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

FORM 10-K

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

For the fiscal year ended December 31, 2019

or

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

For the transition period from _______________ to _______________

Commission file number: **001-31899**

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**20-0098515**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Lincoln Street, Suite 4700 Denver, Colorado	**80203-4547**
(Address of principal executive offices)	(Zip code)

(303) 837-1661
(Registrant's telephone number, including area code)

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

Common Stock, $0.001 par value	**WLL**	**New York Stock Exchange**
(Title of each class)	(Trading Symbol)	(Name of each exchange on which registered)

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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	☒	Smaller reporting company	☐
Accelerated filer	☐	Emerging growth company	☐
Non-accelerated filer	☐		

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

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2019: $1,693,000,000.

Number of shares of the registrant's common stock outstanding at February 20, 2020: 91,813,908 shares.

DOCUMENTS INCORPORATED BY REFERENCE

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

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms "we", "us", "our" or "ours" when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

"ASC" Accounting Standards Codification.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

"Bcf" One billion cubic feet, used in reference to natural gas.

"BOE" One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

"Btu" or *"British thermal unit"* The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

"completion" The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

"costless collar" An option position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception. A collar can also contain an additional sold put option. Refer to "three-way collar" for more information.

"deterministic method" The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

"development well" A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"differential" The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"dry hole" or "dry well" A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

"EOR" Enhanced oil recovery.

"exploratory well" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"extension well" A well drilled to extend the limits of a known reservoir.

"FASB" Financial Accounting Standards Board.

"field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

"GAAP" Generally accepted accounting principles in the United States of America.

“gross acres” or “gross wells” The total acres or wells, as the case may be, in which a working interest is owned.

“ISDA” International Swaps and Derivatives Association, Inc.

“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil, NGLs or other liquid hydrocarbons.

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas.

“MMBbl” One million barrels of oil, NGLs or other liquid hydrocarbons.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units, used in reference to natural gas.

“MMcf” One million cubic feet, used in reference to natural gas.

“MMcf/d” One MMcf per day.

“net acres” or *“net wells”* The sum of the fractional working interests owned in gross acres or wells, as the case may be.

“net production” The total production attributable to our fractional working interest owned.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“PDNP” Proved developed nonproducing reserves.

“PDP” Proved developed producing reserves.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

“pre-tax PV10%” The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated lease operating expense, transportation, gathering, compression and other expense, production taxes and future development costs, using costs as of the date of estimation without future escalation and using an average of the first-day-of-the-month price for each of the 12 months within the fiscal year, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. Refer to the footnote to the Proved Reserves table in Item 1. “Business” of this Annual Report on Form 10-K for more information.

"probabilistic method" The method of estimating reserves using the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

"prospect" A property on which indications of oil or gas have been identified based on available seismic and geological information.

"proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

"proved reserves" Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

"proved undeveloped reserves" or "PUDs" Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"reasonable certainty" If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

“recompletion” An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

“reserves” Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“resource play” An expansive contiguous geographical area with known accumulations of crude oil or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and completion technologies.

“royalty” The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

“royalty interest” An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

“SEC” The United States Securities and Exchange Commission.

“standardized measure of discounted future net cash flows” or *“Standardized Measure”* The discounted future net cash flows relating to proved reserves based on the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period (unless prices are defined by contractual arrangements, excluding escalations based upon future conditions); current costs and statutory tax rates (to the extent applicable); and a 10% annual discount rate.

“three-way collar” A combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) to be received for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all associated risks.

“workover” Operations on a producing well to restore or increase production.

PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. We were incorporated in the state of Delaware in 2003 in connection with our initial public offering.

Since our inception, we have built a strong asset base through a combination of property acquisitions, development of proved reserves and exploration activities. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties, such as the acquisition discussed below under "Acquisitions and Divestitures," and exploring other basins where we can apply our existing knowledge and expertise to build production and add proved reserves. As a result of lower crude oil prices during 2017 and 2018, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2019, we focused on developing our large resource play in the Williston Basin of North Dakota and Montana, while continuing to closely align our capital spending with cash flows generated from operations. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under "Acquisitions and Divestitures."

As of December 31, 2019, our estimated proved reserves totaled 485.4 MMBOE and our 2019 average daily production was 125.5 MBOE/d, which results in an average reserve life of approximately 10.6 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2019 with the corresponding pre-tax PV10% values, our fourth quarter 2019 average daily production rates, and our total standardized measure of discounted future net cash flows as of December 31, 2019:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2019 Average Daily Production (MBOE/d)
Northern Rocky Mountains (3)	246.9	90.0	700.1	453.5	54%	$ 3,458	112.0
Central Rocky Mountains (4)	14.1	3.4	33.4	23.1	61%	206	10.4
Other (5)	7.3	0.4	6.5	8.8	83%	78	0.6
Total	**268.3**	**93.8**	**740.0**	**485.4**	**55%**	**$ 3,742**	**123.0**
Discounted Future Income Tax Expense						**(40)**	
Standardized Measure of Discounted Future Net Cash Flows						**$ 3,702**	

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from an oil price of $55.69 per Bbl and a gas price of $2.58 per MMBtu, which were calculated using an average of the first-day-of-the-month price for each month within the 12 months ended December 31, 2019 as required by current SEC and FASB guidelines.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (the "Standardized Measure"), which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the Standardized Measure but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors when evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment

related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the Standardized Measure. Our pre-tax PV10% and Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

(3) Includes oil and gas properties located in Montana and North Dakota.

(4) Includes oil and gas properties located in Colorado.

(5) Primarily includes non-core oil and gas properties located in Colorado, Mississippi, North Dakota, Texas and Wyoming.

During 2019, we incurred $778 million in exploration and development ("E&D") expenditures, including $772 million for the drilling and completion of 210 gross (94.0 net) wells.

Our current 2020 E&D budget is a range of $585 million to $620 million, which we expect to fund substantially with net cash provided by our operating activities and cash on hand. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate, adjust our E&D budget accordingly, enter into agreements with industry partners, divest certain oil and gas property interests, adjust borrowings outstanding under our credit facility or access the capital markets as necessary.

Acquisitions and Divestitures

2019 Acquisitions and Divestitures. In July 2019, we completed the divestiture of our interests in 137 non-operated, producing oil and gas wells located in McKenzie, Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $27 million (before closing adjustments).

In August 2019, we completed the divestiture of our interests in 58 non-operated, producing oil and gas wells located in Richland County, Montana and Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $26 million (before closing adjustments).

On a combined basis, the divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2018 and our April 2019 average daily production.

There were no significant acquisitions during the year ended December 31, 2019.

2018 Acquisitions and Divestitures. In July 2018, we completed the acquisition of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The producing properties had estimated proved reserves of 25.7 MMBOE as of the acquisition date, 84% of which were crude oil and NGLs.

There were no significant divestitures during the year ended December 31, 2018.

Subsequent to December 31, 2019, we completed the divestiture of our interests in 30 non-operated, producing oil and gas wells and related undeveloped acreage located in McKenzie County, North Dakota for aggregate sales proceeds of $25 million (before closing adjustments). The divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2019 and 1% of our average daily production for the year ended December 31, 2019.

Business Strategy

Our goal is to generate meaningful growth in shareholder value through the development, acquisition and exploration of oil and gas projects with attractive rates of return on capital. Specifically, we have focused, and plan to continue to focus, on the following:

Efficiently Developing Existing Properties. The development of our large resource play at our Williston Basin project in North Dakota and Montana continues to be our central objective. We have assembled approximately 756,800 gross (476,300 net) developed and undeveloped acres in this area, on which we had four drilling rigs operating as of December 31, 2019. During 2019, we completed and

brought on production 133 gross (87 net) operated Bakken and Three Forks wells in the Williston Basin. Under our current 2020 capital program, we expect to put on production approximately 122 gross wells in this area during the year.

At our Redtail field in the Denver-Julesburg Basin (the “DJ Basin”) in Weld County, Colorado, we have assembled approximately 96,400 gross (84,600 net) developed and undeveloped acres. We completed 22 drilled uncompleted wells (“DUCs”) in our Redtail field during the first half of 2018, and no additional wells were drilled or completed in 2019. During 2019 we worked on maintaining base production with improved artificial lift techniques and reductions in lease operating expenses.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of our exposure to commodity price volatility. We have historically funded our acquisition and growth activity through a combination of internally generated cash flows, equity and debt issuances, bank borrowings and certain oil and gas property divestitures, as appropriate, to maintain our financial position. As a result of lower crude oil prices during 2017 and 2018, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2019, we focused on developing our large resource play in the Williston Basin of North Dakota and Montana, while continuing to closely align our capital spending with cash flows generated from operations. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement or fund our E&D expenditures. For example, during 2019 we sold certain oil and gas properties operated by third parties that no longer matched the profile of properties we desire to own. In addition, to support cash flow generation on our existing properties and help ensure expected cash flows from newly acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and swaps to provide an attractive base commodity price level.

Growing Through Accretive Acquisitions. Since 2010, we have completed 7 separate significant acquisitions of producing properties for total estimated proved reserves of 240.2 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, business development, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, closing purchases and effectively managing the properties we acquire. We intend to selectively pursue the acquisition of properties that are complementary to our core operating areas, as well as explore opportunities in other basins where we can apply our existing knowledge and expertise to build production and add proved reserves.

Competitive Strengths

We believe that our key competitive strengths lie in our focused asset portfolio, our experienced management and technical teams and our commitment to the effective application of new technologies.

Focused, Long-Lived Asset Base. As of December 31, 2019, we had interests in 5,021 gross (2,171 net) productive wells on approximately 824,200 gross (523,600 net) developed acres across our geographical areas. We believe the concentration of our operated assets presents us with multiple opportunities to successfully execute our business strategy by enabling us to leverage our technical expertise and take advantage of operational efficiencies. Our proved reserve life is approximately 10.6 years based on year-end 2019 proved reserves and 2019 production.

Experienced Management and Technical Teams. Our management team averages 23 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, our team of acquisition professionals has an average of 20 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated extensive engineering, operational, geologic and geophysical technical knowledge. Our technical team has access to an abundance of digital well log, seismic, completion, production and other subsurface information, which is analyzed in order to accurately and efficiently characterize the anticipated performance of our oil and gas reservoirs. In addition, our information systems enable us to update our production databases through field automation. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

We continue to advance our completion techniques by utilizing customized, right-sized completion designs based on calibrated models for each of our prospect areas, using multivariate analysis to understand which completion factors most significantly impact the results in each area, and piloting and adopting the latest completion technologies available. Such customized designs utilize the optimum volume of proppant, diversion techniques, fluids and frac stages, allowing us to increase well performance while reducing cost. We

have increased stages pumped per day by focusing on new technologies such as quick-install wellhead connections and frac plug innovations. We plan to continue to use right-sized completion designs on wells we drill in 2020, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and evolving 3-D bit cutter technology to reduce time-on-location and total well cost.

Proved Reserves

Our estimated proved reserves as of December 31, 2019 are summarized by core area in the table below. Refer to "Reserves" in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures [1] (in millions)
Northern Rocky Mountains [2]						
PDP	169.8	67.9	534.8	326.7	72%	
PDNP	2.3	0.8	5.8	4.0	1%	
PUD	74.8	21.3	159.5	122.8	27%	
Total proved	**246.9**	**90.0**	**700.1**	**453.5**	**100%**	**$ 1,396**
Central Rocky Mountains [3]						
PDP	11.4	3.0	29.1	19.3	84%	
PUD	2.7	0.4	4.3	3.8	16%	
Total proved	**14.1**	**3.4**	**33.4**	**23.1**	**100%**	**$ 48**
Other [4]						
PDP	6.9	0.3	5.5	8.1	92%	
PDNP	0.4	0.1	1.0	0.7	8%	
Total proved	**7.3**	**0.4**	**6.5**	**8.8**	**100%**	**$ 8**
Total Company						
PDP	188.1	71.2	569.4	354.1	73%	
PDNP	2.7	0.9	6.8	4.7	1%	
PUD	77.5	21.7	163.8	126.6	26%	
Total proved	**268.3**	**93.8**	**740.0**	**485.4**	**100%**	**$ 1,452**

(1) Estimated future capital expenditures incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.

(2) Includes oil and gas properties located in Montana and North Dakota.

(3) Includes oil and gas properties located in Colorado.

(4) Primarily includes non-core oil and gas properties located in Colorado, Mississippi, North Dakota, Texas and Wyoming.

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline or rail takeaway. In areas where there is no practical access to gathering pipelines, oil is trucked or transported to terminals, market hubs, refineries or storage facilities. The tables below present percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2019, 2018 and 2017. We believe that the loss of any individual purchaser would not have a long-term material adverse impact on our financial position or results of operations, as alternative customers and markets for the sale of our products are readily available in the areas in which we operate.

Year Ended December 31, 2019	
Tesoro Crude Oil Co	14 %
Philips 66 Company	12 %
Year Ended December 31, 2018	
United Energy Trading, LLC	17 %
Tesoro Crude Oil Co	14 %
Philips 66 Company	11 %
Year Ended December 31, 2017	
Tesoro Crude Oil Co	18 %

Title to Properties

Our properties are subject to customary royalty interests, liens securing indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also collateralized by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory rights or title to all of our producing properties. As is customary in the oil and gas industry, limited investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

The oil and gas industry is a highly competitive environment for acquiring properties, obtaining investment capital, securing oil field goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our resources permit. In addition, the unavailability or high cost of drilling rigs or other equipment and services could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to obtain necessary capital as well as evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

In addition, the oil and gas industry as a whole competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources, such as wind, solar, nuclear and electric power, could adversely affect our revenue.

Regulation

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations that we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, NGLs and natural gas within its jurisdiction.

Currently, none of our production volumes are produced from offshore leases, however, some of our prior offshore operations were conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the "BOEM"). Among other things, BOEM regulations establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. The present value of our future abandonment obligations associated with offshore properties was $41 million as of December 31, 2019. We are therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act.

The Bureau of Land Management ("BLM") establishes the basis for onshore royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by the BLM and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

Regulation of Sale and Transportation of Oil

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices, however, Congress could reenact price controls or enact other legislation in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. The FERC's regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The most recent mandatory five-year review period resulted in a 2015 order from the FERC for the index to be based on Producer Price Index for Finished Goods (the "PPI-FG") plus a 1.23% adjustment for the five-year period from July 1, 2016 through June 30, 2021. This represents a decrease from the PPI-FG plus 2.65% adjustment from the prior five-year period. The FERC determined that it would now use a calculation based on what it determined to be a superior data source, reflecting actual cost-of-service data as opposed to the accounting data historically used as a proxy for such information under the prior index methodology. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. In addition, the FERC has emergency authority under the Interstate Commerce Act to intervene and direct priority use of oil pipeline transportation capacity, and the FERC exercised this authority over a specific pipeline in February 2014 in response to significant disruptions in the supply of propane. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Transportation and safety of oil and hazardous liquid is subject to regulation by the Department of Transportation (the "DOT") under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. The Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency within the DOT, enforces regulations on all interstate liquids transportation and some intrastate liquids transportation. The effect of regulatory changes under the DOT and their effect on interstate and intrastate oil and hazardous liquid transportation will not affect our operations in any way that is of material difference from those of our competitors.

A portion of our crude oil production may be shipped to market centers using rail transportation facilities owned and operated by third parties. The DOT, generally, and PHMSA, more specifically, establish safety regulations relating to crude-by-rail transportation. In addition, third-party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the DOT, the Federal

Railroad Administration (the "FRA") of the DOT, the Occupational Safety and Health Administration and other federal regulatory agencies.

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. In response to train derailments occurring in the United States and Canada in 2013 and 2014, U.S. regulators have taken a number of additional actions to address the safety risks of transporting crude oil by rail.

In February 2014, the DOT issued an emergency order requiring all persons to ensure crude oil is properly tested and classed prior to offering such product into transportation, and to assure all shipments by rail of crude oil be handled as a Packing Group I or II hazardous material. Also in February 2014, the Association of American Railroads entered into a voluntary agreement with the DOT to implement certain restrictions around the movement of crude oil by rail. In May 2014 (and extended indefinitely in May 2015), the DOT issued an Emergency Restriction/Prohibition Order requiring each railroad carrier operating trains transporting 1,000,000 gallons or more of Bakken crude oil to provide notice to state officials regarding the expected movement of the trains through the counties in each state. The PHMSA and FRA have also issued safety advisories and alerts regarding oil transportation and have issued a report focused on the increased volatility and flammability of Bakken crude oil as compared with other crudes in the U.S. In May 2015, PHMSA issued new rules applicable to "high-hazard flammable trains," defined as a continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed throughout a train. Among other requirements, the new rules require enhanced standards for newly constructed tank cars and retrofitting of existing tank cars, restricted operating speeds, a documented testing and sampling program, and routine assessments that evaluate certain safety and security factors. In December 2015, the Fixing America's Surface Transportation ("FAST") Act became law, further extending PHMSA's authority to improve the safety of transporting flammable liquids by rail and pursuant to which new regulations phasing out the use of certain older rail cars were finalized in August 2016. In June 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act became law. The PIPES Act strengthens PHMSA's safety authority, including an expansion of its ability to issue emergency orders, which was adopted by rule in October 2016 and further enhanced by rule in October 2019. PHMSA continues to review further potential new safety regulations under the PIPES Act and the FAST Act.

We do not currently own or operate rail transportation facilities or rail cars. However, the adoption of any regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the U.S., the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows. The effect of any such regulatory changes will not affect our operations in any way that is of material difference from those of our competitors.

Regulation of Transportation, Storage, Sale and Gathering of Natural Gas

The FERC regulates the transportation and, to a lesser extent, the sale of natural gas for resale in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. Regulations implemented by the FERC could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry has historically been heavily regulated. Therefore, we cannot provide

any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Transportation and safety of natural gas is subject to regulation by the DOT under the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. In addition, intrastate natural gas transportation is subject to enforcement by state regulatory agencies and PHMSA enforces regulations on interstate natural gas transportation. State regulatory agencies can also create their own transportation and safety regulations as long as they meet PHMSA's minimum requirements. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Likewise, the effect of regulatory changes by the DOT and their effect on interstate natural gas transportation will not affect our operations in any way that is of material difference from those of our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

In October 2015, a failure at an underground natural gas storage facility in Southern California prompted PHMSA to issue an advisory bulletin reminding owners and operators of underground storage facilities to review operations, identify the potential for facility leaks and failures and to review and update emergency plans. The State of California proclaimed the underground natural gas storage facility an emergency situation in January 2016. A federal task force was also convened to make recommendations to help avoid such failures. An interim final rule of PHMSA became effective in January 2017 which adopted certain specific industry recommended practices into Part 192 of the Federal Pipeline Safety Regulations. PHMSA later reopened the post-promulgation comment period through November 2017 in response to petitions for reconsideration and has stated it would consider such comments further when it adopts a final rule. Under the interim final rule, if an operator fails to take any measures recommended it would need to justify in its written procedures why the measure is impracticable and unnecessary. PHMSA regulations had previously covered much of the surface piping up to the wellhead at underground natural gas storage facilities served by pipelines and did not extend in part to the "downhole" portion of these facilities. The adopted requirements cover design, construction, material, testing, commissioning, reservoir monitoring and recordkeeping for existing and newly constructed underground natural gas storage facilities as well as procedures and practices for newly constructed and existing underground natural gas storage facilities, such as operations, maintenance, threat identification, monitoring, assessment, site security, emergency response and preparedness, training, recordkeeping and reporting. These regulations and any further increased attention to and requirements for underground storage safety and infrastructure by state and federal regulators that may result from this incident will not affect us in a way that materially differs from the way it affects other natural gas producers.

Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations to implement and enforce such laws, which often require costly compliance measures that carry substantial penalties for noncompliance. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences; restrict the types, quantities and concentrations of various materials that can be released into the environment; limit or prohibit project siting, construction or drilling activities on certain lands; require remedial and closure activities to prevent pollution from former operations; and impose substantial liabilities for unauthorized pollution. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in compliance, in all material respects, with current applicable environmental laws and regulations, future environmental enforcement remains a material risk due to the potential magnitude of exposure in the event of a noncompliance. We have incurred in the past, and expect to incur in the future, capital costs related to environmental compliance. Such expenditures are included within our overall capital budget and are not separately itemized.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), and comparable state laws impose strict joint and several liability for sites contaminated by certain hazardous substances on classes of potentially responsible persons. These persons include the owner or operator of the site where a release occurred and anyone who disposed of or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In the course of our ordinary operations, we may use, generate or handle material that may be regulated as "hazardous substances." Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites where these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we have used operating and disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on, under or from the properties owned or leased by us or on, under or from other locations where such substances have been taken for recycling or disposal. In addition, many of these owned and leased properties have been previously owned or operated by third parties whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control and not known to us. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices are similarly not under our control. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the problem itself is not discovered until years later. Current and formerly owned or operated properties, adjacent affected properties, offsite disposal facilities and substances disposed or released on them may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to investigate the source and extent of impacts from released hazardous substances;

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;

- to clean up and remediate contaminated property, including both soils and contaminated groundwater;

- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators; or

- to pay some or all of the costs of any such action.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA or any state analog.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee, permittee or holder of a right of use and easement of the area in which an offshore facility is located. OPA establishes a liability limit for onshore facilities of $350 million per spill, while the liability limit for offshore facilities is the payment of all removal costs plus $75 million per spill damages. These limits do not apply if the spill is caused by a responsible party's gross negligence or willful misconduct; the spill resulted from a responsible party's violation of a federal safety, construction or operating regulation; a responsible party fails to report a spill or to cooperate fully in a cleanup; or a responsible party fails to comply with an order issued under the authority of the Intervention on the High Seas Act. OPA requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million to cover liabilities related to an oil spill for which such responsible party is statutorily responsible. The President of the United States may increase the amount of financial responsibility required under OPA by up to $150 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative penalties. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Additionally, various federal, state and local agencies have jurisdiction over transportation, storage and disposal of hazardous waste and seek to regulate movement of hazardous waste in ways not preempted by federal law. We generate solid and hazardous wastes that are subject to RCRA and comparable state laws. Drilling fluid, produced water and many other wastes associated with the exploration, development and production of crude oil or natural gas are currently exempt from RCRA's hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be regulated as hazardous waste in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA, requesting it to reconsider the RCRA hazardous waste exemption for exploration, production and development wastes. In December 2016, the court entered a Consent Decree resolving the litigation, under which the EPA would issue such a rulemaking or make a determination that it was not necessary by March 15, 2019. In response, in April 2019, the EPA issued a determination that rulemaking to address waste from oil and gas exploration and production operations was not necessary at this time. However, it is possible that the EPA will take up such regulatory changes at a later date. Any such change in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes will continue to be regulated by state agencies as solid waste. Also, non-exempt waste streams generated by us will continue to be subject to existing onerous hazardous waste regulations. Although we do not believe the current costs of managing our wastes (as they are presently classified) to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act, or the Clean Water Act, as amended ("CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state waters or other waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

Where required, costs may be associated with the treatment of wastewater and/or the development and implementation of storm water pollution prevention plans. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of CWA and analogous state laws and regulations.

