant is equal to the market price of a share of the Company's stock.

A summary of restricted stock activity is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2019	414,545	$8.70
Granted	874,661	$5.40
Vested	(163,641)	$8.53
Forfeitures	(33,256)	$7.74
Outstanding at December 31, 2019	1,092,309	$6.11

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands, except per share data)			
Fair value of vested restricted stock	$1,684	$2,676	$3,541	$ 925
Per share weighted average fair value	$11.11	$ 8.51	$ 8.70	$ 5.40
Compensation expense recognized for restricted stock grants	$3,891	$2,262	$ 451	$ 2,121
Unrecognized compensation expense related to unvested shares				$ 5,500
Expected recognition period				2.2 years

Performance Share Units

The Company issues PSUs as part of its long-term equity incentive compensation. PSU awards can result in the issuance of common stock to the holder if certain performance criteria are met during a performance period. The performance periods consist of three years. The performance criteria for the PSUs are based on the Company's annualized total stockholder return ("TSR") for the performance period as compared with the TSR of certain peer companies for the performance period. The costs associated with PSUs are recognized as general and administrative expense over the performance periods of the awards.

The fair value of PSUs was measured at the grant date using the Geometric Brownian Motion Model ("GBM Model"). Significant assumptions used in this simulation include the Company's expected volatility and a risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods, as well as the volatilities for each of the Company's peers. Assumptions regarding volatility included the historical volatility of each company's stock and the implied volatilities of publicly traded stock options.

Significant assumptions used to value PSUs included:

	Predecessor		Successor	
	Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
Risk free interest rate	1.6%	2.3%	2.7%	1.5%
Range of implied volatility:				
Minimum	37%	42%	30%	32%
Maximum	134%	146%	88%	84%

The fair value of PSUs is amortized over the vesting period of three years, using the straight-line method. The final number of shares of common stock issued may vary depending upon the performance multiplier, and can result in the issuance of zero to 1,863,780 shares of common stock based on the achieved performance ranges from zero to two.

A summary of PSU activity is presented below:

	Number of PSUs	Weighted Average Grant Price
Outstanding at January 1, 2019	335,545	$12.93
Granted	618,672	$ 7.85
Forfeitures	(22,327)	$12.93
Outstanding at December 31, 2019	931,890	$ 9.56

	Predecessor		Successor	
	2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	2019
	(In thousands, except per unit data)			
Number of PSUs granted	242	361	336	619
Grant date fair value	$4,395	$4,517	$4,339	$ 4,857
Grant date fair value per unit	$18.17	$12.52	$12.93	$ 7.85
Compensation expense recognized for PSUs	$2,032	$1,651	$ 543	$ 1,899
Unrecognized compensation expense related to unvested shares				$ 6,464
Expected recognition period				2.3 years

During the Predecessor Period from January 1, 2018 through August 13, 2018, 85,987 PSUs were earned and converted into restricted stock. The change of control that occurred due to the Jones Contribution resulted in the vesting of all then outstanding performance share units at the maximum amount that could be earned, and a total of 1,028,672 shares of common stock were issued related to the earned PSUs with a fair value of $8.8 million.

(9) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match the employees' contributions to the plan. Matching contributions to the plan were $761,000, $508,000, $252,000 and $1,041,000 for the years ended December 31, 2017, the Predecessor Period from January 1, 2018 through August 13, 2018, the Successor Period from August 14, 2018 through December 31, 2018, and 2019, respectively.

(10) Income Taxes

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. The following is an analysis of the consolidated income tax provision (benefit):

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Current - Federal	$ (19,086)	$ —	$ (1,349)	$ —
Current - State	136	13	82	(223)
Deferred - Federal	—	2,412	16,406	27,550
Deferred - State	1,006	(1,360)	3,805	476
	$ (17,944)	$ 1,065	$ 18,944	$ 27,803

In recording deferred income tax assets, the Company considers whether it is more likely than not that its deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that all of its deferred tax assets will be realized. As a result, the Company established valuation allowances for its deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. The Company will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future periods.