In addition, the CWA requires permits for discharges of dredged or filled materials into waters of the United States. These permits ("404 Permits") are under the joint jurisdiction of the EPA and the Army Corps of Engineers. 404 Permits may be required where development or construction activities have the potential to impact wetland areas that are considered waters of the United States. In 2015, the EPA greatly expanded the definition of waters of the United States. In doing so, it required 404 permits for disturbances in areas before not considered subject to United States CWA jurisdiction. However, effective December 23, 2019, the rule broadening the definition was repealed, ostensibly restoring jurisdiction to only those waterbodies (including wetlands) that have a "significant nexus" to navigable waters of the United States. Further rulemaking to refine the definition of waters of the United States is expected from the EPA in 2020. Any expansion of the scope of the CWA could increase costs associated with permitting and regulatory compliance. However, it is expected that any such change would not disparately affect us and our competitors.

Air Emissions. The Federal Clean Air Act, as amended (the "CAA"), and comparable state laws regulate emissions of various air pollutants from various industrial sources through air emissions permitting programs and also impose other monitoring and reporting requirements. New Source Performance Standards were promulgated for the oil and gas industry in 2012. These standards set limits for sulfur dioxide and volatile organic compound emissions and required application of reduced emission completion techniques by the industry. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining pre-construction and operating permits and approvals for air emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

In May 2016, the EPA issued a final rule regulating methane emissions from oil and natural gas operations (the "Subpart OOOOa Rule"). This rule applies to emissions from new, reconstructed and modified processes and equipment and also requires owners and operators to find and repair leaks to address fugitive emissions.

Certain states have also adopted, or are considering, regulations addressing methane releases from oil and gas operations. Colorado has adopted regulations reducing methane emissions from oil and gas operations. Compliance with rules applicable to jurisdictions in which we operate could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business.

However, in September 2019, the EPA proposed two alternative amendments to the Subpart OOOOa Rule. Both amendments would remove all methane-specific requirements from production and processing segments. The first amendment would also remove transportation and storage facilities from the definition of covered facilities. The comment period for the proposed rule closed on November 25, 2019. The net effect of either of these amendments, if finalized, would significantly reduce compliance obligations and associated costs.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of mainly water and sand plus a de minimis amount of chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We expect that we will utilize hydraulic fracturing for the foreseeable future to complete or recomplete wells in areas in which we work. Hydraulic fracturing is typically regulated at the state level; however, the EPA issued guidance in 2014 to address hydraulic fracturing injections using diesel.

In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA, along with other federal agencies such as the U.S. Department of Energy, the U.S. Government Accountability Office, the U.S. Department of Interior and the White House Council for Environmental Quality continue to study various aspects of hydraulic fracturing.

In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Multiple states, including Texas, Colorado and Wyoming have already adopted rules requiring disclosures of chemicals used in hydraulic fracturing and others have enacted regulations imposing additional requirements on activities involving hydraulic fracturing. Chemical disclosure regulations may increase compliance costs and may limit our ability to use cutting-edge technology in markets where disclosure is required. Further, laws such as those restricting the use of or regulating the time, place and manner of hydraulic fracturing (such as setback ordinances) may impact our ability to fully extract reserves. No assurance can be given as to whether or not such measures might be adopted in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities.

Further, in May 2014, the EPA published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. On July 11, 2014, the EPA extended the public comment period for the rulemaking to September 18, 2014. The EPA has not yet taken further action with respect to this rule. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties. In addition, we may be required to disclose information of third parties, that may be inaccurate or that we may be contractually prohibited from disclosing, which could also subject us to penalties.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study, as well as subsequent studies and reports, may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Global Warming and Climate Change. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and implemented regulations that restrict emissions of GHG under existing provisions of the CAA.

At present, the EPA may establish GHG permitting requirements for stationary sources already subject to the Prevention of Significant Deterioration ("PSD") and Title V requirements of the CAA. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions.

In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The public comment period for the rulemaking concluded on December 16, 2016. However, although the rulemaking remains on the EPA's long-term regulatory agenda, no final rule has been published.

In August 2015, the EPA issued a rule to reduce carbon emissions from electric generating units. The rule, commonly called the "Clean Power Plan", required states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2022, with the reductions to be fully phased in by 2030. However, in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it was being challenged in court. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan and on August 18, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule as a replacement to the Clean Power Plan. The EPA issued the final ACE rule in June 2019. As expected, over 20 states and public health and environmental organizations have challenged the rule. The EPA has sought expedited review in the hopes that the cases will be resolved by the summer of 2020. If the ACE rule were to become final, the costs of compliance are expected to be significantly less than they would have been under the Clean Power Plan.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. Also, in recent years, lawsuits have been brought against other energy companies for matters relating to climate change. Multiple states and localities have also initiated investigations in climate-change related matters. While the current suits focus on a variety of issues, at their core they seek compensation for the effects of climate change from companies with ties to GHG emissions. It is currently unknown what the outcome of these types of actions may be, but the costs of defending against such actions may be expected to rise. Finally, it should be noted that many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act ("OCSLA"), the National Environmental Policy Act ("NEPA") and the Coastal Zone Management Act ("CZMA"), require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires the U.S. Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and potentially an environmental impact statement. Recent federal court cases involving natural gas pipelines have involved challenges to the sufficiency of the evaluation of climate change impacts in environmental impact statements prepared under NEPA. The CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the U.S. Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Employees

As of January 31, 2020, we had approximately 505 full-time employees. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor’s own Internet access charges) through our website our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, including exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10-K, before making an investment decision with respect to our securities. In the event of the occurrence, reoccurrence, continuation or increased severity of any of the risks described below, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the level of global oil and natural gas inventories;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of oil and natural gas;
- market demand and capacity limitations on exports of oil and natural gas;
- political and economic conditions, including embargoes and sanctions, in oil-producing countries or affecting other oil-producing activity, such as the U.S. imposed sanctions on Venezuela and Iran and conflicts in the Middle East;
- developments of North American energy infrastructure;
- the level of global oil and natural gas exploration and production activity;
- the effects of global conservation and sustainability measures;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the effects of global and domestic economy, including the impact of expected growth, access to credit, financial and other economic issues;
- weather conditions;
- technological advances affecting energy consumption;
- current and anticipated changes to domestic and foreign governmental regulations, such as regulation of oil and natural gas gathering and transportation, including those that may arise as a result of the upcoming U.S. Presidential election;
- the price and availability of competitors' supplies of oil and natural gas;
- basis differentials associated with market conditions, the quality and location of production and other factors;
- acts of terrorism;
- the price and availability of alternative fuels; and

- acts of force majeure.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements. Also, prices for crude oil and prices for natural gas do not necessarily move in tandem. Declines in oil or natural gas prices would not only reduce revenue, but could also reduce the amount of oil and natural gas that we can economically produce and therefore potentially lower our oil and gas reserve quantities. If the oil and natural gas industry experiences extended periods of low prices, we may, among other things, be unable to meet all of our financial obligations or make planned expenditures.

Substantial and extended declines in oil, NGL and natural gas prices have resulted and may continue to result in impairments of our proved oil and gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending, sell assets or borrow to fund any such shortfall. Lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement. Upon a redetermination, if total outstanding credit exposure exceeds the redetermined borrowing base, we will be required to prepay outstanding borrowings in an aggregate principal amount equal to such excess in six substantially equal monthly installments.

Lower commodity prices may also make it more difficult for us to comply with the covenants and other restrictions in the agreements governing our debt as described under the risk factor entitled “The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.”

Alternatively, higher oil, NGL and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition, results of operations or cash flows.

Our future success will depend on the success of our exploration, development and production activities. Our oil and natural gas exploration and development activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Refer to the risk factor entitled “Reserve estimates depend on many assumptions that may turn out to be inaccurate...” for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including, but not limited to, the following:

- substantial or extended declines in oil, NGL and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits by state agencies or on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- pipeline takeaway and refining and processing capacity;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services;
- equipment failures or accidents;

- adverse weather events, such as floods, blizzards, ice storms, tornadoes and freezing temperatures; and
- title defects.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2019, we had outstanding $262 million of 1.25% Convertible Senior Notes due April 2020 and $2.2 billion of senior notes, which consisted of $774 million of 5.75% Senior Notes due March 2021, $408 million of 6.25% Senior Notes due April 2023 and $1,000 million of 6.625% Senior Notes due January 2026. We had $375 million of borrowings and $2 million in letters of credit outstanding under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit facility with $1.4 billion of available borrowing capacity. The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 1.25% Convertible Senior Notes due April 2020) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. We are allowed to incur additional indebtedness, provided that we meet certain requirements in the indentures governing our senior notes and Whiting Oil and Gas' credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including, but not limited to:

- making it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under Whiting Oil and Gas' credit agreement and the indentures governing our senior notes and convertible senior notes;
- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- increasing the possibility that we may be unable to generate sufficient cash to pay, when due, the principal of, interest on or other amounts due or otherwise refinance our indebtedness;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas' credit agreement is subject to certain rate variability;
- making us more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices; and
- reducing our borrowing base when oil and natural gas prices decline and our ability to maintain compliance with our financial covenants becomes more difficult, which may reduce or eliminate our ability to fund our operations.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Refer to the risk factor entitled "The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business."

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

Our earnings and cash flow could vary significantly from year to year due to the volatility of oil and natural gas prices. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and service our debt. Factors that may cause us to generate cash flow that is insufficient to meet our debt obligations include the events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. If we do not generate sufficient cash flow from operations to service our outstanding indebtedness, or if future borrowings are not available to us in an amount sufficient to enable us to pay or refinance our indebtedness, we may be required to undertake various alternative financing plans, which may include:

- refinancing or restructuring all or a portion of our debt;
- seeking alternative financing or additional capital investment;
- selling strategic assets;
- reducing or delaying capital investments; or
- revising or delaying our strategic plans.

We cannot assure you that we would be able to implement any of the above alternative financing plans, if necessary, on commercially reasonable terms or at all. If we cannot make scheduled payments on our indebtedness or otherwise fail to comply with the covenants and other restrictions in the agreements governing our debt, we will be in default and the lenders under Whiting Oil and Gas' credit agreement and the holders of our senior notes and convertible senior notes could declare all outstanding principal and interest to be due and payable. Additionally, the lenders under Whiting Oil and Gas' credit agreement could terminate their commitments to loan money and could foreclose against our assets collateralizing our borrowings, and we could be forced into bankruptcy or liquidation. If the amounts outstanding under any of our significant indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the amounts owed to the lenders or to our other debt holders. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our business, financial position, results of operations and cash flows.

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

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects.

Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results. Refer to the Risk Factor entitled "Negative public perception regarding us and/or our industry could have an adverse effect on our operations."

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior notes and convertible senior notes and Whiting Oil and Gas' credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements limit our and our subsidiaries' ability to, among other things:

- prepay, redeem or repurchase certain debt;

- pay dividends or make other distributions or repurchase or redeem our capital stock;
- make loans and investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- sell assets;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts; and
- create unrestricted subsidiaries.

In addition, Whiting Oil and Gas' credit agreement requires us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. Also, the indentures under which we issued our senior notes restrict us from incurring additional indebtedness and making certain restricted payments, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1.0. Factors that may adversely affect our ability to comply with these covenants include oil or natural gas price declines, lack of liquidity in property and capital markets and our inability to execute on our business plan.

If we fail to comply with the restrictions in the indentures governing our senior notes and convertible senior notes, Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us. Furthermore, if we were unable to repay the amounts due and payable under Whiting Oil and Gas' credit agreement, those lenders could proceed against the collateral granted to them to secure that indebtedness. In the event that our lenders or noteholders accelerate the repayment of our borrowings, we and our subsidiaries may not have sufficient assets or be able to borrow sufficient funds to repay or refinance that indebtedness. Also, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is redetermined on May 1 and November 1 of each year, and may be the subject of special redeterminations described in such credit agreement based on an evaluation of our oil and gas reserves. Because oil and gas prices are principal inputs into the valuation of our reserves, if oil and gas prices decline, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination, if total outstanding credit exposure exceeds the redetermined borrowing base, we will be required to prepay outstanding borrowings in an aggregate principal amount equal to such excess in six substantially equal monthly installments. We may not have sufficient funds to make such repayments.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and a failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our business, financial condition, results of operations or cash flows.

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our business including well development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also consider our likely sources of capital, including cash generated from operations and borrowings under Whiting Oil and Gas' credit

agreement. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

A large portion of our producing properties are concentrated in the Williston Basin of North Dakota and Montana, making us vulnerable to risks associated with operating in one major geographic area.

A large portion of our producing properties are geographically concentrated in the Williston Basin of North Dakota and Montana. At December 31, 2019, approximately 93% of our total estimated proved reserves were attributable to properties located in this area. Because of this concentration in a limited geographic area, the success and profitability of our operations may be disproportionately exposed to regional factors compared to competitors having more geographically dispersed operations. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints, (ii) the availability of rigs, equipment, oilfield services, supplies and labor, (iii) the availability of processing and refining facilities and (iv) infrastructure capacity. In addition, our operations in the Williston Basin may be adversely affected by severe weather events such as floods, blizzards, ice storms, tornadoes and freezing temperatures which can intensify competition for the items and services described above and may result in periodic shortages. The concentration of our operations in a limited geographic area also increases our exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife and unexpected events that may occur in the regions such as natural disasters, seismic events (which may result in third-party lawsuits), industrial accidents, labor difficulties, civil disturbances, public protests or terrorist attacks. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our business, financial condition, results of operations and cash flows.

If oil, NGL and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews (which may include depressed oil, NGL and natural gas prices and the continuing evaluation of development plans, production data, economics, possible asset sales and other factors) we may be required to write down the carrying value of our oil and gas properties. For example, we recorded an $835 million impairment charge during 2017 for the partial write-down of the Redtail field in Colorado. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our business, financial condition, results of operations or cash flows in the period recognized.

We may continue to incur cash and noncash charges that would negatively impact our future results of operations and liquidity.

While executing our strategic priorities to reduce financial leverage and complexity and to lower our capital expenditures in the face of lower commodity prices, we have incurred certain cash charges. As we continue to focus on our strategic priorities, we may incur additional cash and noncash charges in the future. If incurred, these charges could have a material adverse effect on our liquidity and results of operations in the period recognized.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight rock formations. The process involves the injection of mainly water and sand plus a de minimis amount of chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We expect that we will utilize hydraulic fracturing for the foreseeable future to complete or recomplete wells in the areas in which we work. Hydraulic fracturing is typically regulated at the state level, however, the U.S. Environmental Protection Agency (the "EPA") issued guidance in 2014 to address hydraulic fracturing injections involving diesel. In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA,

along with other federal agencies such as the U.S. Department of Energy, the U.S. Government Accountability Office, the U.S. Department of Interior and the White House Council for Environmental Quality continue to study various aspects of hydraulic fracturing.

In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Multiple states, including Texas, Colorado and Wyoming have already adopted rules requiring disclosures of chemicals used in hydraulic fracturing and others have enacted regulations imposing additional requirements on activities involving hydraulic fracturing. Chemical disclosure regulations may increase compliance costs and may limit our ability to use cutting-edge technology in markets where disclosure is required. Further, laws such as those restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing (such as setback ordinances) may impact our ability to fully extract reserves. No assurance can be given as to whether or not such measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could prohibit or make it more difficult or costly for us to perform hydraulic fracturing activities.

Further, in May 2014, the EPA published an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act, relating to the disclosure of chemical substances and mixtures used in oil and gas exploration and production. On July 11, 2014, the EPA extended the public comment period for the rulemaking to September 18, 2014. The EPA has not yet taken further action with respect to this rule. Depending on the precise disclosure requirements the EPA elects to impose, if any, we may be obliged to disclose valuable proprietary information, and failure to do so may subject us to penalties. In addition, we may be required to disclose information of third parties, which may be inaccurate or which we may be contractually prohibited from disclosing, which could also subject us to penalties.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a connection between the deep well injection of hydraulic fracturing wastewater and a sharp increase in seismic activity in Oklahoma since 2008. This study, as well as subsequent studies and reports, may trigger new legislation or regulations that would limit or ban the disposal of hydraulic fracturing wastewater in deep injection wells. If such new laws or rules are adopted, our operations may be curtailed while alternative treatment and disposal methods are developed and approved.

Refer to “Hydraulic Fracturing” in Item 2 of this Annual Report on Form 10-K for more information on hydraulic fracturing.

We have entered into physical delivery contracts and do not expect to be able to deliver all the oil required under such contracts and, as a result, we expect we will be required to make deficiency payments.

As of December 31, 2019, we had three physical delivery contracts which require us to deliver fixed volumes of crude oil. One of these contracts is tied to oil production at our Sanish field in Mountrail County, North Dakota, the second is tied to oil production in the Williston Basin and the third is tied to oil production at our Redtail field in Weld County, Colorado. Although we believe that our production and reserves are sufficient to fulfill the delivery commitments at our Sanish field in North Dakota and the Williston Basin, if we fail to deliver the committed volumes, we would be required to pay deficiency payments of $7.00 and $5.75, respectively, per undelivered barrel (subject to upward adjustment). At our Redtail field, we have determined that it is not probable that future oil production will be sufficient to meet the minimum volume requirements under the contract in this area. We expect to make periodic deficiency payments under the Redtail contract that currently total $5.24 per undelivered Bbl through the April 2020 termination date. During 2019, 2018 and 2017, total deficiency payments under this contract amounted to $64 million, $37 million and $42 million, respectively. Refer to “Properties – Delivery Commitments” for more information about these delivery contracts.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as the following, among others:

- historical production from the area compared with production rates from other producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future prices of oil, NGLs and natural gas including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production, oil, NGL and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. The 12-month average prices used for the year ended December 31, 2019 were $55.69 per Bbl of oil and $2.58 per MMBtu of natural gas. Actual future prices and costs may differ materially from those used in the estimate. If the 12-month average oil prices used to calculate our oil reserves decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2019 would have decreased by $137 million. If the 12-month average natural gas prices used to calculate our natural gas reserves decline by $0.10 per MMBtu, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2019 would have decreased by $41 million.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of internally generated cash flows, equity and debt issuances, bank borrowings, agreements with industry partners and oil and gas property divestments. We intend to finance future capital expenditures substantially with cash flow from operations, cash on hand, borrowings under our credit agreement and proceeds from asset divestitures. Our cash flow from operations and access to capital is subject to a number of variables, including, but not limited to:

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

If our revenues or the borrowing base under our credit agreement decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves, or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels.

We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing. Disruptions in the capital and credit markets, particularly in the energy sector, could limit our ability to access these markets

or may significantly increase our cost to borrow. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the inability to access the cash and credit markets to obtain additional financing, on favorable terms or otherwise, could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, we may not be able to sustain production.

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline over time. Producing oil and natural gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and producing our current reserves and finding economically recoverable or acquiring additional economically recoverable reserves. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies or properties. Therefore, we may not be able to develop, find or acquire additional reserves to sustain or replace our current and future production, which could adversely affect our business, financial condition, results of operations or cash flows.

Our credit rating could negatively impact our availability and cost of capital and could require us to post more collateral under certain commercial arrangements.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, transportation, processing and hedging agreements. These collateral requirements depend, in part, on our credit rating. We may be requested or required by other counterparties to post additional collateral, which may be in the form of additional letters of credit, cash or other acceptable collateral. Any downgrade to our credit ratings could impact the posting of collateral consisting of cash or letters of credit, which would reduce availability under our credit agreement and negatively impact our liquidity.

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

In connection with our continued development of oil and gas properties, we are exposed to the impact of delays or interruptions of production from wells on these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas, downstream market conditions and competing supply alternatives. Our ability to market our production also depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties and the ability to obtain such services on acceptable terms. We may be disproportionately exposed to the impact of delays or interruptions of production caused by market constraints or the interruption of transporting oil and gas produced. This could lead to production curtailments or shut-ins, and reduced revenue which could materially harm our business. We may enter into arrangements for transportation services and sales to reduce curtailment risks. However, these services expose us to the risk that third parties will default on their obligations under such arrangements.

Risks associated with the production, gathering, transportation and sale of oil, NGLs and natural gas could adversely affect net income and cash flows.

Our net income and cash flows will depend upon, among other things, oil, NGL and natural gas production and the prices received and costs incurred to develop and produce oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, NGLs and natural gas will decrease revenues and increase expenditures. For example, accidents may occur that result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any costs incurred in connection with any such accidents that are not insured against will have the effect of reducing net income. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Also, our oil, NGL and natural gas production depends in large part on the proximity and capacity of pipeline systems and transportation facilities which are mostly owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. Similarly, curtailments or damage to pipelines and other transportation facilities used to transport oil, NGL and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailments or damage to the gathering systems could also require finding

alternative means to transport oil, NGL and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, accidents involving rail cars could result in significant personal injuries and property and environmental damage. In May 2015, the Pipeline and Hazardous Material Safety Administration issued new rules applicable to "high-hazard flammable trains", discussed in "Item 1 Business – Regulation – Regulation of Sale and Transportation of Oil" above, which could increase transportation expenses. Similarly, regulatory responses to the October 2015 failure at a Southern California underground natural gas storage facility could also lead to increased expenses for underground storage.

In addition, drilling, production and transportation of hydrocarbons bear the inherent risk of loss of containment. Potential consequences include, but are not limited to, loss of reserves, loss of production, loss of economic value associated with the affected wellbore, personal injuries and death, contamination of air, soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Part of our business strategy includes selling properties which subjects us to various risks.

Part of our business strategy includes selling properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own. However, there is no assurance that such sales will occur in the time frames or with the economic terms we expect. Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, divestitures of our properties will reduce our proved reserves and potentially our production. We may not be able to develop, find or acquire additional reserves sufficient to replace such reserves and production from any of the properties we sell. Additionally, agreements pursuant to which we sell properties may include terms that survive closing of the sale, including but not limited to indemnification provisions, which could result in us retaining substantial liabilities.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. Failure to drill sufficient wells in order to hold acreage will result in substantial lease renewal costs, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established on our undeveloped acreage, the underlying leases will expire. As of December 31, 2019, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 18% in 2020, 13% in 2021 and 15% in 2022. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations or cash flows.

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

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs, completion crews and other oilfield equipment as demand for these items has increased along with the number of wells being drilled and completed. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs and other oilfield goods and services. Shortages of field personnel and other professionals, drilling rigs, completion crews, equipment or supplies or price increases could delay or adversely affect our exploration and development operations, which could restrict such operations or have a material adverse effect on our business, financial condition, results of operations or cash flows.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field

goods and services, drilling results, our ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could in turn adversely affect our business, financial condition, results of operations or cash flows or require us to remove certain proved undeveloped reserves from our proved reserve base if we are unable to drill those PUD locations within the SEC's 5-year window.

Weaker price differentials and/or weaker benchmark prices of oil and natural gas and the wellhead price we receive could have a material adverse effect on our business, financial condition, results of operations or cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount, but sometimes at a premium, to the relevant benchmark prices such as NYMEX. A negative or positive difference between the benchmark price and the price received is called a differential. The differential may vary significantly due to market conditions, the quality and location of production and other risk factors, as demonstrated in the fourth quarter of 2018 when our oil differentials weakened substantially. We cannot accurately predict oil and natural gas differentials. Changes in the differential and decreases in the benchmark price for oil and natural gas could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain indemnities from sellers for liabilities they may have created.

Our business strategy includes a continuing acquisition program. From 2010 through 2019, we completed 7 separate significant acquisitions of producing properties with a combined purchase price of $4.6 billion for estimated proved reserves as of the effective dates of the acquisitions of 240.2 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including, but not limited to, the following:

- the anticipated levels of recoverable reserves, earnings or cash flow;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- the assumption of unknown potential environmental and other liabilities, losses or costs, including for example, title defects, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

Furthermore, acquisitions pose substantial risks to our business, financial condition, results of operations and cash flows. The risks associated with acquisitions, either completed or future acquisitions, include, but are not limited to:

- we may be unable to integrate acquired businesses successfully and to realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities in order to fund future acquisitions.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination,

when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our use of oil and natural gas price hedging contracts involves only a portion of our anticipated production, may limit higher revenues in the future in connection with commodity price increases and may result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas options contracts, primarily costless collars and swaps, placed with major financial institutions. As of February 20, 2020, we had contracts covering the sale of 31 MMBbl of oil per day for the remainder of 2020 and 6 MMBbl of oil per day for all of 2021. All of our oil hedges will expire by December 2021. Refer to “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A and the “Derivative Financial Instruments” footnote of the consolidated financial statements in Item 8 of this Annual Report on Form 10-K for pricing information and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Our three-way collars only provide partial protection against declines in market prices due to the fact that when the market price falls below the sub-floor, the minimum price we will receive will be NYMEX plus the difference between the floor and sub-floor. Furthermore, if we do not engage in hedging transactions or unwind hedging transactions we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income (loss). Consequently, we may experience significant net losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during certain months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations, cause temporary declines in our oil and gas production and materially increase our operating and capital costs.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, results of operations or cash flows. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- the loss of well control;

- fires and explosions;
- personal injuries and death;
- terrorist attacks; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues and increase capital expenditures.

We operate 88% of our net productive oil and natural gas wells, which represents 92% of our proved developed producing reserves as of December 31, 2019. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of our properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in, or a sustained period of low, oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use reasonable efforts to cause the operator to act in a prudent manner, we are limited in our ability to do so.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, the value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

Our drilling results in undeveloped acreage in new or emerging plays are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during 2018 we recorded an $8 million non-cash charge for the impairment of undeveloped oil and gas properties where we have no current or future plans to drill. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. Refer to "Acreage" in Item 2 of this Annual Report on Form 10-K for more information relating to the expiration of our rights to develop undeveloped acreage.

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

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include, but are not limited to:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;

- well spacing;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and litigation. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition, results of operations or cash flows. Strict liability or joint and several liability may be imposed under certain laws, which could cause us to become liable for the conduct of others or for consequences of our own actions. For instance, an accidental release from one of our wells could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations.

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentration of materials that can be released into the environment; limit or prohibit drilling activities on certain lands; and impose substantial liabilities for unauthorized discharges. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations, the imposition of injunctive relief, or certain leases could be cancelled in the event that an agency refuses to issue or delays the issuance of a required permit. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previous contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Private parties, including the surface owners of properties upon which we drill, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. Compliance with any enacted rules could result in significant costs, including increased capital expenditures and operating costs, which may adversely impact our business. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance of environmental laws and regulations.

For example, in 2012, the EPA published final rules under the Federal Clean Air Act (the “CAA”) that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. With regard to production activities, these rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells for which well completion operations are conducted and, in particular, requiring some of these wells to use reduced emission completions, also known as “green completions”, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels.

The requirements were further expanded again in 2016 when the implementation of Subpart OOOOa applied limits on methane emissions to oil and gas facilities and required operators to address leaks, also known as “fugitive emissions.”

However, in September 2019, the EPA proposed two alternative amendments to the Subpart OOOOa Rule. Both amendments remove all methane-specific requirements from production and processing segments. The first amendment would also remove transportation and storage facilities from the definition of covered facilities. The comment period for proposed rule closed on November 25, 2019. The net effect of any of these amendments, if finalized, would significantly reduce compliance obligations and associated costs.

The enactment of Senate Bill 19-181 "Protect Public Welfare Oil And Gas Operations" increased the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

In Colorado, on April 16, 2019, Governor Polis signed into law the final version of Senate Bill 19-181 ("SB 181"), known as the "Protect Public Welfare Oil and Gas Operations" legislation. SB 181 amends the Oil and Gas Conservation Act and other statutes to change the manner in which oil and gas development is regulated in Colorado and provide the opportunity for greater control to local governments. The amendments include changes to expand the authority of local governments relating to oil and gas development, as well as rulemaking requirements involving the Colorado Oil and Gas Conservation Commission ("COGCC") and the Air Quality Control Commission ("AQCC") that could include more stringent air emission limits for pollutants such as methane and volatile organic carbons and more rigorous permitting requirements. In December 2019, Colorado's AQCC adopted new rules targeting air emissions from upstream oil and gas operations, and depending on the results of other ongoing and upcoming rulemakings and actions by COGCC, the Colorado Department of Public Health and Environment and local jurisdictions, SB 181 could result in greater restrictions with respect to oil and gas development in Colorado, which could have a material adverse effect on our business, financial condition, results of operations or cash flows. Efforts similar to SB 181 are likely to continue in the future, which, if successful, could result in dramatically reducing the area available for future oil and gas development or outright banning oil and gas development in certain jurisdictions. We cannot predict the nature or outcome of future ballot initiatives, legislative actions or other similar efforts, or the effects of implementation of these efforts by local governments. If we are required to cease operating in any of the areas in which we now operate as the result of bans or moratoria on drilling or related oilfield services activities, it could have a material effect on our business, financial condition, and results of operations.

Issues surrounding climate change and greenhouse gas emissions could result in increased operating costs and reduced demand for oil and gas that we produce.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and implemented regulations that restrict emissions of GHG under existing provisions of the CAA.

At present, the EPA may establish GHG permitting requirements for stationary sources already subject to the Prevention of Significant Deterioration ("PSD") and Title V requirements of the CAA. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHGs. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions.

In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The public comment period for the rulemaking concluded on December 16, 2016. However, although the rulemaking remains on the EPA's long-term regulatory agenda, no final rule has been published.

In August 2015, the EPA issued a rule to reduce carbon emissions from electric generating units. The rule, commonly called the "Clean Power Plan", requires states to develop plans to reduce carbon emissions from fossil fuel-fired generating units commencing in 2022, with the reductions to be fully phased in by 2030. However, in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it was being challenged in court. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan and on August 18, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule as a replacement to the Clean Power Plan. The EPA issued the final ACE rule in June 2019. As expected, over 20 states and public health and environmental organizations have already challenged the rule. The EPA has sought expedited review in the hopes that the cases will be resolved by the summer of 2020.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved.

Also, in recent years, lawsuits have been brought against other energy companies for matters relating to climate change. Multiple states and localities have also initiated investigations in climate-change related matters. While the current suits focus on a variety of issues, at

their core they seek compensation for the effects of climate change from companies with ties to GHG emissions. It is currently unknown what the outcome of these types of actions may be, but the costs of defending against such actions may rise. Finally, many scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

A low ESG or sustainability score could result in the exclusion of our common shares from consideration by certain investment funds and a negative perception of us by certain investors.

Certain organizations that provide corporate governance and other corporate risk information to investors and shareholders have developed scores and ratings to evaluate companies and investment funds based upon environmental, social and governance ("ESG") or sustainability metrics. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and shareholders. Many investment funds focus on positive ESG business practices and sustainability scores when making investments. In addition, investors, particularly institutional investors, use these scores to benchmark companies against their peers and if a company is perceived as lagging, these investors may engage with companies to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company's sustainability score as a reputational or other factor in making an investment decision. Consequently, a low sustainability score could result in exclusion of our common shares from consideration by certain investment funds, engagement by investors seeking to improve such scores and a negative perception of us by certain investors.

We may be negatively impacted by litigation and legal proceedings.

We are subject from time to time, and in the future may become subject, to litigation claims. These claims and legal proceedings are typically claims that arise in the normal course of business and include, without limitation, claims relating to environmental, safety and health matters, commercial or contractual disputes with suppliers and customers, claims regarding ownership of mineral interests, including from royalty owners, claims regarding acquisitions and divestitures, regulatory matters and employment and labor matters. We may also become subject to governmental or regulatory proceedings. The outcome of such claims and legal proceedings cannot be predicted with certainty and some may be disposed of unfavorably to us. Among other pending litigation claims, the Company is involved with litigation related to a payment arrangement with a third party which currently claims damages up to $41 million, as well as court costs and interest. We also may not have insurance that covers such claims and legal proceedings. Successful claims or litigation against us for significant amounts could have a material adverse effect on our reputation, business, financial condition, results of operations and cash flows. Further, even if successful in resolving a claim or legal proceeding, such process could require the attention of members of our senior management, reducing the time they have available to devote to managing our business, and require us to incur substantial legal expenses.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Bradley J. Holly, Chairman, President and Chief Executive Officer; Bruce DeBoer, Chief Administrative Officer, General Counsel and Corporate Secretary; Charles J. Rimer, Chief Operating Officer; Correne S. Loeffler, Chief Financial Officer; and Timothy M. Sulser, Chief Corporate Development and Strategy Officer, could have a material adverse effect on our business, financial condition, results of operations or cash flows. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We expect to consider from time to time further strategic opportunities that may involve acquisitions, dispositions, investments in joint ventures, partnerships, and other strategic alternatives that may enhance shareholder value, any of which may result in the use of a significant amount of our management resources or significant costs, and we may not be able to fully realize the potential benefit of such transactions.

We expect to continue to consider acquisitions, dispositions, investments in joint ventures, partnerships, and other strategic alternatives with the objective of maximizing shareholder value. The Board and our management may from time to time be engaged in evaluating potential transactions and other strategic alternatives. In addition, from time to time, we may engage financial advisors, enter into non-disclosure agreements, conduct discussions, and undertake other actions that may result in one or more transactions. Although there would be uncertainty that any of these activities or discussions would result in definitive agreements or the completion of any transaction, we may devote a significant amount of our management resources to analyzing and pursuing such a transaction, which could negatively impact our operations, and may impair our ability to retain and motivate key personnel. In addition, we may incur significant costs in connection with seeking such transactions or other strategic alternatives regardless of whether the transaction is completed. In the event that we consummate an acquisition, disposition, partnership or other or strategic alternative in the future, we cannot be certain that we would fully realize the potential benefit of such a transaction and cannot predict the impact that such strategic transaction might have on our operations or stock price. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, regulatory limitations and the interest of third parties in us and our assets. There can be no assurance that the exploration of strategic alternatives will result in any specific action or transaction. Further, any such strategic alternative may not ultimately lead to increased shareholder value. We do not undertake to provide updates or make further comments regarding the evaluation of strategic alternatives, unless otherwise required by law.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for additional future acquisitions or other transactions on economically acceptable terms or at all.

Competition in the oil and gas industry and from alternative energy sources is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, obtaining investment capital, securing oilfield goods and services, marketing oil and natural gas products and attracting and retaining qualified personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our resources allow. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We also face indirect competition from alternative energy sources, including wind, solar, nuclear and electric power. The proliferation of alternative energy sources and businesses that provide such alternative energy sources may decrease the demand for oil and natural gas products. Decreased demand for our products could adversely affect our business, financial condition, results of operations or cash flows.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions, such as us, to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, may be established through rulemakings. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

We depend on computer and telecommunications systems, and failures in our systems or cybersecurity attacks could have an adverse effect on our business, financial condition, results of operations or cash flows.

Our business has become increasingly dependent upon digital technologies to conduct day-to-day operations, including information systems, infrastructure and cloud applications. We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. We rely on such systems to process, transmit and store electronic information, including financial records and personally identifiable information such as contractor, investor and payroll data, and to manage or support a variety of business processes, including our supply chain, pipeline operations, gathering and processing operations, financial transactions, banking and numerous other processes and transactions.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, also have increased in frequency. A cyber-attack could include unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. It is possible that we could incur interruptions from cybersecurity attacks, computer viruses or malware, or that third party service providers could cause a breach of our data. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls over personally identifiable information and contractor data; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations.

Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future cyber-attacks than other targets. The various procedures, facilities, infrastructure and controls we utilize to monitor these threats and mitigate our exposure to such threats are costly and labor intensive. Moreover, there can be no assurance that such measures will be sufficient to prevent security breaches from occurring. We do not expect to obtain or maintain specialized insurance for possible liability or loss resulting from a cyber-attack on our assets that may shut down all or part of our business. However, as cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. State and federal cybersecurity legislation could also impose new requirements, which could increase our cost of doing business.

To our knowledge we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third party

vendors and service providers. A cyber incident involving our information systems and related infrastructure, or that of third parties, could disrupt our business plans and negatively impact our operations in the following ways, among others, any of which could have an adverse effect on our reputation, business, financial condition, results of operations or cash flows:

- unauthorized disclosure of sensitive or personally identifiable information, including by cyber-attacks or other security breaches, could cause loss of data, give rise to remediation or other expenses, expose us to liability under federal and state laws, reduce our customers' willingness to do business with us, disrupt the services we provide to customers and subject us to litigation and investigations;
- a cyber-attack on a third party could result in supply chain disruptions which could delay or halt development of additional infrastructure, effectively delaying the start of cash flow from the project;
- a cyber-attack on downstream or midstream pipelines could prevent us from delivering product, resulting in a loss of revenues;
- a cyber-attack on a communications network or power grid could cause operational disruption resulting in a loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties; and
- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common shares.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Northern Rocky Mountains

Our Northern Rocky Mountains operations include our properties in the Williston Basin of North Dakota and Montana targeting the Bakken and Three Forks formations and encompassing approximately 756,800 gross (476,300 net) developed and undeveloped acres as of December 31, 2019. Our estimated proved reserves in the Northern Rocky Mountains as of December 31, 2019 were 453.5 MMBOE (54% oil), which represented 93% of our total estimated proved reserves and contributed 112.0 MBOE/d of average daily production in the fourth quarter of 2019.

Across our acreage in the Williston Basin, we have implemented customized, right-sized completion designs which utilize the optimum volume of proppant, diversion, fluids and frac stages to increase well performance while reducing cost. We plan to continue to use right-sized completion designs on wells we drill in 2020, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and evolving 3-D bit cutter technology to reduce time-on-location and total well cost. Our engineers have worked with service providers to optimize fluid systems and bit designs to increase drill rate and hole cleaning resulting in higher capital efficiency in the drilling program. As of December 31, 2019, we had four rigs active in the Williston Basin.

Central Rocky Mountains

Our Central Rocky Mountains operations include properties at our Redtail field in the Denver-Julesburg Basin ("DJ Basin") in Weld County, Colorado targeting the Niobrara and Codell/Fort Hays formations and encompassing approximately 96,400 gross (84,600 net) developed and undeveloped acres as of December 31, 2019. Our estimated proved reserves in the Central Rocky Mountains as of December 31, 2019 were 23.1 MMBOE (61% oil), which represented 5% of our total estimated proved reserves and contributed 10.4 MBOE/d of average daily production in the fourth quarter of 2019.

We have established production in the Niobrara "A", "B" and "C" zones and the Codell/Fort Hays formations. We completed 22 drilled uncompleted wells ("DUCs") in our Redtail field during the first half of 2018, and no additional wells were drilled or completed in 2019. During 2019 we worked on maintaining base production in this area with improved artificial lift techniques and reductions in lease operating expenses.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of December 31, 2019, the plant was processing 22 MMcf/d.

Other

Our other operations primarily relate to non-core assets in Colorado, Mississippi, North Dakota, Texas and Wyoming. As of December 31, 2019, these properties contributed 8.8 MMBOE (83% oil) of proved reserves to our portfolio of operations, which represented 2% of our total estimated proved reserves and contributed 0.6 MBOE/d of average daily production in the fourth quarter of 2019.

Reserves

As of December 31, 2019 and 2018, all of our oil and gas reserves were attributable to properties within the United States. A summary of our proved oil and gas reserves as of December 31, 2019 and 2018 based on average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2019 and 2018, respectively) is as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
2019				
Proved developed reserves	190,725	72,102	576,213	358,863
Proved undeveloped reserves	77,528	21,739	163,829	126,572
Total proved reserves	268,253	93,841	740,042	485,435
2018				
Proved developed reserves	194,869	82,725	529,154	365,786
Proved undeveloped reserves	92,095	28,559	201,930	154,309
Total proved reserves	286,964	111,284	731,084	520,095

Proved reserves. Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Total extensions and discoveries of 34.0 MMBOE in 2019 were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased our proved reserves.

Sales of minerals in place totaled 4.9 MMBOE during 2019 and were primarily attributable to the disposition of certain non-operated properties in North Dakota as further described in "Acquisitions and Divestitures" within Item 1 of this Annual Report on Form 10-K.

In 2019, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 17.9 MMBOE. Included in this change were upward revisions of 48.0 MMBOE to proved undeveloped reserves primarily located in the Williston Basin in locations where we have significant development activity and past drilling success. Offsetting these upward reserve revisions were: (i) 32.9 MMBOE of downward adjustments caused by lower crude oil, NGL and natural gas prices incorporated into our reserve estimates at December 31, 2019 as compared to December 31, 2018, (ii) 19.3 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance across our Northern and Central Rockies assets and (iii) 13.7 MMBOE of proved undeveloped reserves no longer expected to be developed within five years from their initial recognition.