The Tax Cuts and Jobs Act, which was enacted on December 22, 2017, reduced the corporate income tax rate effective January 1, 2018 from 35% to 21%. Among the other significant tax law changes that potentially affect the Company are the elimination of the corporate alternative minimum tax ("AMT"), changes that require operating losses incurred in 2018 and beyond be carried forward indefinitely with no carryback up to 80% of taxable income in a given year, and limitations on the deduction for interest expense incurred in 2018 or later of up to 30% of its adjusted taxable income (defined as taxable income before interest and net operating losses) for the taxable year. For the tax years beginning before January 1, 2022, the adjusted taxable income for these purposes is also adjusted to exclude the impact of depreciation, depletion and amortization. The Tax Cuts and Jobs Act preserved deductibility of intangible drilling costs for federal income tax purposes, which allows the Company to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable in periods of taxable income. In December 31, 2018, the Company completed its accounting for the tax effects of enactment of the Tax Cuts and Jobs Act. The Company remeasured certain deferred federal tax assets and liabilities based on the rates at which they are expected to reverse in the future, which is generally 21%. The amount recognized related to the remeasurement of its deferred federal tax balance was $140.4 million, which was subject to a valuation allowance. The Tax Cuts and Jobs Act repealed the AMT for tax years beginning on or after January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset federal taxes for any taxable year. In addition, 50% of any unused AMT credit carryforwards can be refunded during tax years 2018 through 2020. The Company had $20.4 million of unused AMT credit carryforwards as of December 31, 2018, of which $10.2 million was refunded during 2019.

The difference between the customary rate of 35% for 2017, 21% for 2018 and 2019 and the effective tax rate on income (losses) is due to the following:

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Tax at statutory rate	$ (45,272)	$ (19,255)	$ 17,444	$ 26,185
Tax effect of:				
AMT credit refundable	(19,086)	—	(1,349)	—
Valuation allowance on deferred tax assets	41,116	22,053	(903)	(494)
State income taxes, net of federal benefit	(892)	(3,599)	3,863	(499)
Nondeductible transaction costs	—	—	—	1,417
Nondeductible stock-based compensation	1,408	668	(120)	886
Net operating loss expirations	1,548	—	—	—
Other	3,234	1,198	9	308
Total	$ (17,944)	$ 1,065	$ 18,944	$ 27,803

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
Tax at statutory rate	35.0%	21.0%	21.0%	21.0%
Tax effect of:				
AMT credit refundable	14.8	—	(1.6)	—
Valuation allowance on deferred tax assets	(31.8)	(24.1)	(1.1)	(0.4)
State income taxes, net of federal benefit	0.7	3.9	4.7	(0.4)
Nondeductible transaction costs	—	—	—	1.1
Nondeductible stock-based compensation	(1.1)	(0.7)	(0.1)	0.7
Net operating loss expirations	(1.2)	—	—	—
Other	(2.5)	(1.3)	—	0.3
Effective tax rate	13.9%	(1.2)%	22.9%	22.3%

The tax effects of significant temporary differences representing the net deferred tax liability at December 31, 2018 and 2019 were as follows:

	Successor	
	2018	2019
	(In thousands)	
Deferred tax assets:		
Asset retirement obligation	$ 2,329	$ 3,812
Net operating loss carryforwards	65,317	51,656
Interest expense limitation	45,265	62,552
Gain on debt exchange and original issue discount	42	2,127
Other	3,711	6,895
	116,664	127,042
Valuation allowance on deferred tax assets	(18,390)	(16,876)
Deferred tax assets	98,274	110,166
Deferred tax liabilities:		
Property and equipment	(252,668)	(269,587)
Unrealized hedging income	(3,399)	(10,763)
Amortization of bond discount	—	(37,458)
Other	(4,124)	(4,130)
Deferred tax liabilities	(260,191)	(321,938)
Net deferred tax liability	$(161,917)	$(211,772)