Proved undeveloped reserves. Our PUD reserves decreased 18% or 27.7 MMBOE on a net basis from December 31, 2018 to December 31, 2019. The following table provides a reconciliation of our PUDs for the year ended December 31, 2019:

	Total (MBOE)
PUD balance—December 31, 2018	154,309
Converted to proved developed through drilling	(42,801)
Added from extensions and discoveries	19,436
Sold	(2)
Revisions	(4,370)
PUD balance—December 31, 2019	126,572

During 2019, we incurred $475 million in capital expenditures, or $11.10 per BOE, to drill and bring on-line 42.8 MMBOE of PUD reserves. In addition, we added 19.4 MMBOE of PUDs from extensions and discoveries during the year primarily due to successful drilling in the Williston Basin. We have made an investment decision and adopted a development plan to drill all of our individual PUD locations within five years of the date such PUDs were added. In that regard, under our current 2020 development plan, we expect to convert approximately 48.1 MMBOE of PUDs to proved developed reserves during the year.

Preparation of reserves estimates. We maintain adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to our internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, transportation, gathering, compression and other expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firm Cawley, Gillespie & Associates, Inc. (“CG&A”) meets with our technical personnel in our Denver office to review field performance and future development plans. Following this review, the reserve database and supporting data is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to our reserve database is restricted to specific members of the reservoir engineering department.

CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. W. Todd Brooker, President. Mr. Brooker is a State of Texas Licensed Professional Engineer. Refer to Exhibit 99.2 of this Annual Report on Form 10-K for the Report of Cawley, Gillespie & Associates, Inc. and further information regarding the professional qualifications of Mr. Brooker.

Trina Medina, our Director of Reservoir Engineering, is responsible for overseeing the preparation of the reserves estimates. She has more than 25 years of broad reservoir engineering experience in the oil and gas industry, focused across conventional, unconventional and secondary recovery evaluation and development projects, including corporate reserves estimations. Ms. Medina holds a Bachelor of Science degree in petroleum engineering from the Universidad Central de Venezuela, a Master of Science degree in reservoir engineering from Texas A&M University and a Master of Science degree in reservoir geoscience from the Institut Francais du Petrole. Ms. Medina is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by core area at December 31, 2019. Net acreage represents our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests has been excluded.

	Developed Acreage		Undeveloped Acreage [1]		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Northern Rocky Mountains	698,891	435,029	57,905	41,302	756,796	476,331
Central Rocky Mountains	39,716	36,264	56,646	48,343	96,362	84,607
Other [2]	85,570	52,351	56,817	24,420	142,387	76,771
	824,177	523,644	171,368	114,065	995,545	637,709

(1) Out of a total of approximately 171,400 gross (114,100 net) undeveloped acres as of December 31, 2019, the portion of our net undeveloped acreage that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 18% in 2020, 13% in 2021 and 15% in 2022.

(2) Other includes Arkansas, Colorado, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah and Wyoming.

Production History

The following table presents historical information about our produced oil and gas volumes:

	Year Ended December 31,		
	2019	2018	2017
Total company production			
Oil (MMBbl)	29.8	31.5	29.3
NGL (MMBbl)	7.6	7.4	7.0
Natural gas (Bcf)	50.5	46.8	41.3
Total (MMBOE)	45.8	46.7	43.1
Daily average (MBOE/d)	125.5	128.0	118.1
Sanish field production [1]			
Oil (MMBbl)	5.8	6.2	5.7
NGL (MMBbl)	1.1	1.2	1.1
Natural gas (Bcf)	7.6	7.2	7.1
Total (MMBOE)	8.2	8.6	8.0
Average sales prices (before the effects of hedging)			
Oil (per Bbl)	$ 50.06	$ 58.70	$ 44.30
NGLs (per Bbl)	$ 6.76	$ 20.78	$ 16.00
Natural gas (per Mcf)	$ 0.57	$ 1.66	$ 1.78
Average production costs (per BOE)			
Lease operating expenses	$ 7.17	$ 6.68	$ 6.47
Transportation, gathering, compression and other	$ 0.93	$ 1.03	$ 2.10

(1) The Sanish field was our only field that contained 15% or more of our total proved reserve volumes during the periods presented.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by core area at December 31, 2019. A net well represents our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells[1]	
	Gross	Net	Gross	Net	Gross	Net
Northern Rocky Mountains	3,022	1,426	-	-	3,022	1,426
Central Rocky Mountains	392	312	-	-	392	312
Other [2]	1,541	396	66	37	1,607	433
Total	4,955	2,134	66	37	5,021	2,171

(1) 20 wells have multiple completions, and these 20 wells contain a total of 41 completions. One or more completions in the same bore hole are counted as one well.

(2) Other primarily includes non-core oil and gas properties located in Colorado, New Mexico, North Dakota, Texas and Wyoming.

Oil and Gas Drilling Activity

We are engaged in numerous drilling activities on properties presently owned, and we intend to drill or develop other properties acquired in the future. The following table sets forth our oil and gas drilling activity for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2019						
Development	208	2	210	93.9	0.1	94.0
Exploratory	-	-	-	-	-	-
Total	208	2	210	93.9	0.1	94.0
2018						
Development	210	-	210	120.9	-	120.9
Exploratory	1	-	1	0.8	-	0.8
Total	211	-	211	121.7	-	121.7
2017						
Development	238	-	238	164.1	-	164.1
Exploratory	-	-	-	-	-	-
Total	238	-	238	164.1	-	164.1

As of December 31, 2019, we had four operated drilling rigs active on our properties in our Northern Rocky Mountains area. As of December 31, 2019, we had 129 gross (57.1 net) operated and non-operated wells in the process of drilling, completing or waiting on completion.

Hydraulic Fracturing

Hydraulic fracturing is a common practice in the oil and gas industry that is used to stimulate production of hydrocarbons from tight oil and gas formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. This process has typically been regulated by state oil and gas commissions. However, as described in more detail in “Business – Regulation – Environmental Regulations – Hydraulic Fracturing” in Item 1 of this Annual Report on Form 10-K, the EPA has initiated the regulation of hydraulic fracturing, other federal agencies are examining hydraulic fracturing, and federal legislation is pending with respect to hydraulic fracturing. We have utilized hydraulic fracturing in the completion of our wells in our most active areas located in the states of North Dakota, Montana and Colorado and we plan to continue to utilize this completion methodology.

Substantially all of our 126.6 MMBOE of proved undeveloped reserves are associated with hydraulic fracture treatments.

We are not aware of any environmental incidents, citations or suits that have occurred during the last three years related to hydraulic fracturing operations involving oil and gas properties that we operate or in which we own a non-operated interest.

In order to minimize any potential environmental impact from hydraulic fracture treatments, we have taken the following steps:

- we follow fracturing and flowback procedures that comply with or exceed North Dakota Industrial Commission or other state requirements;
- we train all company and contract personnel who are responsible for well preparation, fracture stimulation and flowback on our procedures;
- we have implemented the incremental procedures of running a well casing caliper, visually inspecting the surface joint of intermediate casing and, if a lighter wall joint of casing or drilling wear is detected, reducing the minimum burst pressure accordingly;
- for wells that are within one mile of major bodies of water or locations that lead to bodies of water, we construct berming around the well location prior to initiating fracturing operations;
- we run fracturing strings in certain situations when extra precaution is warranted, such as where the anticipated maximum treating pressure for the well is greater than the pressure rating of the intermediate casing or in areas located within one mile of major bodies of water;
- we conduct annual emergency incident response drills in our active areas; and
- we are a member of the Sakakawea Area Spill Response LLC (“SASR”), which is comprised of 17 oil and gas related companies operating in the Missouri River and Lake Sakakawea regions of North Dakota. Members agreed to share spill response resources and maintain SASR-owned water response equipment that can be accessed quickly in the early stages of a spill.

While we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations, we do have general liability and excess liability insurance policies that we believe would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry, generally provide for sales based on prevailing market prices in the area, and generally have terms of one year or less.

As of December 31, 2019, we have entered into three physical delivery contracts which require us to deliver fixed volumes of crude oil. One of these contracts is tied to crude oil production from the Williston Basin and requires delivery of 10 MBbl/d for a term of seven years. The effective date of this contract is contingent upon the completion of certain related pipelines, which are currently expected to be brought online in 2021. Under the terms of this contract, if we fail to deliver the committed volumes we will be required to pay a deficiency payment of $5.75 per undelivered Bbl, subject to upward adjustment, over the duration of the contract. However, we believe that our production and reserves are sufficient to fulfill the delivery commitment in the Williston Basin, and we therefore expect to avoid any payments for deficiencies under this contract.

Our two remaining physical delivery contracts are effective as of December 31, 2019. One of these contracts is tied to oil production at our Sanish field in Mountrail County, North Dakota and is effective for a term of seven years ending May 31, 2024. The other contract is tied to oil production at our Redtail field in Weld County, Colorado and terminates in April 2020. The following table summarizes our Sanish and Redtail delivery commitments as of December 31, 2019:

Period	Sanish Contracted Crude Oil Volumes (Bbl)	Redtail Contracted Crude Oil Volumes (Bbl)	As a Percentage of Total 2019 Oil Production
Jan - Dec 2020	5,490,000	4,140,000	32%
Jan - Dec 2021	5,475,000	—	18%
Jan - Dec 2022	5,475,000	—	18%
Jan - Dec 2023	5,475,000	—	18%
Jan - Dec 2024	2,280,000	—	8%

Under the terms of the Sanish contract, if we fail to deliver the committed volumes we will be required to pay a deficiency payment of $7.00 per undelivered Bbl, subject to upward adjustment, over the duration of the contract. However, we believe that our production and reserves are sufficient to fulfill the delivery commitment at our Sanish field, and we therefore expect to avoid any payments for deficiencies under this contract.

Under the terms of the Redtail contract, if we fail to deliver the committed volumes we are required to pay a deficiency payment that currently totals $5.24 per undelivered Bbl over the remaining term of the contract. We have determined that it is not probable that future oil production from our Redtail field will be sufficient to meet the minimum volume requirements specified in the related physical delivery contract, and as a result, we expect to make deficiency payments for any shortfalls in delivering the minimum committed volumes. We recognize any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred. During 2019, 2018 and 2017, total deficiency payments under this contract, as well as a second Redtail contract that we terminated in February 2018, amounted to $64 million, $39 million and $66 million, respectively.

Item 3. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is management's opinion that the loss for any litigation matters and claims we are involved in that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on our consolidated financial position, cash flows or results of operations.

We are involved in litigation related to a payment arrangement with a third party which currently claims damages up to $41 million, as well as court costs and interest, that is scheduled to go to trial in May 2020. Certain amounts have been accrued in accrued liabilities and other in the consolidated balance sheet as of December 31, 2019 and general and administrative expenses in the consolidated statement of operations for the year ended December 31, 2019 based on the determination that it is probable that a loss has been incurred and can be reasonably estimated.

Item 4. Mine Safety Disclosures

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following table sets forth certain information, as of February 20, 2020, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
Bradley J. Holly	49	Chairman, President and Chief Executive Officer
Bruce R. DeBoer	67	Chief Administrative Officer, General Counsel and Secretary
Correne S. Loeffler	43	Chief Financial Officer
Charles J. Rimer	62	Chief Operating Officer
Timothy M. Sulser	43	Chief Strategy Officer
Sirikka R. Lohoefener	41	Vice President and Controller

The following biographies describe the business experience of our executive officers:

Bradley J. Holly joined us in November 2017 upon his appointment as director and election as President and Chief Executive Officer. Mr. Holly was appointed Chairman of the Board in May 2018. Mr. Holly has 25 years of experience in the oil and gas industry. Prior to joining Whiting, he held various management and technical positions during his 20 years at Anadarko Petroleum Corporation including Executive Vice President, U.S. Onshore Exploration and Production; Senior Vice President, U.S. Onshore Exploration and Production; Senior Vice President, Operations; Vice President, Operations for the Southern and Appalachia Region; among others. He began his career in 1994 with Amoco Corporation. Mr. Holly holds a Bachelor of Science degree in petroleum engineering from Texas Tech University, and he is a graduate of the Harvard Business School's Advanced Management Program.

Bruce R. DeBoer joined us as Vice President, General Counsel and Secretary in January 2005 and was elected Chief Administrative Officer, General Counsel and Secretary effective August 2019. Previously, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has 40 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science degree in political science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

Correne S. Loeffler joined us in August 2019 as Chief Financial Officer. Ms. Loeffler has 14 years of oil and gas experience. She previously served as Vice President, Finance and Treasurer for Callon Petroleum Company for two years and also served as Interim Chief Financial Officer for a portion of that time. Prior to joining Callon, Ms. Loeffler was Executive Director with JPMorgan Securities, LLC where she was employed in the Corporate Client Bank Group for 12 years. She started her career as a consultant at Accenture. Ms. Loeffler holds a Bachelor of Arts degree from Indiana University and a Master of Business Administration degree from the University of Texas.

Charles J. Rimer joined us in November 2018 as Chief Operating Officer. Mr. Rimer has 37 years of experience in the industry. Prior to joining Whiting, he held various management and technical positions during his 16 years at Noble Energy, Inc. including Senior Vice President, Global Services; Senior Vice President, U.S. Onshore; Senior Vice President, Global EHSR and Operations Services; Vice President of Operations Services; among others. He also held various management and technical positions at Aspect Resources, Vastar Resources and ARCO Oil & Gas Company where he began his career in 1983. Mr. Rimer holds a Bachelor of Arts degree in business from Furman University and Bachelor of Science degree in petroleum engineering from the University of Texas.

Timothy M. Sulser joined us in September 2018 as Chief Corporate Development and Strategy Officer. Mr. Sulser has 21 years of oil and gas experience. He co-founded Salt Creek Oil and Gas, LLC in 2015 after five years as an investment banker with Tudor, Pickering, Holt & Co. ("TPH"), most recently heading its Denver office. While at TPH, Mr. Sulser advised upstream clients on acquisitions and divestitures and energy capital markets. Prior to joining TPH, he worked as a reservoir engineer for reserve engineering consultant Netherland, Sewell, and Associates in Houston, Texas. He started his career with Marathon Oil Company in Lafayette, Louisiana. Mr. Sulser holds a Bachelor of Science degree in petroleum engineering from Montana Tech and a Master of Science degree in operations research from Columbia University.

Sirikka R. Lohoefener joined us in June 2006 as a Senior Financial Accountant, became Financial Reporting Manager in January 2011 and Controller in March 2015. She was appointed Controller and Treasurer in March 2017, Vice President, Controller and Treasurer in December 2018 and Vice President and Controller in October 2019 and serves as the Company's designated principal accounting officer. Prior to joining Whiting, Ms. Lohoefener spent five years with Wagner, Burke & Barnes, LLP, a public accounting firm previously

based in Golden, Colorado. She holds a Master of Accountancy degree from the University of Missouri and is a Certified Public Accountant.

Executive officers are elected by, and serve at the discretion of, the Board of Directors. There are no family relationships between any of our directors or executive officers.

PART II

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

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL". On February 20, 2020, there were 444 holders of record of our common stock.

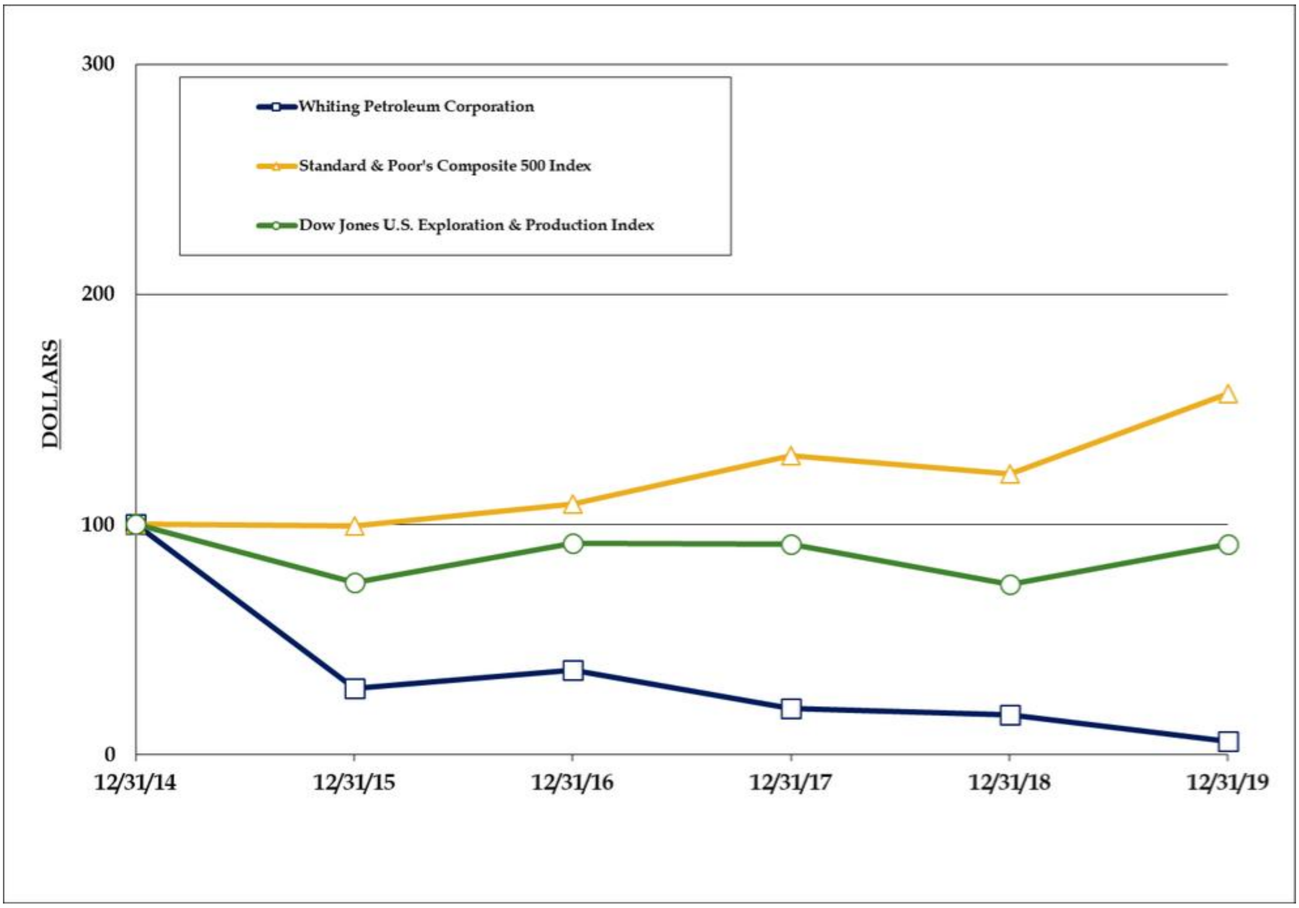
On November 8, 2017, our Board of Directors approved a reverse stock split of our common stock at a ratio of one-for-four and a reduction in the number of authorized shares of our common stock from 600,000,000 shares to 225,000,000. Our common stock began trading on a split-adjusted basis on November 9, 2017 upon opening of the markets. All share and per share amounts in this Annual Report on Form 10-K for periods prior to November 2017 have been retroactively adjusted to reflect the reverse stock split.

We have not paid any cash dividends on our common stock since we were incorporated in July 2003, and we do not anticipate paying any such dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since December 31, 2014 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones U.S. Exploration & Production Index. Such changes have been measured by dividing (a) the sum of (i) the cumulative amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2014 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones U.S. Exploration & Production Index, respectively.



	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019
Whiting Petroleum Corporation	$ 100	$ 29	$ 36	$ 20	$ 17	$ 6
Standard & Poor's Composite 500 Index	100	99	109	130	122	157
Dow Jones U.S. Exploration & Production Index	100	75	92	91	74	91

Item 6. Selected Financial Data

The consolidated statements of operations and statements of cash flows information for the years ended December 31, 2019, 2018 and 2017 and the consolidated balance sheet information at December 31, 2019 and 2018 are derived from our audited financial statements included elsewhere in this report. The consolidated statements of operations and statements of cash flows information for the years ended December 31, 2016 and 2015 and the consolidated balance sheet information at December 31, 2017, 2016 and 2015 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent proved property acquisition of properties in North Dakota and Montana on July 31, 2018. In addition, our historical results also include the effects of our recent property divestitures beginning on the following closing dates: non-operated properties in North Dakota, July 29, 2019 and August 15, 2019; properties in the Fort Berthold Indian Reservation area, September 1, 2017; gas processing plants and related gathering systems in North Dakota, January 1, 2017; properties in the North Ward Estes field, July 27, 2016; water facilities in Colorado, December 16, 2015; non-core properties in various fields across multiple states, December 15, 2015, November 12, 2015 and June 10, 2015; and the underlying properties of Whiting USA Trust I, April 15, 2015. For a discussion of other material factors affecting the comparability of the information presented below, refer to "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this Annual Report on Form 10-K.

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(in millions, except per share data)				
Consolidated Statements of Operations Information					
Operating revenues	$ 1,572.2	$ 2,081.4	$ 1,481.4	$ 1,285.0	$ 2,092.5
Net income (loss) attributable to common shareholders	$ (241.2)	$ 342.5	$ (1,237.6)	$ (1,339.1)	$ (2,219.2)
Earnings (loss) per common share, basic [1]	$ (2.64)	$ 3.77	$ (13.65)	$ (21.27)	$ (45.41)
Earnings (loss) per common share, diluted [1]	$ (2.64)	$ 3.73	$ (13.65)	$ (21.27)	$ (45.41)
Other Financial Information					
Net cash provided by operating activities	$ 756.0	$ 1,092.0	$ 577.1	$ 595.0	$ 1,051.4
Net cash provided by (used in) investing activities	$ (733.8)	$ (953.1)	$ 73.4	$ (222.6)	$ (1,982.1)
Net cash provided by (used in) financing activities	$ (27.1)	$ (1,004.7)	$ 155.6	$ (315.3)	$ 868.7
Cash capital expenditures	$ 793.4	$ 956.7	$ 852.0	$ 543.9	$ 2,483.7
Consolidated Balance Sheet Information					
Total assets	$ 7,636.7	$ 7,759.6	$ 8,403.0	$ 9,876.1	$ 11,389.1
Long-term debt	$ 2,799.9	$ 2,792.3	$ 2,764.7	$ 3,535.3	$ 5,197.7
Total equity [2]	$ 4,025.0	$ 4,270.3	$ 3,919.1	$ 5,149.2	$ 4,758.6

(1) On November 8, 2017, our Board of Directors approved a one-for-four reverse stock split of our common stock. Earnings (loss) per common share for periods prior to 2017 have been retroactively adjusted to reflect the reverse stock split.

(2) No cash dividends were declared or paid on our common stock during the periods presented.

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

Unless the context otherwise requires, the terms "Whiting", "we", "us", "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties and exploring other basins where we can apply our existing knowledge and expertise to build production and add proved reserves. As a result of lower crude oil prices during 2017 and 2018, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2019, we focused on developing our large resource play in the Williston Basin of North Dakota and Montana, while continuing to closely align our capital spending with cash flows generated from operations. We continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under "Acquisition and Divestiture Highlights" and in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, competition from other sources of energy, and the other items discussed under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10-K. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2018:

	2018				2019			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude oil	$ 62.89	$ 67.90	$ 69.50	$ 58.83	$ 54.90	$ 59.83	$ 56.45	$ 56.96
Natural gas	$ 3.13	$ 2.77	$ 2.88	$ 3.62	$ 3.00	$ 2.58	$ 2.29	$ 2.44

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserve quantities. Substantial and extended declines in oil, NGL and natural gas prices have resulted, and may result, in impairments of our proved oil and gas properties or undeveloped acreage (such as the impairments discussed below under "Results of Operations") and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders, as occurred with our most recent semi-annual redetermination where the borrowing base was lowered from $2.25 billion to $2.05 billion in October 2019. Upon a redetermination, if total outstanding credit exposure exceeds the redetermined borrowing base, we will be required to prepay outstanding borrowings in an aggregate principal amount equal to such excess in six substantially equal monthly installments. Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives.

For a discussion of material changes to our proved reserves from December 31, 2018 to December 31, 2019 and our ability to convert PUDs to proved developed reserves, refer to "Reserves" in Item 2 of this Annual Report on Form 10-K. Additionally, for a discussion relating to the minimum remaining terms of our leases, refer to "Acreage" in Item 2 of this Annual Report on Form 10-K.

2019 Highlights and Future Considerations

Operational Highlights

Northern Rocky Mountains – Williston Basin

Our properties in the Williston Basin of North Dakota and Montana target the Bakken and Three Forks formations. Net production from the Williston Basin averaged 112.0 MBOE/d for the fourth quarter of 2019, representing a 1% increase from 111.4 MBOE/d in the third quarter of 2019. Across our acreage in the Williston Basin, we have implemented customized, right-sized completion designs which utilize the optimum volume of proppant, fluids, and frac stages to increase well performance while reducing cost. We have increased stages pumped per day by focusing on new technologies such as quick-install wellhead connections and frac plug innovations. We plan to continue to use right-sized completion designs on wells we drill in 2020, while also utilizing state-of-the-art drilling rigs, high-torque mud motors and 3-D bit cutter technology to reduce time-on-location and total well cost. As of December 31, 2019, we had four rigs active in the Williston Basin. We drilled 31 wells and put 35 wells on production in this area during the fourth quarter of 2019. First quarter 2020 production has been impacted by severe weather conditions and associated electric submersible pump failures on multiple high value wells. We estimate that this will impact first quarter 2020 production results by approximately 5 MBOE/d.

Central Rocky Mountains – Denver-Julesburg Basin

Our Redtail field in the Denver-Julesburg Basin (“DJ Basin”) in Weld County, Colorado targets the Niobrara and Codell/Fort Hays formations. Net production from the Redtail field averaged 10.4 MBOE/d in the fourth quarter of 2019, representing a 7% decrease from 11.2 MBOE/d in the third quarter of 2019. We have established production in the Niobrara “A”, “B” and “C” zones and the Codell/Fort Hays formations. We completed 22 drilled uncompleted wells (“DUCs”) in our Redtail field during the first half of 2018, and no additional wells were drilled or completed in 2019. During 2019 we worked on maintaining base production with improved artificial lift techniques and reductions in lease operating expenses.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of December 31, 2019, the plant was processing 22 MMcf/d.

Financing Highlights

In September 2019, we paid $299 million to complete a cash tender offer for $300 million aggregate principal amount of our 2020 Convertible Senior Notes, which payment consisted of the 99.0% purchase price plus all accrued and unpaid interest on the notes.

In September 2019, we paid $24 million to repurchase $25 million aggregate principal amount of our 2021 Senior Notes, which payment consisted of the average 94.708% purchase price plus all accrued and unpaid interest on the notes. In October 2019, we paid an additional $72 million to repurchase $75 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 95.467% purchase price plus all accrued and unpaid interest on the notes.

We financed the tender offer and repurchases with borrowings under our credit agreement. Refer to the “Long Term Debt” footnote in the notes to the consolidated financial statements for more information on the tender offer and repurchases.

In October 2019, the borrowing base under our credit agreement was reduced from $2.25 billion to $2.05 billion in connection with the November 1, 2019 regular borrowing base redetermination, with no change to the aggregate commitments of $1.75 billion.

2020 Exploration and Development Budget

Our 2020 exploration and development (“E&D”) budget is a range of $585 million to $620 million, which we expect to fund substantially with net cash provided by our operating activities and cash on hand, and represents a decrease from the $778 million incurred on E&D expenditures during 2019. This reduced spending is primarily attributable to our commitment to closely align capital spending with cash flows generated from operations. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would generate more or less free cash flow than we currently anticipate, and may adjust our E&D budget and attempt to enter into agreements with industry partners, divest certain oil and gas property interests, adjust borrowings outstanding under our credit facility or access the capital markets as necessary. Approximately 90% of the midpoint of our 2020 E&D budget currently is allocated to drilling and completion activity. Of our existing development opportunities, we believe this allocation of our capital presents the opportunity for the highest return and most efficient use of our capital.

Acquisition and Divestiture Highlights

On July 29, 2019, we completed the divestiture of our interests in 137 non-operated, producing oil and gas wells located in McKenzie, Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $27 million (before closing adjustments).

On August 15, 2019, we completed the divestiture of our interests in 58 non-operated, producing oil and gas wells located in Richland County, Montana and Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $26 million (before closing adjustments).

On a combined basis, the divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2018 and our April 2019 average daily production.

On January 9, 2020, we completed the divestiture of our interests in 30 non-operated, producing oil and gas wells and related undeveloped acreage located in McKenzie County, North Dakota for aggregate sales proceeds of $25 million (before closing adjustments). The divested properties consisted of less than 1% of our estimated proved reserves as of December 31, 2019 and 1% of our average daily production for the year ended December 31, 2019.

Restructuring

On July 31, 2019, we executed a workforce reduction as part of an organizational redesign and cost reduction strategy to better align our business with the current operating environment and drive long-term value. We incurred a one-time net charge of $8 million to general and administrative expense during 2019 related to this restructuring.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Year Ended December 31,		
	2019	2018	2017
Net production			
Oil (MMBbl)	29.8	31.5	29.3
NGLs (MMBbl)	7.6	7.4	7.0
Natural gas (Bcf)	50.5	46.8	41.3
Total production (MMBOE)	45.8	46.7	43.1
Net sales (in millions)			
Oil [(1)]	$ 1,492.2	$ 1,850.1	$ 1,296.4
NGLs	51.4	153.6	111.6
Natural gas	28.6	77.7	73.4
Total oil, NGL and natural gas sales	$ 1,572.2	$ 2,081.4	$ 1,481.4
Average sales prices			
Oil (per Bbl) [(1)]	$ 50.06	$ 58.70	$ 44.30
Effect of oil hedges on average price (per Bbl)	0.83	(4.98)	0.29
Oil after the effect of hedging (per Bbl)	$ 50.89	$ 53.72	$ 44.59
Weighted average NYMEX price (per Bbl) [(2)]	$ 56.97	$ 64.69	$ 51.11
NGLs (per Bbl)	$ 6.76	$ 20.78	$ 16.00
Natural gas (per Mcf)	$ 0.57	$ 1.66	$ 1.78
Weighted average NYMEX price (per MMBtu) [(2)]	$ 2.58	$ 3.11	$ 2.97
Costs and expenses (per BOE)			
Lease operating expenses	$ 7.17	$ 6.68	$ 6.47
Transportation, gathering, compression and other	$ 0.93	$ 1.03	$ 2.10
Production and ad valorem taxes	$ 3.02	$ 3.68	$ 2.80
Depreciation, depletion and amortization	$ 17.82	$ 16.73	$ 22.01
General and administrative	$ 2.89	$ 2.64	$ 2.88

(1) Before consideration of hedging transactions.

(2) Average NYMEX pricing weighted for monthly production volumes.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue decreased $509 million to $1.6 billion when comparing 2019 to 2018. Changes in sales revenue between periods are due to changes in production sold and changes in average commodity prices realized (excluding the impacts of hedging). For 2019, decreases in total production accounted for approximately $90 million of the change in revenue and decreases in commodity prices realized accounted for approximately $419 million of the change in revenue when comparing to 2018.

Our oil volumes decreased 5% and our NGL and natural gas sales volumes increased 3% and 8%, respectively, during 2019 compared to 2018. The oil volume decrease was mainly attributable to normal field production decline primarily in the DJ Basin, where we ceased our development activity during 2019, as well as the result of infrastructure constraints in the Williston Basin and the impact of severe weather experienced in both the Williston Basin and the DJ Basin during 2019. This decrease was partially offset by increased production from new wells drilled and completed in the Williston Basin. The NGL and natural gas volume increases between periods generally relate to new wells drilled and completed in the Williston Basin over the last twelve months, as well as additional volumes processed as more wells were connected to gas processing plants in the Williston Basin in an effort to increase our overall gas capture rate in this area and reduce flared volumes. Many of the new Williston Basin wells are in areas with higher gas-to-oil production ratios than previously drilled areas. These NGL and natural gas volume increases were partially offset by normal field production decline across several of our areas.

Our average price for oil (before the effects of hedging), NGLs and natural gas decreased 15%, 67% and 66%, respectively, between periods. Our average sales price realized for oil is impacted by deficiency payments we were making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During 2019 and 2018, our total average sales price realized for oil was $2.14 per Bbl lower and $1.25 per Bbl lower, respectively, as a result of these deficiency payments. On February 1, 2018, we paid $61 million to the counterparty to one of these Redtail delivery contracts to settle all future minimum volume commitments under the agreement. The remaining agreement will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contract terminates. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements for more information on these physical delivery contracts and the related deficiency payments. Our average sales price realized for natural gas is impacted by rising market differentials as compared to NYMEX as well as high fixed third-party costs for transportation, gathering and compression services.

Lease Operating Expenses. Our lease operating expenses ("LOE") during 2019 were $328 million, a $17 million increase over 2018. This increase was primarily due to new wells put on production in the Williston Basin during 2019 as well as rising costs of oilfield goods and services. These increases were partially offset by cost savings as a result of our company restructuring in July 2019 and cost reduction initiatives implemented during 2019. Refer to "Restructuring" for more information on this event.

Our lease operating expenses on a BOE basis also increased when comparing 2019 to 2018. LOE per BOE amounted to $7.17 during 2019, which represents an increase of $0.49 per BOE (or 7%) from 2018. This increase was mainly due to the overall increase in LOE expense discussed above, as well as lower overall production volumes between periods.

Transportation, Gathering, Compression and Other. Our transportation, gathering, compression and other expenses ("TGC") during 2019 were $42 million, a $6 million decrease over 2018. This decrease was primarily due to lower realized NGL prices during 2019, which led to lower gas processing fees under our percentage-of-proceeds contracts as compared to 2018.

TGC on a BOE basis also decreased when comparing 2019 to 2018. TGC per BOE amounted to $0.93 during 2019, which represents a decrease of $0.10 per BOE (or 10%) from 2018. This decrease was mainly due to the overall decrease in TGC expense discussed above, partially offset by lower overall production volumes between periods.

Production and Ad Valorem Taxes. Our production and ad valorem taxes during 2019 were $138 million, a $34 million decrease compared to 2018, which was primarily due to lower sales revenue between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.6% and 7.8% for 2019 and 2018, respectively. Our production tax rate for 2019 was higher than the rate for 2018 primarily due to our concentration of development over the last twelve months in the Williston Basin states of North Dakota and Montana, which have higher tax rates than Colorado where we have had limited development activity over the past twelve months. This increase in rate was partially offset by certain North Dakota wells receiving stripper well status, which reduces the rate from 10% to 5%.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $35 million in 2019 as compared to 2018. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2019	**2018**
Depletion	$ 799,080	$ 763,429
Accretion of asset retirement obligations	11,602	11,405
Depreciation	5,806	6,495
Total	$ 816,488	$ 781,329

DD&A increased between periods primarily due to $36 million in higher depletion expense, consisting of a $52 million increase related to a higher depletion rate between periods, partially offset by a $16 million decrease due to lower overall production volumes during 2019. On a BOE basis, our overall DD&A rate of $17.82 for 2019 was 7% higher than the rate of $16.73 in 2018. The primary factors contributing to this higher DD&A rate were a recent shift in our development activity to areas with higher average historical DD&A rates and downward revisions to proved reserves over the last twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $13 million in 2019 as compared to 2018. The components of our exploration and impairment expense were as follows (in thousands):

	Year Ended December 31,	
	2019	**2018**
Exploration	$ 36,872	$ 22,080
Impairment	17,866	45,288
Total	$ 54,738	$ 67,368

Exploration costs increased $15 million between periods primarily due to increased deficiency fees paid under our produced water disposal agreement driven by reduced drilling and completions at our Redtail field during 2019 compared to 2018.

Impairment expense in 2019 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. Impairment expense in 2018 primarily related to (i) $29 million of leasehold amortization costs associated with individually insignificant unproved properties and (ii) $8 million in impairment write-downs of undeveloped acreage costs for leases where we have no future plans to drill.

General and Administrative Expenses. We report general and administrative ("G&A") expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Year Ended December 31,	
	2019	**2018**
General and administrative expenses	$ 224,885	$ 220,100
Reimbursements and allocations	(92,276)	(96,850)
General and administrative expenses, net	$ 132,609	$ 123,250

G&A expense before reimbursements and allocations increased $5 million during 2019 as compared to 2018 primarily due to an $8 million one-time net charge related to the company restructuring during 2019 as well as higher legal and litigation costs. In addition, G&A expense for 2018 includes $5 million of credits to bad debt expense related to the collection of certain receivables that had been previously deemed uncollectible. These factors resulting in increased G&A expense for 2019 were partially offset by lower employee compensation costs as a result of the restructuring. The decrease in reimbursements and allocations in 2019 was primarily the result of lower headcount due to the restructuring as well as lower development activity during the fourth quarter of 2019. Refer to "Restructuring" for more information on the company restructuring.

Our G&A expenses on a BOE basis also increased between periods. G&A expense per BOE amounted to $2.89 in 2019, which represents an increase of $0.25 per BOE (9%) from 2018. This increase was mainly due to the overall increase in G&A expense discussed above, as well as lower overall production volumes between periods.

Derivative Loss, Net. Our commodity derivative contracts are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative loss, net amounted to $54 million and $17 million for 2019 and 2018, respectively. These losses primarily related to our collar, swap and option commodity derivative contracts and resulted from the upward shift in the futures curve of forecasted commodity prices for crude oil during the respective periods.

For further information on our outstanding derivatives refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Year Ended December 31,	
	2019	2018
Notes	$ 146,583	$ 152,366
Amortization of debt issue costs, discounts and premiums	28,340	30,700
Credit agreement	15,236	13,262
Other	888	1,146
Total	$ 191,047	$ 197,474

The decrease in interest expense of $6 million between periods was mainly attributable to lower interest incurred on our notes in 2019 compared to 2018 resulting from the redemption of the 2019 Notes in January 2018, the tender offer for the 2020 Convertible Senior Notes in September 2019 and the repurchases of the 2021 Senior Notes in September and October 2019. Refer to the "Long-Term Debt" footnote in the notes to the consolidated financial statements for more information on these debt transactions.

Our weighted average debt outstanding during 2019 was $2.9 billion versus $3.0 billion for 2018. Our weighted average effective cash interest rate was 5.5% during both 2019 and 2018.

Gain (Loss) on Extinguishment of Debt. During 2019, we recognized a gain on extinguishment of debt of $8 million. In September 2019, we paid $299 million to purchase $300 million aggregate principal amount of the 2020 Convertible Senior Notes in a cash tender offer and recognized a $4 million gain on extinguishment of debt. Additionally, in September and October 2019, we paid $96 million to repurchase $100 million aggregate principal amount of the 2021 Senior Notes and recognized a $4 million gain on extinguishment of debt. During 2018, we redeemed all of the remaining $961 million aggregate principal amount of 2019 Senior Notes and recognized a $31 million loss on extinguishment of debt. Refer to the "Long-Term Debt" footnote in the notes to the consolidated financial statements for more information on these debt transactions.

Income Tax Expense (Benefit). Income tax expense for 2019 totaled $72 million as compared to $1 million for 2018. As a result of our positive pre-tax income in 2018, we transitioned from a net deferred tax asset position to a net deferred tax liability position as of December 31, 2018. Accordingly, we released the valuation allowance related to our general net deferred tax assets that was established in 2017 and recognized $1 million in deferred tax expense related to U.S. income tax for the year ended December 31, 2018. As a result of pre-tax losses in 2019, we transitioned from a net deferred tax liability position to a net deferred tax asset position for U.S. income taxes which resulted in the recognition of a full valuation allowance on our deferred tax assets again during the second quarter of 2019 and recognition of a $1 million deferred U.S. tax benefit. Additionally, during the fourth quarter of 2019, we recognized $74 million of Canadian deferred tax expense associated with the outside basis difference in Whiting Canadian Holding Company ULC pursuant to ASC 740-30-25-17. Refer to the "Income Taxes" footnote in the notes to the consolidated financial statements for more information on this deferred tax liability.

Our effective tax rates for 2019 and 2018 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes, permanent taxable differences and changes in the valuation allowance. Our overall effective tax rate decreased from 0.4% for 2018 to (42.7)% for 2019 primarily due to the recognition of the outside basis difference in Whiting Canadian Holding Company ULC.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

For discussion on the year ended December 31, 2018 compared to the year ended December 31, 2017, refer to Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2018 Annual Report on Form 10-K filed with the SEC on February 28, 2019 under the subheading "Year Ended December 31, 2018 Compared to Year Ended December 31, 2017."

Liquidity and Capital Resources

Overview. At December 31, 2019, we had $9 million of cash on hand and $4.0 billion of equity, while at December 31, 2018, we had $14 million of cash on hand and $4.3 billion of equity.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 65% and 67% of our total production in 2019 and 2018,

respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of February 20, 2020, we had contracts covering the sale of 31 MMBbl of oil per day for the remainder of 2020 and 6 MMBbl of oil per day for all of 2021. For further information on our outstanding derivatives refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements.

Cash Flows from 2019 Compared to 2018. During 2019, we generated $756 million of cash provided by operating activities, a decrease of $336 million from 2018. Cash provided by operating activities decreased primarily due to lower realized sales prices for oil, NGLs and natural gas, lower crude oil production volumes, as well as higher lease operating expenses, exploration costs and cash G&A expenses. These negative factors were partially offset by higher NGL and natural gas production volumes, a decrease in cash settlements paid on our derivative contracts, and lower production and ad valorem taxes, cash interest expense and TGC for 2019 compared to 2018. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses during 2019.

During 2019, cash flows from operating activities, $375 million of net borrowings under our credit agreement, proceeds from the sale of properties and cash on hand were used to finance $793 million of drilling and development expenditures, the repurchase of $300 million aggregate principal amount of 2020 Convertible Senior Notes and $100 million aggregate principal amount of 2021 Senior Notes, and $6 million of other property and equipment purchases.

Cash Flows from 2018 Compared to 2017. For discussion on cash flows for the year ended December 31, 2018 compared to the year ended December 31, 2017, refer to Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2018 Annual Report on Form 10-K filed with the SEC on February 28, 2019 under the subheading "Cash Flows from 2018 Compared to 2017."

Exploration and Development Expenditures. The following table details our E&D expenditures incurred by core area (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Northern Rocky Mountains	$ 768,651	$ 741,378	$ 601,737
Central Rocky Mountains	209	82,660	292,826
Other (1)	9,394	7,985	17,866
Total incurred	$ 778,254	$ 832,023	$ 912,429

(1) Other primarily includes non-core oil and gas properties located in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming.