At December 31, 2019, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amount
		(In thousands)
Net operating loss – U.S. federal	2019 - 2037	$ 906,317
Net operating loss – U.S. federal	Unlimited	$ 3,813
Net operating loss – state taxes	2020 - 2037	$1,538,152
Interest expense – U.S. Federal	Unlimited	$ 297,875

The shares of common stock issued as a result of the Jones Contribution triggered an ownership change under Section 382 of the Internal Revenue Code. As a result, the Company's ability to use net operating losses ("NOLs") generated before the change in control to reduce taxable income is generally limited to an annual amount based on the fair market value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. The Company's NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of the Company's common stock immediately prior to the ownership change, Comstock believes that it has a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carry forwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire. NOLs generated in 2018 and after would be carried forward indefinitely. Comstock's use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If the Company does not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then it will lose the ability to apply those NOLs as offsets to future taxable income. The Company estimates that $840.4 million of the U.S. federal NOL carryforwards and $1.4 billion of the estimated state NOL carryforwards will expire unused.

The Company's federal income tax returns for the years subsequent to December 31, 2014 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2016. The Company currently believes that its significant filing positions are highly certain and that all of its other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions.

(11) Derivative Financial Instruments and Hedging Activities

Comstock uses commodity swaps, basis swaps, collars and swaptions to hedge oil and natural gas prices to manage price risk. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume or amounts hedged. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and cap. Swaptions are a combined derivative which includes a fixed price swap and a sold option to extend the volume hedged.

All of the Company's derivative financial instruments are used for risk management purposes and, by policy, none are held for trading or speculative purposes. Comstock minimizes credit risk to counterparties of its derivative financial instruments through formal credit policies, monitoring procedures, and diversification. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the assets securing its bank credit facility. None of the Company's derivative financial instruments involve payment or receipt of premiums. The Company classifies the fair value amounts of derivative financial instruments as net current or noncurrent assets or liabilities, whichever the case may be, by commodity contract.

All of Comstock's natural gas derivative financial instruments are tied to the Henry Hub-NYMEX price index and all of its oil derivative financial instruments are tied to the WTI-NYMEX index price.

Basis swaps are tied to Henry Hub. The Company had the following outstanding commodity-based derivative financial instruments, excluding basis swaps which are discussed separately below, at December 31, 2019:

	Future Production Period			
	Year Ending December 31, 2020	Year Ending December 31, 2021	Year Ending December 31, 2022	Total
Natural Gas Swap Contracts:				
Volume (MMBtu)	106,464,209	20,908,140	10,950,000	138,322,349
Average Price per MMBtu	$ 2.79	$ 2.87	$ 2.81	$ 2.81
Natural Gas 2-Way Collar Contracts:				
Volume (MMBtu)	16,350,000	—	—	16,350,000
Price per MMBtu:				
Average Ceiling	$ 3.46	—	—	$ 3.46
Average Floor	$ 2.47	—	—	$ 2.47
Natural Gas 3-Way Collar Contracts:				
Volume (MMBtu)	26,510,000	—	—	26,510,000
Price per MMBtu:				
Average Ceiling	$ 2.99	—	—	$ 2.99
Average Floor	$ 2.65	—	—	$ 2.65
Average Put	$ 2.33	—	—	$ 2.33
Natural Gas Swaptions Contracts:				
Volume (MMBtu)	54,010,000[(a)]	11,800,000[(b)]	—	65,810,000
Average Price per MMBtu	$ 2.52	$ 2.53	—	$ 2.52
Crude Oil Collar Contracts:				
Volume (Barrels)	1,262,600	—	—	1,262,600
Price per Barrel:				
Average Ceiling	$ 64.92	—	—	$ 64.92
Average Floor	$ 48.65	—	—	$ 48.65

(a) The counterparty has the right to extend hedged volumes of 53,900,000 MMBtu of swaptions placed in 2020 into 2021 at an average price of $2.52 per MMBtu.
(b) The counterparty has the right to extend hedged volumes of 22,750,000 MMBtu of swaptions placed in 2020 and 2021 into 2022 at an average price $2.52 per MMBtu.

In addition to the swaps, collars and swaptions above, the Company had basis swap contracts that lock-in differentials between NYMEX Henry Hub and certain physical pricing indices. These contracts settle monthly through December 2022 and include volumes of 47,510,000 MMBtu. The fair value of these contracts was a net asset of $2.0 million at December 31, 2019.

Subsequent to December 31, 2019, the Company has added 28,000,000 MMBtu of additional natural gas swaptions agreements at an average price of $2.51 per MMBtu, with an additional 43,800,000 subject to option exercises, at an average price of $2.51 per MMBtu. These contracts begin in January 2020, April 2020 or January 2021 with one year terms after which extensions could be executed for additional one year terms. None of the derivative contracts were designated as cash flow hedges. The Company recognizes cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses).

None of the Company's derivative contracts were designated as cash flow hedges. The aggregate fair value of the Company's derivative instruments reported in the accompanying consolidated balance sheets by type, including the classification between assets and liabilities, consists of the following:

Type	Consolidated Balance Sheet Location	Fair Value
		(in thousands)
Fair Value of Derivative Instruments as of December 31, 2018		
Asset Derivatives:		
Natural gas price derivatives	Derivative Financial Instruments – current	$ 6,096
Oil price derivatives	Derivative Financial Instruments – current	9,305
		$15,401
Fair Value of Derivative Instruments as of December 31, 2019		
Asset Derivatives:		
Natural gas price derivatives	Derivative Financial Instruments – current	$75,123
Oil price derivatives	Derivative Financial Instruments – current	181
		$75,304
Natural gas price derivatives	Derivative Financial Instruments – long-term	$13,888
Liability Derivatives:		
Oil price derivatives	Derivative Financial Instruments – current	$ 222
Natural gas price derivatives	Derivative Financial Instruments – long-term	$ 4,220

The Company recognized cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses). Gains and losses related to the change in the fair value of the Company's derivative contracts recognized in the consolidated statement of operations were as follows:

Gain/(Loss) Recognized in Earnings on Derivatives	Predecessor		Successor	
	For the Year Ended December 31, 2017	For the Period from January 1, 2018 through August 13, 2018	For the Period from August 14, 2018 through December 31, 2018	For the Year Ended December 31, 2019
	(In thousands)			
Swaps	$16,753	$1,267	$ 2,720	$43,944
Collars	—	(386)	7,745	3,440
Swaptions	—	—	—	4,351
	$16,753	$ 881	$10,465	$51,735

(12) Related Party Transactions

In February 2019, Comstock sold certain leases covering 1,464 undeveloped net acres in Caddo Parish, Louisiana for $5.9 million to a partnership owned by the Company's majority stockholder. The proceeds from the sale were used to fund the purchase of a like number of net acres from a third party for $5.9 million. The acreage acquired was in part the acreage sold to the partnership or acreage in the same area. The purchase price paid per net acre was determined by the price paid by the Company to the third party. As of December 31, 2019, Comstock had drilled nine wells, and completed four wells for the partnership. The remaining five wells will be completed in 2020. The Company operates and owns working interests in these properties along with the partnerships owned by the majority stockholder. Comstock also drilled six wells in South Texas that the Company does not have an interest in for another partnership owned by its majority stockholder. As operator, Comstock charges the partnerships for the costs incurred to drill and operate the wells as well as customary drilling and operating overhead fees that it charges other working interest owners. Comstock received $45.5 million from the partnerships for the year ended December 31, 2019 and had a $35.5 million receivable from the partnerships at December 31, 2019. The December 31, 2019 receivable was collected in full in 2020.