We continually evaluate our capital needs and compare them to our capital resources. Our 2020 E&D budget is a range of $585 million to $620 million, which we expect to fund substantially with net cash provided by operating activities and cash on hand, and represents a decrease from the $778 million incurred on E&D expenditures during 2019. We believe that should additional attractive acquisition opportunities arise, we will attempt to finance additional capital expenditures through agreements with industry partners, divestitures of certain oil and gas property interests, borrowings under our credit agreement or by accessing the capital markets. Our level of E&D expenditures is largely discretionary, and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plan over the next twelve months and for the foreseeable future. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels (including availability under our credit agreement), access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Credit Agreement. Whiting Oil and Gas, our wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2019 had a borrowing base and aggregate commitments of $2.05 billion and $1.75 billion, respectively. As of December 31, 2019, we had $1.4 billion of available borrowing capacity under the credit agreement, which was net of $375 million of borrowings outstanding and $2 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year,

as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of our borrowing base, either on a periodic or special redetermination date, if total outstanding credit exposure exceeds the redetermined borrowing base, we will be required to prepay outstanding borrowings in an aggregate principal amount equal to such excess in six substantially equal monthly installments. In October 2019, the borrowing base under our credit agreement was reduced from $2.25 billion to $2.05 billion in connection with the November 1, 2019 regular borrowing base redetermination, with no change to the aggregate commitments of $1.75 billion.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of December 31, 2019, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. Interest under the credit agreement accrues at our option at either (i) a base rate for a base rate loan plus a margin between 0.50% and 1.50% based on the ratio of outstanding borrowings to the borrowing base, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus a margin of 1.50% and 2.50% based on the ratio of outstanding borrowings to the borrowing base. Additionally, we also incur commitment fees of 0.375% or 0.50% based on the ratio of outstanding borrowings to the borrowing base on the unused portion of the aggregate commitments of the lenders under the credit agreement.

The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 2020 Convertible Senior Notes) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. On September 13, 2019, we amended the credit agreement to, among other things, permit the repurchase, redemption, prepayment or other acquisition or retirement for value of any senior notes (as defined in the credit agreement) if (i) such transaction is for a price not greater than an amount equal to par plus accrued and unpaid interest and fees and any applicable make-whole premium, (ii) immediately after giving effect to such transaction, there is unused availability under the facility of not less than the greater of $100 million or 15% of the then effective total commitments, and (iii) our ratio of consolidated total debt as of the date of such transaction (upon giving effect thereto) to EBITDAX (as defined in the credit agreement) during the last four quarters is not greater than 3.25 to 1.0. Our business plan includes the intent to refinance certain senior notes, including our convertible senior notes due in 2020 and our senior notes due in 2021, as permitted by the September 13, 2019 amendment to the credit agreement. Consequently, we have classified the credit agreement as long-term debt.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of our restricted subsidiaries (as defined in the credit agreement). As of December 31, 2019, there were no retained earnings free from restrictions.

The credit agreement requires us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to the last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. As of December 31, 2019, we were in compliance with the covenants under the credit agreement. While not required to maintain compliance with covenants, our business plan may include property divestitures and utilizing our credit facility or accessing capital markets to repay outstanding debt.

For further information on the loan security related to our credit agreement, refer to the "Long-Term Debt" footnote in the notes to the consolidated financial statements.

Under Whiting Oil and Gas' credit agreement, a cross default provision provides that a default under certain other debt of the Company or certain of its subsidiaries in an aggregate principal amount exceeding $100 million may constitute an event of default under such credit agreement. Additionally, under the indentures governing our senior notes and senior convertible notes, a cross-default provision provides that a default under certain other debt of the Company or certain of its subsidiaries in an aggregate principal amount exceeding $100 million (or $50 million in the case of the 2021 Senior Notes) may constitute an event of default under such indenture.

Senior Notes. In December 2017, we issued at par $1.0 billion of 6.625% Senior Notes due January 15, 2026 (the "2026 Senior Notes"). In March 2015, we issued at par $750 million of 6.25% Senior Notes due April 1, 2023 (the

“2023 Senior Notes”). In September 2013, we issued at par $1.1 billion of 5.0% Senior Notes due March 15, 2019 (the “2019 Senior Notes”) and $800 million of 5.75% Senior Notes due March 15, 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 15, 2021 (collectively the “2021 Senior Notes” and together with the 2023 Senior Notes and the 2026 Senior Notes, the “Senior Notes”).

During 2016, we exchanged (i) $139 million aggregate principal amount of our 2019 Senior Notes, (ii) $326 million aggregate principal amount of our 2021 Senior Notes, and (iii) $342 million aggregate principal amount of our 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $807 million aggregate principal amount of these convertible notes was converted into approximately 19.8 million shares of our common stock pursuant to the terms of the notes.

Redemption of 2019 Senior Notes. In January 2018, we paid $1.0 billion to redeem all of the then outstanding $961 million aggregate principal amount of our 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with proceeds from the issuance of our 2026 Senior Notes and borrowings under our credit agreement.

Repurchases of 2021 Senior Notes. In September 2019, we paid $24 million to repurchase $25 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 94.708% purchase price plus all accrued and unpaid interest on the notes. We financed the repurchases with cash and borrowings under our credit agreement.

In October 2019, we paid an additional $72 million to repurchase $75 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 95.467% purchase price plus all accrued and unpaid interest on the notes. We financed the repurchases with borrowings under our credit agreement. As of December 31, 2019, $774 million of 2021 Senior Notes remained outstanding.

2020 Convertible Senior Notes. In March 2015, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 1, 2020 (the “2020 Convertible Senior Notes”). During 2016, we exchanged $688 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million aggregate principal amount of these mandatory convertible senior notes was converted into approximately 17.8 million shares of our common stock pursuant to the terms of the notes.

In September 2019, we paid $299 million to complete a cash tender offer for $300 million aggregate principal amount of the 2020 Convertible Senior Notes, which payment consisted of the 99.0% purchase price plus all accrued and unpaid interest on the notes and associated transaction costs. We financed the tender offer with cash and borrowings under our credit agreement.

The remaining $262 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of December 31, 2019 are convertible exclusively at the holder’s option. Prior to January 1, 2020, the 2020 Convertible Senior Notes were convertible only upon the achievement of certain contingent market conditions. As of December 31, 2019, none of the contingent market conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met. On or after January 1, 2020, the 2020 Convertible Senior Notes are convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes are convertible at a current conversion rate of 6.4102 shares of Whiting’s common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate is subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, we will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. We have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at our election. Our intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. At maturity, we must settle all outstanding 2020 Convertible Senior Notes in cash. Our business plan includes the intent to settle the outstanding 2020 Convertible Senior Notes using borrowings under the credit agreement.

Note Covenants. The indentures governing the Senior Notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas’ credit agreement. Additionally, these indentures contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, make certain other restricted payments, redeem or repurchase our capital stock, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance

with these covenants as of December 31, 2019. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Shelf Registration Statement. We have on file with the SEC a universal shelf-registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of December 31, 2019 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below. This table does not include amounts payable under contracts where we cannot predict with accuracy the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent upon the price of crude oil in effect at the time of settlement, and any penalties that may be incurred for underdelivery under our physical delivery contracts. For further information on these contracts refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements and "Delivery Commitments" in Item 2 of this Annual Report on Form 10-K.

	Payments due by period (in thousands)				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt [1]	$2,818,980	$ 262,075	$ 773,609	$ 783,296	$ 1,000,000
Cash interest expense on debt [2]	602,685	156,997	232,427	144,434	68,827
Asset retirement obligations [3]	134,893	3,685	34,696	17,464	79,048
Water disposal agreement [4]	82,763	20,318	37,328	25,117	-
Operating leases [5]	46,677	8,886	11,913	8,927	16,951
Pipeline transportation agreements [6]	18,044	6,327	8,981	2,736	-
Finance leases [5]	26,773	6,642	10,501	7,095	2,535
Purchase obligations [7]	7,656	7,656	-	-	-
Total	$3,738,471	$ 472,586	$1,109,455	$ 989,069	$ 1,167,361

(1) Long-term debt consists of the outstanding principal amounts of the Senior Notes and the 2020 Convertible Senior Notes, as well as the outstanding borrowings under our credit agreement. The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 2020 Convertible Senior Notes) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. As of December 31, 2019, we had $774 million aggregate principal amount of senior notes due March 15, 2021 and $408 million aggregate principal amount of senior notes due April 1, 2023. Our business plan includes the intent to refinance certain senior notes, including our convertible senior notes due in 2020 and our senior notes due in 2021, as permitted by the September 13, 2019 amendment to the credit agreement. Consequently, we have classified the credit agreement as long-term debt.

(2) Cash interest expense on the Senior Notes is estimated assuming no further principal repayment until the due dates of the instruments. Cash interest expense on the 2020 Convertible Senior Notes is estimated assuming no further principal repayments or conversions prior to maturity. Cash interest expense on the credit agreement is estimated assuming no principal borrowings or repayments through the April 2023 instrument due date and a fixed interest rate of 3.9%. Commitment fees on the credit agreement are estimated assuming no principal borrowings or repayments or changes to commitments through the April 2023 instrument due date.

(3) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants, facilities and offshore platforms.

(4) We have a water disposal agreement which expires in 2024 under which we have contracted for the transportation and disposal of the produced water from our Redtail field. Under the terms of the agreement, we are obligated to provide a minimum volume of produced water or else pay for any deficiencies at the price stipulated in the contract. As a result of our reduced development

operations at our Redtail field, we have made and expect to continue to make deficiency payments under this contract. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements for more information on this contract and the related deficiency payments.

(5) We have operating and finance leases for corporate and field offices, pipeline and midstream facilities and automobiles. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above. Refer to the "Leases" footnote in the notes to the consolidated financial statements for more information on these leases.

(6) Our pipeline transportation agreements consist of contracts through 2024 with various third parties to facilitate the delivery of our produced oil, gas and NGLs to market. These contracts require either fixed monthly reservation fees or commitments to deliver minimum volumes at fixed rates in exchange for dedicated pipeline capacity. If minimum volume commitments are not met, we are required to pay any deficiencies at the prices stipulated in the contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

(7) We have one take-or-pay purchase agreement which expires in 2020, whereby we have committed to buy certain volumes of water for use in the fracture stimulation process on wells we complete in our Redtail field. Under the terms of the agreement, we are obligated to purchase a minimum volume of water or else pay for any deficiencies at the prices stipulated in the contract. As a result of our reduced development operations in this field, we have made and expect to continue to make deficiency payments under this contract. Refer to the "Commitments and Contingencies" footnote in the notes to the consolidated financial statements for more information on this contract and the related deficiency payments.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operating, development and exploration activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the "Summary of Significant Accounting Policies" footnote in the notes to the consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements in accordance with GAAP and SEC rules and regulations requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, political environment, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in the "Summary of Significant Policies" footnote in the notes to the consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Successful Efforts Accounting. We account for our oil and gas operations using the successful efforts method of accounting. Under this method, the fair value of property acquired and all costs associated with successful exploratory wells and all development wells are capitalized. Items charged to expense generally include geological and geophysical costs, costs of unsuccessful exploratory wells and oil and gas production costs. All of our properties are located within the continental United States.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties and our asset retirement obligations. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates is a function of (i) the quality and quantity of available data, (ii) the interpretation of that data, (iii) the accuracy of various mandated economic assumptions, and (iv) the judgments of the persons preparing the estimates.

External petroleum engineers independently estimated all of the proved reserve quantities included in this Annual Report on Form 10-K. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data, (4) our well ownership interests and (5) expected future development activity. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2019. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. For example, if the crude oil and natural gas prices used in our year-end reserve estimates increased or decreased by 10%, our proved reserve quantities at December 31, 2019 would have increased by 9 MMBOE (2%) or decreased by 33 MMBOE (7%), respectively, and the pre-tax PV10% of our proved reserves would have increased by $0.9 billion (23%) or decreased by $0.8 billion (22%), respectively. We continually make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates and impairment calculations (when impairment indicators arise) in the same period that changes to reserve estimates are made.

Depreciation, Depletion and Amortization. Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. We review the value of our oil and gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Such events and circumstances include, but are not limited to, declines in commodity prices, increases in operating costs, unfavorable reserve revisions, poor well performance, changes in development plans and potential property divestitures. Impairments of producing properties are determined by comparing their undiscounted future net cash flows to their net book values at the end of each period. If a property's net capitalized costs exceed undiscounted future net cash flows, the cost of the property is written down to "fair value," which is determined using discounted future net cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. In addition to proved property impairments, we provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred. Individually insignificant unproved properties are amortized on a composite basis, based on past success, experience and average lease-term lives.

Asset Retirement Obligation. Our asset retirement obligations ("ARO") consist of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws and the terms of our lease agreements. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate; the inflation rate; and future advances in technology. In periods subsequent to the initial measurement of an ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Derivative Instruments. All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion or other derivative scope exceptions. We do not currently apply hedge accounting to any of our outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

We determine the recorded amounts of our derivative instruments measured at fair value utilizing third-party valuation specialists. We review these valuations, including the related model inputs and assumptions, and analyze changes in fair value measurements between periods. We corroborate such inputs, calculations and fair value changes using various methodologies, and review unobservable inputs for reasonableness utilizing relevant information from other published sources. When available, we utilize counterparty valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as the assumptions used in these valuations are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize costless collars and swaps which are generally placed with major financial institutions, as well as crude oil sales and delivery contracts. We use hedging to help ensure that we have adequate funding for our capital programs and to manage returns on our drilling programs and acquisitions. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

We value our collars and swaps using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. We value our long-term crude oil sales and delivery contracts based on a probability-weighted income approach which considers various assumptions, including quoted spot prices for commodities, market differentials for crude oil and U.S. Treasury rates. The discount rates used in the fair values of these instruments include a measure of nonperformance risk by the counterparty or us, as appropriate.

In addition, we evaluate the terms of our convertible debt and other contracts, if any, to determine whether they contain embedded components that are required to be bifurcated and accounted for separately as derivative financial instruments.

Income Taxes and Uncertain Tax Positions. We provide for income taxes in accordance with FASB ASC Topic 740 – *Income Taxes* (“ASC 740”). We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of our deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions, particularly as they relate to prevailing oil and natural gas prices.

On December 22, 2017, Congress passed the Tax Cuts and Jobs Act (the “TCJA”). The new legislation significantly changed the U.S. corporate tax law by, among other things, lowering the U.S. corporate income tax rate from 35% to 21% beginning in January 2018, implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries. The SEC issued Staff Accounting Bulletin No. 118 (“SAB 118”), which allowed registrants to record provisional amounts during a one-year “measurement period” similar to that used to account for business combinations, however, the measurement period was deemed to have ended earlier once the registrant had obtained, prepared and analyzed the information necessary to finalize its accounting. During the measurement period, impacts of the law were to be recorded at the time a reasonable estimate for all or a portion of the effects could be made, and provisional amounts recognized and adjusted as information became available, prepared or analyzed. As a result of the new legislation, we recognized the provisional impacts of the revaluation of our deferred tax assets and liabilities as of the date of enactment. We did not recognize any measurement period adjustments to these provisional amounts, and as of December 31, 2018, our accounting for the TCJA was complete.

ASC 740 requires uncertain income tax positions to meet a more-likely-than-not realization threshold to be recognized in the financial statements. Under ASC 740, uncertain tax positions that previously failed to meet the more-likely-than-not threshold should be recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized uncertain tax positions that no longer meet the more-likely-than-not threshold should be derecognized in the first subsequent financial reporting period in which that threshold is no longer met.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these

liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition. We predominantly derive our revenue from the sale of produced oil, NGLs and natural gas. Revenue is recognized when we meet our performance obligation to deliver the product and control is transferred to the customer. We receive payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the amount of production delivered and the price we will receive can be reasonably estimated and amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. Variances between our estimated revenue and actual payments are recorded in the month the payment is received. However, differences have been and are insignificant.

Accounting for Business Combinations. We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 – *Business Combinations*, and involves the use of significant judgment.

Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess, if any, of the consideration given to acquire an entity over the net amounts assigned to its assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity is recognized immediately to earnings as a gain from bargain purchase.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present values of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

The business combinations completed during the prior three years consisted of oil and gas properties. In general, the consideration we have paid to acquire these properties or companies was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition and consequently, there was no goodwill nor any bargain purchase gains recognized on our business combinations.

Leases. We have operating and finance leases for corporate and field offices, pipeline and midstream facilities, field and office equipment and automobiles. Right-of-use (“ROU”) assets and liabilities associated with these leases are recognized at the lease commencement date based on the present value of the lease payments over the lease term. ROU assets represent our right to use an underlying asset for the lease term, and lease liabilities represent our obligation to make lease payments.

Operating lease cost is recognized on a straight-line basis over the lease term. Finance lease cost is recognized based on the effective interest method for the lease liability and straight-line amortization of the ROU asset, resulting in more cost being recognized in earlier lease periods. All payments for short-term leases, including leases with a term of one month or less, are recognized in income or capitalized to the cost of oil and gas properties on a straight-line basis over the lease term. Additionally, any variable payments, which are generally related to the corresponding utilization of the asset, are recognized in the period in which the obligation was incurred.

We adopted FASB ASC Topic 842 – *Leases* effective January 1, 2019 using the modified retrospective approach. Refer to the “Summary of Significant Accounting Policies” and “Leases” footnotes in the notes to the consolidated financial statements for more information on this new accounting standard.

Effects of Inflation and Pricing

As commodity prices have begun to recover from previous lows during 2018 and 2019, the cost of oil field goods and services has also risen. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of our credit agreement, depletion expense, impairment assessments of oil and gas properties and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas

companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase in the near term, higher demand in the industry could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be "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. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we "expect", "intend", "plan", "estimate", "anticipate", "believe" or "should" or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: declines in, or extended periods of low oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness, our ability to comply with debt covenants, periodic redeterminations of the borrowing base under our credit agreement and our ability to generate sufficient cash flows from operations to service our indebtedness; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations; the impact of negative shifts in investor sentiment towards the oil and gas industry; impacts resulting from the allocation of resources among our strategic opportunities; the geographic concentration of our operations; impacts to financial statements as a result of impairment write-downs and other cash and noncash charges; federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; inaccuracies of our reserve estimates or our assumptions underlying them; the timing of our exploration and development expenditures; risks relating to decreases in our credit rating; our inability to access oil and gas markets due to market conditions or operational impediments; market availability of, and risks associated with, transport of oil and gas; our ability to successfully complete asset dispositions and the risks related thereto; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; weakened differentials impacting the price we receive for oil and natural gas; risks relating to any unforeseen liabilities of ours; the impacts of hedging on our results of operations; adverse weather conditions that may negatively impact development or production activities; uninsured or underinsured losses resulting from our oil and gas operations; lack of control over non-operated properties; failure of our properties to yield oil or gas in commercially viable quantities; the impact and costs of compliance with laws and regulations governing our oil and gas operations; the potential impact of changes in laws that could have a negative effect on the oil and gas industry; impacts of local regulations, climate change issues, negative public perception of our industry and corporate governance standards; our ability to replace our oil and natural gas reserves; negative impacts from litigation and legal proceedings; unforeseen underperformance of or liabilities associated with acquired properties or other strategic partnerships or investments; competition in the oil and gas industry; any loss of our senior management or technical personnel; cybersecurity attacks or failures of our telecommunication and other information technology infrastructure; and other risks described under the caption "Risk Factors" in Item 1A of this Annual Report on Form 10-K. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Annual Report on Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars and swaps, although we evaluate and have entered into other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Crude Oil Collars, Swaps and Options. Our hedging portfolio currently consists of collars, swaps and options. Refer to the "Derivative Financial Instruments" footnote in the notes to the consolidated financial statements for a description and list of our outstanding derivative contracts at December 31, 2019, as well as derivative contracts established subsequent to that date.

Our collars and options have the effect of providing a protective floor while allowing us to share in upward pricing movements. The fair value of our crude oil collars and options at December 31, 2019 was a net liability of $3 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2019 would cause an increase of $26 million or a decrease of $19 million, respectively, in this fair value liability.

Our swap contracts entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. The fair value of our swaps at December 31, 2019 was a net liability of $7 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of December 31, 2019 would cause an increase or decrease, respectively, of $29 million in this fair value liability.

While these collars, options and fixed-price swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of price increases above the ceiling with respect to the hedges and options and upward price movements generally with respect to the fixed-price swaps.

Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. At December 31, 2019, our outstanding principal balance under our credit agreement was $375 million, and the weighted average interest rate on the outstanding principal balance was 3.3%. At December 31, 2019, the carrying amount approximated fair market value. Assuming a constant debt level of $375 million, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $4 million over a 12-month time period. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate senior notes, but changes in interest rates do affect the fair values of these notes.

The interest rate on our 2020 Convertible Senior Notes is fixed at 1.25%, and as such, we are not subject to any direct risk of loss related to fluctuations in interest rates. However, changes in interest rates do affect the fair value of this debt instrument, which could impact the amount of gain or loss that we recognize in earnings upon conversion of the notes. Refer to the "Long-Term Debt" and "Fair Value Measurements" footnotes in the notes to the consolidated financial statements for more information on the material terms and fair values of the 2020 Convertible Senior Notes.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

Opinion on the Financial Statements

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

We have also 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 (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2020, expressed an unqualified opinion on the Company's internal control over financial reporting.

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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Proved Oil and Natural Gas Property Depletion – Oil and Natural Gas Reserve Quantities – Refer to Notes 1, 2 and 8 to the financial statements

Critical Audit Matter Description

The Company's proved oil and natural gas properties are depleted using the units of production method and are evaluated for impairment by comparison to the future net cash flows of the underlying oil and natural gas reserves. The development of the Company's oil and natural gas reserve quantities and the related future net cash flows requires management to make significant estimates and assumptions related to the five-year development rule for proved undeveloped reserves and future oil and natural gas prices. The Company engages an independent reserve engineer to estimate oil and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions or engineering data could have a significant impact on the amount of depletion and any proved oil and gas impairment. The proved oil and gas properties balance was $7 billion, as of December 31, 2019, net of accumulated depreciation,

depletion and amortization. Depreciation, depletion and amortization expense was $816 million for the year ended December 31, 2019. No impairment was recognized during 2019.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's oil and natural gas reserve quantities and the related net cash flows including management's estimates and assumptions related to the five-year development rule and future oil and natural gas prices, required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas reserves quantities and estimates of the future net cash flows included the following, among others:

- We tested the operating effectiveness of controls related to the Company's estimation of oil and natural gas reserve quantities and the related future net cash flows, including controls relating to the five-year development plan and future oil and natural gas prices.

- We evaluated the reasonableness of management's five-year development plan by comparing the forecasts to:

    - Historical conversions of proved undeveloped oil and natural gas reserves into proved developed oil and natural gas reserves

    - Internal communications to management and the Board of Directors

    - Permits and approval for expenditures

    - Forecasted information by basin included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies

- With the assistance of our fair value specialists, we evaluated management's estimated future sales prices for oil and natural gas, by:

    - Understanding the methodology used by management for development of the future prices and comparing the estimated prices to an independently determined range of prices

    - Comparing management's estimates to published forward pricing indices and third-party industry sources

    - Evaluating the historical realized price differentials incorporated in the future oil and natural gas prices

    - Evaluating the experience, qualifications and objectivity of management's expert, an independent reservoir engineering firm, including performing analytical procedures on the reserve quantities

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2020

We have served as the Company's auditor since 2003.

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8,652	$ 13,607
Accounts receivable trade, net	308,249	294,468
Derivative assets	886	68,342
Prepaid expenses and other	13,196	22,009
Total current assets	330,983	398,426
Property and equipment:		
Oil and gas properties, successful efforts method	12,812,007	12,195,659
Other property and equipment	178,689	134,212
Total property and equipment	12,990,696	12,329,871
Less accumulated depreciation, depletion and amortization	(5,735,239)	(5,003,509)
Total property and equipment, net	7,255,457	7,326,362
Other long-term assets	50,281	34,785
TOTAL ASSETS	$ 7,636,721	$ 7,759,573
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 80,100	$ 42,520
Revenues and royalties payable	202,010	228,284
Accrued capital expenditures	64,263	73,178
Accrued interest	53,928	55,080
Accrued lease operating expenses	38,262	37,499
Accrued liabilities and other	53,597	33,872
Taxes payable	26,844	31,357
Derivative liabilities	10,285	-
Accrued employee compensation and benefits	21,125	35,141
Total current liabilities	550,414	536,931
Long-term debt	2,799,885	2,792,321
Asset retirement obligations	131,208	131,544
Operating lease obligations	31,722	-
Deferred income taxes	73,593	1,373
Other long-term liabilities	24,928	27,088
Total liabilities	3,611,750	3,489,257
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 225,000,000 shares authorized; 91,743,571 issued and 91,326,469 outstanding as of December 31, 2019 and 92,067,216 issued and 91,018,692 outstanding as of December 31, 2018	92	92
Additional paid-in capital	6,409,991	6,414,170
Accumulated deficit	(2,385,112)	(2,143,946)
Total equity	4,024,971	4,270,316
TOTAL LIABILITIES AND EQUITY	$ 7,636,721	$ 7,759,573

The accompanying notes are an integral part of these consolidated financial statements.

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)

	Year Ended December 31,		
	2019	**2018**	**2017**
OPERATING REVENUES			
Oil, NGL and natural gas sales	$ 1,572,245	$ 2,081,414	$ 1,481,435
OPERATING EXPENSES			
Lease operating expenses	328,427	311,895	278,919
Transportation, gathering, compression and other	42,438	48,105	90,574
Production and ad valorem taxes	138,212	171,823	120,870
Depreciation, depletion and amortization	816,488	781,329	948,939
Exploration and impairment	54,738	67,368	936,177
General and administrative	132,609	123,250	124,288
Derivative loss, net	53,769	17,170	122,847
Loss on sale of properties	1,964	1,949	401,113
Amortization of deferred gain on sale	(9,069)	(11,354)	(12,963)
Total operating expenses	1,559,576	1,511,535	3,010,764
INCOME (LOSS) FROM OPERATIONS	12,669	569,879	(1,529,329)
OTHER INCOME (EXPENSE)			
Interest expense	(191,047)	(197,474)	(191,088)
Gain (loss) on extinguishment of debt	7,830	(31,968)	(1,540)
Interest income and other	1,602	3,430	1,316
Total other expense	(181,615)	(226,012)	(191,312)
INCOME (LOSS) BEFORE INCOME TAXES	(168,946)	343,867	(1,720,641)
INCOME TAX EXPENSE (BENEFIT)			
Current	-	-	(7,291)
Deferred	72,220	1,373	(475,688)
Total income tax expense (benefit)	72,220	1,373	(482,979)
NET INCOME (LOSS)	(241,166)	342,494	(1,237,662)
Net loss attributable to noncontrolling interests	-	-	14
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ (241,166)	$ 342,494	$ (1,237,648)
INCOME (LOSS) PER COMMON SHARE			
Basic	$ (2.64)	$ 3.77	$ (13.65)
Diluted	$ (2.64)	$ 3.73	$ (13.65)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	91,285	90,953	90,683
Diluted	91,285	91,869	90,683

The accompanying notes are an integral part of these consolidated financial statements.

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2019	**2018**	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ (241,166)	$ 342,494	$ (1,237,662)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	816,488	781,329	948,939
Deferred income tax expense (benefit)	72,220	1,373	(475,688)
Amortization of debt issuance costs, debt discount and debt premium	28,340	30,700	31,715
Stock-based compensation	7,721	12,669	21,641
Amortization of deferred gain on sale	(9,069)	(11,354)	(12,963)
Loss on sale of properties	1,964	1,949	401,113
Oil and gas property impairments	17,866	45,288	899,853
(Gain) loss on extinguishment of debt	(7,830)	31,968	1,540
Non-cash derivative (gain) loss	78,626	(139,831)	131,129
Payment for settlement of commodity derivative contract	-	(61,036)	-
Other, net	(1,352)	(6,706)	(9,255)
Changes in current assets and liabilities:			
Accounts receivable trade, net	(24,343)	(11,571)	(110,879)
Prepaid expenses and other	7,165	4,026	(444)
Accounts payable trade and accrued liabilities	40,117	11,368	(24,953)
Revenues and royalties payable	(26,274)	56,751	23,799
Taxes payable	(4,513)	2,586	(10,776)
Net cash provided by operating activities	755,960	1,092,003	577,109
CASH FLOWS FROM INVESTING ACTIVITIES			
Drilling and development capital expenditures	(793,365)	(813,981)	(830,552)
Acquisition of oil and gas properties	(6,031)	(142,723)	(21,429)
Other property and equipment	(6,451)	(1,096)	(4,596)
Proceeds from sale of properties	72,000	4,746	929,974
Net cash provided by (used in) investing activities	(733,847)	(953,054)	73,397
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings under credit agreement	2,650,000	2,214,265	1,900,000
Repayments of borrowings under credit agreement	(2,275,000)	(2,214,265)	(2,450,000)
Issuance of 6.625% Senior Notes due 2026	-	-	1,000,000
Redemption of 6.5% Senior Subordinated Notes due 2018	-	-	(275,121)
Redemption of 5.0% Senior Notes due 2019	-	(990,023)	-
Repurchase of 1.25% Convertible Senior Notes due 2020	(297,000)	-	-
Repurchase of 5.75% Senior Notes due 2021	(95,279)	-	-
Debt issuance and extinguishment costs	(819)	(10,709)	(13,150)
Restricted stock used for tax withholdings	(3,830)	(4,744)	(6,081)
Proceeds from stock options exercised	-	755	-
Principal payments on finance lease obligations	(5,140)	-	-
Net cash provided by (used in) financing activities	$ (27,068)	$ (1,004,721)	$ 155,648

(Continued)

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2019	**2018**	**2017**
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ (4,955)	$ (865,772)	$ 806,154
CASH AND CASH EQUIVALENTS			
Beginning of period	13,607	879,379	73,225
End of period	$ 8,652	$ 13,607	$ 879,379
SUPPLEMENTAL CASH FLOW DISCLOSURES			
Income taxes paid (refunded), net	$ (7,508)	$ (32)	$ 49
Interest paid, net of amounts capitalized	$ 163,859	$ 152,665	$ 163,151
NONCASH INVESTING ACTIVITIES			
Accrued capital expenditures and accounts payable related to property additions	$ 86,088	$ 90,358	$ 80,762
Leasehold improvements paid for by third party lessor under office lease agreement	$ 10,422	$ -	$ -
NONCASH FINANCING ACTIVITIES [(1)]			

(Concluded)

(1) Refer to the “Leases” footnote in the notes to the consolidated financial statements for discussion of right-of-use assets obtained in exchange for finance lease liabilities.

The accompanying notes are an integral part of these consolidated financial statements.

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
(in thousands)

	Common Stock Shares [(1)]	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity
BALANCES - January 1, 2017	91,793	$ 367	$6,389,435	$ (1,248,572)	$ 5,141,230	$ 7,962	$ 5,149,192
Net loss	-	-	-	(1,237,648)	(1,237,648)	(14)	(1,237,662)
Conveyance of third party ownership interest in Sustainable Water Resources, LLC	-	-	-	-	-	(7,948)	(7,948)
Reverse stock split	-	(276)	276	-	-	-	-
Restricted stock issued	707	2	(2)	-	-	-	-
Restricted stock forfeited	(261)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(144)	-	(6,081)	-	(6,081)	-	(6,081)
Stock-based compensation	-	-	21,641	-	21,641	-	21,641
Cumulative effect of change in accounting principle	-	-	220	(220)	-	-	-
BALANCES - December 31, 2017	92,095	92	6,405,490	(2,486,440)	3,919,142	-	3,919,142
Net income	-	-	-	342,494	342,494	-	342,494
Exercise of stock options	16	-	755	-	755	-	755
Restricted stock issued	451	-	-	-	-	-	-
Restricted stock forfeited	(351)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(144)	-	(4,744)	-	(4,744)	-	(4,744)
Stock-based compensation	-	-	12,669	-	12,669	-	12,669
BALANCES - December 31, 2018	92,067	92	6,414,170	(2,143,946)	4,270,316	-	4,270,316
Net loss	-	-	-	(241,166)	(241,166)	-	(241,166)
Adjustment to equity component of 2020 Convertible Senior Notes upon partial extinguishment	-	-	(8,070)	-	(8,070)	-	(8,070)
Restricted stock issued	113	-	-	-	-	-	-
Restricted stock forfeited	(286)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(150)	-	(3,830)	-	(3,830)	-	(3,830)
Stock-based compensation	-	-	7,721	-	7,721	-	7,721
BALANCES - December 31, 2019	91,744	$ 92	$6,409,991	$ (2,385,112)	$ 4,024,971	$ -	$ 4,024,971

(1) In November 2017, the Company effected a one-for-four reverse stock split, as described in the "Shareholders' Equity and Noncontrolling Interest" footnote to these consolidated financial statements. All common shares amounts prior to November 2017 have been retroactively adjusted to reflect this reverse stock split.

The accompanying notes are an integral part of these consolidated financial statements.

WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company engaged in the development, production, acquisition and exploration of crude oil, NGLs and natural gas primarily in the Rocky Mountains region of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation and its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements have been prepared in accordance with GAAP and SEC rules and regulations and include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Items subject to such estimates and assumptions include (i) oil and natural gas reserves; (ii) impairment tests of long-lived assets; (iii) depreciation, depletion and amortization; (iv) asset retirement obligations; (v) assignment of fair value and allocation of purchase price in connection with business combinations, including the determination of any resulting goodwill; (vi) income taxes; (vii) accrued liabilities; (viii) valuation of derivative instruments; and (ix) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates. Further, these estimates and other factors, including those outside of the Company's control, such as the impact of lower commodity prices, may have a significant negative impact to the Company's business, financial condition, results of operations and cash flows.

Cash and Cash Equivalents—Cash equivalents consist of demand deposits and highly liquid investments which have an original maturity of three months or less.

Accounts Receivable Trade—Whiting's accounts receivable trade consist mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, Whiting typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected within two months, and to date, the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. At December 31, 2019 and 2018, the Company had an allowance for doubtful accounts of $9 million and $12 million, respectively.

Inventories—Materials and supplies inventories consist primarily of tubular goods and production equipment, carried at weighted-average cost. Materials and supplies are included in other property and equipment and totaled $39 million and $23 million as of December 31, 2019 and 2018, respectively. Crude oil in tanks inventory is carried at the lower of the estimated cost to produce or net realizable value. Oil in tanks is included in prepaid expenses and other and totaled $6 million and $5 million as of December 31, 2019 and 2018, respectively.

Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a unit-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. Costs of drilling exploratory wells are initially capitalized but are charged to expense if the well is determined to be unsuccessful.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. Such events include, but are not limited to, declines in commodity prices, increases in

operating costs, unfavorable reserve revisions, poor well performance, changes in development plans and potential property divestitures. The impairment test compares undiscounted future net cash flows to the assets' net book value. These undiscounted cash flows are driven by significant assumptions, including the Company's expected future development activity, reserve estimates, forecasted pricing, future operating costs, capital expenditures and severance taxes. If the net capitalized costs exceed undiscounted future net cash flows, then the cost of the property is written down to fair value utilizing a discounted future net cash flow analysis.

Impairment expense for proved properties totaled $835 million for the year ended December 31, 2017, which is reported in exploration and impairment expense.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

Unproved. Unproved properties consist of costs to acquire undeveloped leases as well as purchases of unproved reserves. Undeveloped lease costs and unproved reserve acquisitions are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on average lease-term lives and the historical experience of developing acreage in a particular prospect. The Company evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense for unproved properties totaled $9 million, $37 million and $59 million for the years ended December 31, 2019, 2018 and 2017, respectively, which is reported in exploration and impairment expense.

Exploratory. Geological and geophysical costs, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

Costs of drilling exploratory wells are initially capitalized, pending determination of whether the well has found proved reserves. If an exploratory well has not found proved reserves, the costs of drilling the well and other associated costs are charged to expense. Costs incurred for exploratory wells that find reserves, which cannot yet be classified as proved, continue to be capitalized if (i) the well has found a sufficient quantity of reserves to justify completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if the Company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well costs, net of any salvage value, are expensed.

Other Property and Equipment—Other property and equipment consists of materials and supplies inventories, carried at weighted-average cost, and furniture and fixtures, buildings and leasehold improvements, which are stated at cost and depreciated using the straight-line method over their estimated useful lives ranging from 4 to 30 years. Additionally, other property and equipment includes finance lease right-of-use assets for pipeline and midstream facilities, field and office equipment and automobiles, which are depreciated using the straight-line method over their estimated useful lives ranging from 5 to 30 years. Refer to the "Leases" footnote for additional information on these lease assets.

Debt Issuance Costs**—**Debt issuance costs related to the Company's senior notes and convertible senior notes are included as a deduction from the carrying amount of long-term debt in the consolidated balance sheets and are amortized to interest expense using the effective interest method over the term of the related debt. Debt issuance costs related to the credit facility are included in other long-term assets and are amortized to interest expense on a straight-line basis over the term of the agreement.

Debt Discounts and Premiums—Debt discounts and premiums related to the Company's senior notes and convertible senior notes are included as a deduction from or addition to the carrying amount of the long-term debt in the consolidated balance sheets and are amortized to interest expense using the effective interest method over the term of the related notes.

Derivative Instruments—The Company enters into derivative contracts, primarily collars, swaps and options, to manage its exposure to commodity price risk. Whiting follows FASB ASC Topic 815 – *Derivatives and Hedging,* to account for its derivative financial

instruments. All derivative instruments, other than those that meet the "normal purchase normal sale" exclusion, are recorded on the balance sheet as either an asset or liability measured at fair value. Gains and losses from changes in the fair value of derivative instruments are recognized immediately in earnings, unless the derivative meets specific hedge accounting criteria and the derivative has been designated as a hedge. The Company does not currently apply hedge accounting to any of its outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

Cash flows from derivatives used to manage commodity price risk are classified in operating activities along with the cash flows of the underlying hedged transactions. The Company does not enter into derivative instruments for speculative or trading purposes. Refer to the "Derivative Financial Instruments" footnote for further information.

Asset Retirement Obligations and Environmental Costs—Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The Company follows FASB ASC Topic 410 – *Asset Retirement and Environmental Obligations*, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when a well is completed or acquired or when an asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a unit-of-production basis over the proved developed reserves of the related asset. Revisions typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells, and such revisions result in adjustments to the related capitalized asset and corresponding liability.

Liabilities for environmental costs are recorded on an undiscounted basis when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties.

Deferred Gain on Sale—The deferred gain on sale relates to the sale of 18,400,000 Whiting USA Trust II ("Trust II") units, and is amortized to income based on the unit-of-production method.

Revenue Recognition—Revenues are predominantly derived from the sale of produced oil, NGLs and natural gas. The Company accounts for revenues in accordance with FASB ASC Topic 606 – *Revenue from Contracts with Customers*, and thus oil and gas revenues are recognized when the performance obligation to deliver the product is met and control is transferred to the customer. Payments for product sales are received one to three months after delivery. At the end of each month when the performance obligation is satisfied and the amount of production delivered and the price received can be reasonably estimated, amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. Variances between estimated revenue and actual payments are recorded in the month the payment is received. However, differences have been and are insignificant.

Taxes collected and remitted to governmental agencies on behalf of customers are not included in revenues or costs and expenses.

General and Administrative Expenses—General and administrative expenses are reported net of reimbursements of overhead costs that are allocated to the working interest owners that participate in oil and gas properties operated by Whiting.

Stock-based Compensation Expense—The Company has share-based employee compensation plans that provide for the issuance of various types of stock-based awards, including shares of restricted stock, restricted stock units, performance shares, performance share units and stock options, to employees and non-employee directors. The Company determines compensation expense for share-settled awards granted under these plans based on the grant date fair value, and such expense is recognized on a straight-line basis over the requisite service period of the award. The Company determines compensation expense for cash-settled awards granted under these plans based on the fair value of such awards at the end of each reporting period. Cash-settled awards are recorded as a liability in the consolidated balance sheets, and gains and losses from changes in fair value are recognized immediately in earnings. The Company accounts for forfeitures of share-based awards as they occur. Refer to the "Stock-Based Compensation" footnote for further information.

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. The Company's contributions for 2019, 2018 and

2017 were $7 million, $7 million and $8 million, respectively. Employees vest in employer contributions at 20% per year of completed service up to five years.

Acquisition Costs—Acquisition related expenses, which consist of external costs directly related to the Company's acquisitions, such as advisory, legal, accounting, valuation and other professional fees, are expensed as incurred.

Maintenance and Repairs—Maintenance and repair costs that do not extend the useful lives of property and equipment are charged to expense as incurred. Major replacements, renewals and betterments are capitalized.

Income Taxes—Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are determined by applying the enacted statutory tax rates in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is established when it is more likely than not that some portion of the benefit from deferred tax assets will not be realized. The Company's uncertain tax positions must meet a more-likely-than-not realization threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income attributable to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted and performance stock awards and units, outstanding stock options and contingently issuable shares of convertible debt to be settled in cash, all using the treasury stock method. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, NGLs and natural gas. The Company considers its gathering, processing and marketing functions as ancillary to its oil and gas producing activities. All of the Company's operations and assets are located in the United States, and substantially all of its revenues are attributable to United States customers.

Concentration of Credit Risk—Whiting is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy related industries. The creditworthiness of customers and other counterparties is subject to continuing review. The following tables present the percentages by purchaser that accounted for 10% or more of the Company's total oil, NGL and natural gas sales for the years ended December 31, 2019, 2018 and 2017.

Year Ended December 31, 2019	
Tesoro Crude Oil Co	14 %
Philips 66 Company	12 %

Year Ended December 31, 2018	
United Energy Trading, LLC	17 %
Tesoro Crude Oil Co	14 %
Philips 66 Company	11 %

Year Ended December 31, 2017	
Tesoro Crude Oil Co	18 %

Commodity derivative contracts held by the Company are with nine counterparties, all of which are participants in Whiting's credit facility and all of which have investment-grade ratings from Moody's and Standard & Poor's. As of December 31, 2019, outstanding derivative contracts with Capital One, N.A., JP Morgan Chase Bank, N.A., the Bank of Nova Scotia, Merrill Lynch Commodities, Inc. and Citibank, N.A. represented 28%, 16%, 14%, 13% and 11%, respectively, of total crude oil volumes hedged.