(13) Supplementary Quarterly Financial Data (Unaudited)

	2018				
	Predecessor			Successor	
	First	Second	July 1 through August 13	August 14 through September 30	Fourth
	(In thousands, except per share data)				
Total oil and gas sales	$ 72,593	$ 61,449	$ 32,588	$70,123	$153,498
Operating income (loss)	$ (5,122)	$ 7,716	$ 8,228	$34,581	$ 81,450
Net income (loss)	$(41,886)	$(34,003)	$(16,865)	$13,823	$ 50,299
Income (loss) per share:					
Basic and diluted	$ (2.78)	$ (2.23)	$ (1.09)	$ 0.13	$ 0.48

	2019			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
Total oil and gas sales	$126,881	$128,116	$224,444	$289,248
Operating income	$ 53,224	$ 43,621	$ 76,360	$101,681
Net income	$ 13,575	$ 21,407	$ 6,791	$ 55,116
Income (loss) per share:				
Basic	$ 0.13	$ 0.20	$ (0.01)	$ 0.22
Diluted	$ 0.13	$ 0.20	$ (0.01)	$ 0.19

The first quarter and second quarter of 2018 include loss on property sales of $28.6 million and $6.8 million, respectively. Basic and diluted per share amounts are the same for each of the quarters where a net loss was reported.

(14) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of oil and natural gas reserves:

	Predecessor				Successor			
	Year Ended December 31, 2017		Period from January 1, 2018 through August 13, 2018		Period from August 14, 2018 through December 31, 2018		Year Ended December 31, 2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:								
Beginning of period	7,277	872,468	7,552	1,116,956	28,994 [1]	2,246,501	23,612	2,282,758
Revisions of previous estimates	1,232	33,721	4	17,778	5	23,949	(4,621)	62,697
Extensions and discoveries	1	291,881	5,651	950,032	—	30,126	259	315,286
Acquisitions of minerals in place	—	—	—	220,088	—	33,612	240	3,023,109
Sales of minerals in place	(7)	(7,593)	(6,870)	(54,341)	(4,002)	(6,399)	(58)	(49,520)
Production	(951)	(73,521)	(287)	(55,240)	(1,385)	(45,031)	(2,685)	(292,833)
End of period	7,552	1,116,956	6,050	2,195,273	23,612	2,282,758	16,747	5,341,497
Proved Developed Reserves:								
Beginning of period	7,277	321,527	7,552	436,114	22,845 [1]	550,198	21,466	583,107
End of period	7,552	436,114	403	500,031	21,466	583,107	15,104	1,890,357
Proved Undeveloped Reserves:								
Beginning of period	—	550,941	—	680,842	6,149 [1]	1,696,303	2,146	1,699,651
End of period	—	680,842	5,647	1,695,242	2,146	1,699,651	1,643	3,451,140

	Predecessor				Successor			
	Year Ended December 31, 2017		Period from January 1, 2018 through August 13, 2018		Period from August 14, 2018 through December 31, 2018		Year Ended December 31, 2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Reserves associated with Assets Held for Sale:								
Proved Reserves								
Beginning of period	6,950	9,915	7,116	10,484				
End of period	7,116	10,484	—	—				
Proved Developed Reserves								
Beginning of period	6,950	9,915	7,116	10,484				
End of period	7,116	10,484	—	—				
Proved Undeveloped Reserves								
Beginning of period	—	—	—	—				
End of period	—	—	—	—				

(1) The beginning proved reserves balance represents the contributed Bakken shale properties and the reserves of the Predecessor on a combined basis.

The acquisitions of minerals in place in 2019 is primarily related to the Covey Park Acquisition.

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves:

	Predecessor		Successor	
	As of December 31, 2017	As of August 13, 2018	As of December 31, 2018	As of December 31, 2019
	(In thousands)			
Cash Flows Relating to Proved Reserves:				
Future Cash Flows	$ 3,588,764	$ 6,384,203	$ 8,054,092	$13,078,155
Future Costs:				
Production	(986,398)	(1,804,559)	(2,160,912)	(3,562,042)
Development and Abandonment	(672,559)	(1,945,141)	(1,800,335)	(3,171,351)
Future Income Taxes	5,239	(199,589)	(622,241)	(676,759)
Future Net Cash Flows	1,935,046	2,434,914	3,470,604	5,668,003
10% Discount Factor	(1,053,502)	(1,556,927)	(1,996,764)	(2,754,792)
Standardized Measure of Discounted Future Net Cash Flows	$ 881,544	$ 877,987	$ 1,473,840	$ 2,913,211
Standardized Measure of Discounted Future Net Cash Flows Related to Assets Held for Sale	$ 109,134	$ —	$ —	$ —

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves:

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
	(In thousands)			
Standardized Measure, Beginning of Year	$ 429,275	$ 881,544	$1,317,383	$1,473,840
Net change in sales price, net of production costs	326,662	(61,662)	223,731	(716,930)
Development costs incurred during the year which were previously estimated	119,864	86,086	112,073	311,331
Revisions of quantity estimates	57,042	19,815	27,090	16,340
Accretion of discount	43,130	53,413	55,692	175,514
Changes in future development and abandonment costs	(62,509)	(27,489)	23,139	(93,476)
Changes in timing and other	(15,565)	(17,723)	9,434	180,314
Extensions and discoveries	167,135	167,986	15,263	442,099
Acquisitions of minerals in place	—	72,738	54,143	1,813,491
Sales of minerals in place	(6,027)	(124,083)	(42,870)	(51,070)
Sales, net of production costs	(194,562)	(129,991)	(181,218)	(580,922)
Net changes in income taxes	17,099	(42,647)	(140,020)	(57,320)
Standardized Measure, End of Year	$ 881,544	$ 877,987	$1,473,840	$2,913,211

The standardized measure of discounted future net cash flows was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent prices received at the Company's sales point. These prices have been adjusted from posted or index prices for both location and quality differences.

Prices used in determining oil and natural gas reserves quantities and cash flows are as follows:

	Predecessor		Successor	
	Year Ended December 31, 2017	Period from January 1, 2018 through August 13, 2018	Period from August 14, 2018 through December 31, 2018	Year Ended December 31, 2019
Crude Oil: $/barrel	$48.71	$62.29	$61.21	$55.69
Natural Gas: $/Mcf	$ 2.88	$ 2.74	$ 2.90	$ 2.58

Proved reserve information utilized in the preparation of the financial statements were based on estimates prepared by our petroleum engineering staff in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of the Company's reserves are located onshore in the continental United States of America. We retained two independent petroleum consultants to conduct audits of our 2019 reserve estimates. The aggregate audited values of pre-tax discounted future net cash flows represented 100.0% of the pretax discounted values as of December 31, 2019. The purpose of these audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates. The engineering firms were selected for their geographic expertise and their historical experience.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

WEBSITE

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PRIMARY SUBSIDIARIES

Comstock Oil & Gas, LLC
Comstock Oil & Gas – Louisiana, LLC

INDEPENDENT PUBLIC ACCOUNTANTS

Ernst & Young LLP

INDEPENDENT PETROLEUM CONSULTANTS

Lee Keeling and Associates
Netherland, Sewell & Associates, Inc.

EXCHANGE LISTING

The Company's common stock is listed for trading on the New York Stock Exchange ("NYSE") under the symbol "CRK".

TRANSFER AGENT AND REGISTRAR

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CORPORATE GOVERNANCE AND EXECUTIVE CERTIFICATIONS

Our Corporate Governance Guidelines are available by selecting Investor Info on our web site at www.comstockresources.com. We have included as exhibits to our 2019 Annual Report on Form 10-K filed with the Securities and Exchange Commission, certificates of our chief executive officer and chief financial officer regarding the quality of our public disclosure. We have also submitted to the NYSE a certificate of our chief executive officer certifying that he is not aware of any violation by the company of the NYSE corporate governance listing standards.

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