Adopted and Recently Issued Accounting Pronouncements—In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases* ("ASU 2016-02"). The objective of this ASU is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. The FASB subsequently issued various ASUs which provided additional implementation guidance, and these ASUs collectively make up FASB

ASC Topic 842 – *Leases* (“ASC 842”). ASC 842 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. The standard permits retrospective application through recognition of a cumulative-effect adjustment at the beginning of either the earliest reporting period presented or the period of adoption. The Company adopted ASC 842 effective January 1, 2019 using the modified retrospective method as of the adoption date. Whiting has completed the assessment of its existing accounting policies and documentation, implementation of lease accounting software and enhancement of its internal controls. Adoption of the standard resulted in the recognition of additional lease assets and liabilities on Whiting’s consolidated balance sheet as well as additional disclosures. The adoption did not have a material impact to the Company’s consolidated statement of operations. Refer to the “Leases” footnote for further information on the Company’s implementation of this standard.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company’s oil and gas producing activities at December 31, 2019 and 2018 are as follows (in thousands):

	December 31,	
	2019	**2018**
Costs of completed wells and facilities	$ 9,847,159	$ 9,182,384
Proved leasehold costs	2,702,236	2,729,593
Wells and facilities in progress	159,334	160,995
Unproved leasehold costs	103,278	122,687
Total oil and gas properties, successful efforts method	12,812,007	12,195,659
Accumulated depletion	(5,656,929)	(4,937,579)
Oil and gas properties, net	$ 7,155,078	$ 7,258,080

3. ACQUISITIONS AND DIVESTITURES

2019 Acquisitions and Divestitures

On July 29, 2019, the Company completed the divestiture of its interests in 137 non-operated, producing oil and gas wells located in the McKenzie, Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $27 million (before closing adjustments).

On August 15, 2019, the Company completed the divestiture of its interests in 58 non-operated, producing oil and gas wells located in Richland County, Montana and Mountrail and Williams counties of North Dakota for aggregate sales proceeds of $26 million (before closing adjustments).

There were no significant acquisitions during the year ended December 31, 2019.

2018 Acquisitions and Divestitures

On July 31, 2018, the Company completed the acquisition of certain oil and gas properties located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The properties consist of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage. The revenue and earnings from these properties since the acquisition date are included in the Company’s consolidated financial statements for the year ended December 31, 2018 and are not material. Pro forma revenue and earnings for the acquired properties are not material to the Company’s consolidated financial statements and have not been presented accordingly.

The acquisition was recorded using the acquisition method of accounting. The following table summarizes the allocation of the $123 million adjusted purchase price to the tangible assets acquired and liabilities assumed in this acquisition based on their relative fair values at the acquisition date, which did not result in the recognition of goodwill or a bargain purchase gain (in thousands):

Cash consideration	$	122,861
Fair value of assets acquired:		
Accounts receivable trade, net	$	30
Prepaid expenses and other		43
Oil and gas properties, successful efforts method:		
Proved oil and gas properties		106,860
Unproved oil and gas properties		21,769
Total fair value of assets acquired		128,702
Fair value of liabilities assumed:		
Revenue and royalties payable		3,309
Asset retirement obligations		2,532
Total fair value of liabilities assumed		5,841
Total fair value of assets and liabilities acquired	$	122,861

2017 Acquisitions and Divestitures

On January 1, 2017, the Company completed the sale of its 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and its 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments). The Company used the net proceeds from this transaction to repay a portion of the debt outstanding under its credit agreement.

On September 1, 2017, the Company completed the sale of its interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, (the “FBIR Assets”) for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

There were no significant acquisitions during the year ended December 31, 2017.

4. LEASES

The Company adopted ASC 842 effective January 1, 2019, which replaces previous lease accounting requirements under FASB ASC Topic 840 – *Leases* (“ASC 840”). The standard was adopted using the modified retrospective approach which resulted in the recognition of approximately $30 million and $36 million of additional lease assets and liabilities, respectively, on the consolidated balance sheet upon adoption. The Company has elected certain practical expedients available under ASC 842 including those that permit the Company to not (i) reassess prior conclusions reached under ASC 840 for lease identification, lease classification and initial direct costs, (ii) evaluate existing or expired land easements under the new standard and (iii) separate lease and non-lease components contained within a single agreement for all classes of underlying assets. Accordingly, the adoption of the standard did not result in the Company recognizing a cumulative-effect adjustment to retained earnings. Additionally, the Company has elected the short-term lease recognition exemption for all classes of underlying assets, and therefore, leases with a term of one year or less have not and will not be recognized on the consolidated balance sheets.

The Company has operating and finance leases for corporate and field offices, pipeline and midstream facilities and automobiles. Right-of-use (“ROU”) assets and liabilities associated with these leases are recognized at the lease commencement date based on the present value of the lease payments over the lease term. ROU assets represent the Company’s right to use an underlying asset for the lease term, and lease liabilities represent the Company’s obligation to make lease payments.

Supplemental balance sheet information for the Company's leases as of December 31, 2019 consisted of the following (in thousands):

Leases	Balance Sheet Classification	December 31, 2019
Operating Leases		
Operating lease ROU assets	Other long-term assets	$ 31,882
Accumulated depreciation	Other long-term assets	(4,895)
Operating lease ROU assets, net		$ 26,987
Short-term operating lease obligations	Accrued liabilities and other	$ 7,346
Long-term operating lease obligations	Operating lease obligations	31,722
Total operating lease obligations		$ 39,068
Finance Leases		
Finance lease ROU assets	Other property and equipment	$ 33,312
Accumulated depreciation	Accumulated depreciation, depletion and amortization	(14,180)
Finance lease ROU assets, net		$ 19,132
Short-term finance lease obligations	Accrued liabilities and other	$ 4,974
Long-term finance lease obligations	Other long-term liabilities	16,638
Total finance lease obligations		$ 21,612

The Company's leases have remaining terms of less than one year to 10 years. Most of the Company's leases do not state or imply a discount rate. Accordingly, the Company uses its incremental borrowing rate based on information available at lease commencement to determine the present value of the lease payments. Information regarding the Company's lease terms and discount rates as of December 31, 2019 is as follows:

Weighted Average Remaining Lease Term	
Operating leases	8 years
Finance leases	5 years
Weighted Average Discount Rate	
Operating leases	4.6%
Finance leases	8.6%

Operating lease cost is recognized on a straight-line basis over the lease term. Finance lease cost is recognized based on the effective interest method for the lease liability and straight-line amortization of the ROU asset, resulting in more cost being recognized in earlier lease periods. All payments for short-term leases, including leases with a term of one month or less, are recognized in income or capitalized to the cost of oil and gas properties on a straight-line basis over the lease term. Additionally, any variable payments, which are generally related to the corresponding utilization of the asset, are recognized in the period in which the obligation was incurred. Lease cost for the year ended December 31, 2019 consisted of the following (in thousands):

	Year Ended December 31, 2019
Operating lease cost	$ 11,512
Finance lease cost:	
Amortization of ROU assets	$ 5,661
Interest on lease liabilities	1,996
Total finance lease cost	$ 7,657
Short-term lease payments	$ 676,850
Variable lease payments	$ 31,812

Total lease cost represents the total financial obligations of the Company, a portion of which has been or will be reimbursed by the Company's working interest partners. Lease cost is included in various line items on the consolidated statements of operations or capitalized to oil and gas properties and is recorded at the Company's net working interest.

Supplemental cash flow information related to leases for the year ended December 31, 2019 consisted of the following (in thousands):

	Year Ended December 31, 2019	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$	11,978
Operating cash flows from finance leases	$	2,006
Financing cash flows from finance leases	$	5,140
ROU assets obtained in exchange for new operating lease obligations	$	18,658
ROU assets obtained in exchange for new finance lease obligations	$	4,158

The Company's lease obligations as of December 31, 2019 will mature as follows (in thousands):

Year ending December 31,	Operating Leases		Finance Leases	
2020	$	8,886	$	6,642
2021		6,657		5,753
2022		5,256		4,748
2023		4,592		3,849
2024		4,335		3,246
Remaining		16,951		2,535
Total lease payments	$	46,677	$	26,773
Less imputed interest		(7,609)		(5,161)
Total discounted lease payments	$	39,068	$	21,612

As of December 31, 2019, the Company had a contract for an additional corporate office space that consists of approximately $16 million of undiscounted minimum lease payments. The operating lease has a nine-year lease term and is expected to commence in June 2020.

As of December 31, 2018, minimum future contractual payments for long-term leases under the scope of ASC 840 were as follows (in thousands):

Year ending December 31,	Real Estate Leases		Pipeline Transportation Agreement		Automobile and Equipment Leases	
2019	$	7,407	$	3,180	$	4,216
2020		4,770		3,180		3,422
2021		4,066		3,180		1,678
2022		4,188		3,180		488
2023		4,017		3,180		35
Remaining		25,140		5,565		-
Total lease payments	$	49,588	$	21,465	$	9,839

5. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	2018
Credit agreement	$ 375,000	$ -
1.25% Convertible Senior Notes due 2020	262,075	562,075
5.75% Senior Notes due 2021	773,609	873,609
6.25% Senior Notes due 2023	408,296	408,296
6.625% Senior Notes due 2026	1,000,000	1,000,000
Total principal	2,818,980	2,843,980
Unamortized debt discounts and premiums	(2,575)	(28,994)
Unamortized debt issuance costs on notes	(16,520)	(22,665)
Total long-term debt	$ 2,799,885	$ 2,792,321

Credit Agreement

Whiting Oil and Gas, the Company's wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of December 31, 2019 had a borrowing base of $2.05 billion and aggregate commitments of $1.75 billion. As of December 31, 2019, the Company had $1.4 billion of available borrowing capacity under the credit agreement, which was net of $375 million of borrowings outstanding and $2 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of the borrowing base, either on a periodic or special redetermination date, if total outstanding credit exposure exceeds the redetermined borrowing base, the Company will be required to prepay outstanding borrowings in an aggregate principal amount equal to such excess in six substantially equal monthly installments. In October 2019, the borrowing base under the credit agreement was reduced from $2.25 billion to $2.05 billion in connection with the semi-annual regular borrowing base redetermination, with no change to the aggregate commitments of $1.75 billion.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of December 31, 2019, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. Interest under the credit agreement accrues at the Company's option at either (i) a base rate for a base rate loan plus a margin between 0.50% and 1.50% based on the ratio of outstanding borrowings to the borrowing base, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus a margin between 1.50% and 2.50% based on the ratio of outstanding borrowings to the borrowing base. Additionally, the Company incurs commitment fees of 0.375% or 0.50% based on the ratio of outstanding borrowings to the borrowing base on the unused portion of the aggregate commitments of the lenders under the credit agreement, which are included as a component of interest expense. At December 31, 2019, the weighted average interest rate on the outstanding principal balance under the credit agreement was 3.3%.

The credit agreement matures on April 12, 2023, provided that if at any time and for so long as any senior notes (other than the 2020 Convertible Senior Notes) have a maturity date prior to 91 days after April 12, 2023, the maturity date shall be the date that is 91 days prior to the maturity of such senior notes. On September 13, 2019, the Company amended the credit agreement to, among other things, permit the repurchase, redemption, prepayment or other acquisition or retirement for value of any senior notes (as defined in the credit agreement) if: (i) such transaction is for a price not greater than an amount equal to par plus accrued and unpaid interest and fees and any applicable make-whole premium, (ii) immediately after giving effect to such transaction, there is unused availability under the facility of not less than the greater of $100 million or 15% of the then effective total commitments, and (iii) the Company's ratio of consolidated total debt as of the date of such transaction (upon giving effect thereto) to EBITDAX (as defined in the credit agreement) during the last four quarters is not greater than 3.25 to 1.0. The Company's business plan includes the intent to refinance certain senior

notes, including the convertible senior notes due in 2020 and the senior notes due in 2021, as permitted by the September 13, 2019 amendment to the credit agreement. Consequently, the Company has classified the credit agreement as long-term debt.

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the Company's restricted subsidiaries (as defined in the credit agreement). As of December 31, 2019, there were no retained earnings free from restrictions. The credit agreement requires the Company, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. As of December 31, 2019, the Company was in compliance with its covenants under the credit agreement.

Under Whiting Oil and Gas' credit agreement, a cross default provision provides that a default under certain other debt of the Company or certain of its subsidiaries in an aggregate principal amount exceeding $100 million may constitute an event of default under such credit agreement. Additionally, under the indentures governing our senior notes and senior convertible notes, a cross-default provision provides that a default under certain other debt of the Company or certain of its subsidiaries in an aggregate principal amount exceeding $100 million (or $50 million in the case of the 2021 Senior Notes) may constitute an event of default under such indenture.

The obligations of Whiting Oil and Gas under the credit agreement are collateralized by a first lien on substantially all of Whiting Oil and Gas' and Whiting Resource Corporation's properties. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of its subsidiaries as security for its guarantee.

Senior Notes, Convertible Senior Notes and Senior Subordinated Notes

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Senior Subordinated Notes").

In September 2013, the Company issued at par $1.1 billion of 5.0% Senior Notes due March 15, 2019 (the "2019 Senior Notes") and $800 million of 5.75% Senior Notes due March 15, 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 15, 2021 (collectively, the "2021 Senior Notes"). The debt premium recorded in connection with the issuance of the 2021 Senior Notes is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.5% per annum.

In March 2015, the Company issued at par $750 million of 6.25% Senior Notes due April 1, 2023 (the "2023 Senior Notes").

In December 2017, the Company issued at par $1.0 billion of 6.625% Senior Notes due January 15, 2026 (the "2026 Senior Notes" and together with the 2021 Senior Notes and the 2023 Senior Notes, the "Senior Notes"). The Company used the net proceeds from this offering to redeem in January 2018 all of the then outstanding 2019 Senior Notes. Refer to "Redemption of 2019 Senior Notes" below for more information on the redemption of the 2019 Senior Notes.

During 2016, the Company exchanged (i) $75 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $139 million aggregate principal amount of its 2019 Senior Notes, (iii) $326 million aggregate principal amount of its 2021 Senior Notes, and (iv) $342 million aggregate principal amount of its 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $882 million aggregate principal amount of these convertible notes was converted into approximately 21.6 million shares of the Company's common stock pursuant to the terms of the notes.

Redemption of 2018 Senior Subordinated Notes. In February 2017, the Company paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $2 million loss on extinguishment of debt.

Redemption of 2019 Senior Notes. In January 2018, the Company paid $1.0 billion to redeem all of the remaining $961 million aggregate principal amount of the 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with proceeds from the issuance of the 2026 Senior Notes and borrowings under its credit agreement. As a result of the redemption, the Company recognized a $31 million loss on extinguishment of debt.

Repurchases of 2021 Senior Notes. In September 2019, the Company paid $24 million to repurchase $25 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 94.708% purchase price plus all accrued and unpaid interest on the notes. The Company financed the repurchases with borrowings under its credit agreement. As a result of the repurchases, the Company recognized a $1 million gain on extinguishment of debt, which included a non-cash charge for the acceleration of unamortized debt issuance costs and debt premium on the notes.

In October 2019, the Company paid an additional $72 million to repurchase $75 million aggregate principal amount of the 2021 Senior Notes, which payment consisted of the average 95.467% purchase price plus all accrued and unpaid interest on the notes. The Company financed the repurchases with borrowings under its credit agreement. As a result of the repurchases, the Company recognized a $3 million gain on extinguishment of debt, which included a noncash charge for the acceleration of unamortized debt issuance costs and debt premium on the notes. As of December 31, 2019, $774 million of 2021 Senior Notes remained outstanding.

2020 Convertible Senior Notes—In March 2015, the Company issued at par $1,250 million of 1.25% Convertible Senior Notes due April 1, 2020 (the “2020 Convertible Senior Notes”) for net proceeds of $1.2 billion, net of initial purchasers’ fees of $25 million. During 2016, the Company exchanged $688 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million aggregate principal amount of these mandatory convertible notes was converted into approximately 17.8 million shares of the Company’s common stock pursuant to the terms of the notes.

In September 2019, the Company paid $299 million to complete a cash tender offer for $300 million aggregate principal amount of the 2020 Convertible Senior Notes, which payment consisted of the 99.0% purchase price plus all accrued and unpaid interest on the notes, which were allocated to the liability and equity components based on their relative fair values. The Company financed the tender offer with borrowings under its credit agreement. As a result of the tender offer, the Company recognized a $4 million gain on extinguishment of debt, which was net of a $7 million charge for the non-cash write-off of unamortized debt issuance costs and debt discount and a $1 million charge for transaction costs. In addition, the Company recorded an $8 million reduction to the equity component of the 2020 Convertible Senior Notes. There was no deferred tax impact associated with this reduction due to the full valuation allowance in effect as of September 30, 2019.

The remaining $262 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of December 31, 2019 are convertible exclusively at the holder’s option. Prior to January 1, 2020, the 2020 Convertible Senior Notes were convertible only upon the achievement of certain contingent market conditions. As of December 31, 2019, none of the contingent market conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met. On or after January 1, 2020, the 2020 Convertible Senior Notes are convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes are convertible at a current conversion rate of 6.4102 shares of Whiting’s common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. The Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company’s intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. At maturity, the Company must settle all outstanding 2020 Convertible Senior Notes in cash. The Company’s business plan includes the intent to settle the outstanding 2020 Convertible Senior Notes using borrowings under its credit agreement. Accordingly, the outstanding balance has been classified as long-term debt in the consolidated balance sheet as of December 31, 2019.

Upon issuance, the Company separately accounted for the liability and equity components of the 2020 Convertible Senior Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2020 Convertible Senior Notes and the estimated fair value of the liability component was recorded as a debt discount and is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.6% per annum. The fair value of the liability component of the 2020 Convertible Senior Notes as of the issuance date was estimated at $1.0 billion, resulting in a debt discount at inception of $238 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2020 Convertible Senior Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital within shareholders' equity, and will not be remeasured as long as it continues to meet the conditions for equity classification.

Transaction costs related to the 2020 Convertible Senior Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component were recorded as a reduction to the carrying value of long-term debt on the consolidated balance sheet and are being amortized to interest expense over the term of the notes using the effective interest method. Issuance costs attributable to the equity component were recorded as a charge to additional paid-in capital within shareholders' equity.

The 2020 Convertible Senior Notes consisted of the following at December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	2018
Liability component		
Principal	$ 262,075	$ 562,075
Less: unamortized note discount	(2,829)	(29,504)
Less: unamortized debt issuance costs	(220)	(2,340)
Net carrying value	$ 259,026	$ 530,231
Equity component (1)	$ 128,452	$ 136,522

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $50 million of deferred taxes as of December 31, 2019 and 2018.

Interest expense recognized on the 2020 Convertible Senior Notes related to the stated interest rate and amortization of the debt discount totaled $26 million, $29 million and $28 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Security and Guarantees

The Senior Notes and the 2020 Convertible Senior Notes are unsecured obligations of Whiting Petroleum Corporation and these unsecured obligations are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement.

The Company's obligations under the Senior Notes and the 2020 Convertible Senior Notes are guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas, Whiting US Holding Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (the "Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. Any subsidiaries other than these Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

6. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws and the terms of the Company's lease agreements. The current portions as of December 31, 2019 and 2018 were $4 million and have been included in accrued liabilities and other in the consolidated balance sheets. The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	2018
Asset retirement obligation at January 1	$ 135,834	$ 134,237
Additional liability incurred	2,097	11,981
Revisions to estimated cash flows	(10,945)	(17,197)
Accretion expense	11,602	11,405
Obligations on sold properties	(2,078)	(676)
Liabilities settled	(1,617)	(3,916)
Asset retirement obligation at December 31	$ 134,893	$ 135,834

7. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features which are required to be bifurcated and accounted for separately as derivatives.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. Whiting primarily enters into derivative contracts such as crude oil collars, swaps and options, as well as sales and delivery contracts, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility, thereby ensuring adequate funding for the Company's capital programs and facilitating the management of returns on drilling programs and acquisitions. The Company does not enter into derivative contracts for speculative or trading purposes.

Crude Oil Collars, Swaps and Options. Collars are designed to establish floor and ceiling prices on anticipated future oil or gas production, while swaps and options establish a fixed price for anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements.

The table below details the Company's collar, swap and option derivatives entered into to hedge forecasted crude oil production revenues as of December 31, 2019.

					Weighted Average Prices			
Commodity	Settlement Period	Index	Derivative Instrument	Contracted Crude Oil Volumes (Bbl)(1)	Swap Price	Sub-Floor	Floor	Ceiling
Crude Oil	2020	NYMEX WTI	Fixed Price Swaps	4,883,000	$57.57	-	-	-
Crude Oil	2020	NYMEX WTI	Two-way Collars	1,648,000	-	-	$54.33	$61.77
Crude Oil	2020	NYMEX WTI	Three-way Collars (2)	3,658,000	-	$43.50	$54.00	$63.63
Crude Oil	2021	NYMEX WTI	Three-way Collars (2)	1,095,000	-	$42.50	$52.50	$59.08
Crude Oil	2021	NYMEX WTI	Call Option (3)	365,000	-	-	-	$65.00
			Total	11,649,000				

(1) Subsequent to December 31, 2019, the Company entered into additional two-way collars for 1,373,000 Bbl of crude oil volumes for the remainder of 2020 and additional three-way collars for 730,000 Bbl of crude oil volumes for 2021.

(2) The Company is contracted to pay deferred premiums related to certain three-way collars at each settlement date. The weighted average premium for all three-way collars was $0.56 per Bbl as of December 31, 2019.

(3) This derivative instrument is a sold call option.

Crude Oil Sales and Delivery Contract. The Company had a long-term crude oil sales and delivery contract for oil volumes produced from its Redtail field in Colorado. Whiting determined that this contract would not qualify for the "normal purchase normal sale" exclusion and therefore reflected the contract at fair value in the consolidated financial statements prior to settlement. On February 1, 2018, Whiting paid $61 million to the counterparty to settle all future minimum volume commitments under this agreement. Accordingly, this crude oil sales and delivery contract was fully terminated and the fair value of the corresponding derivative was therefore zero as of that date.

Embedded Derivatives—In July 2016, the Company entered into a purchase and sale agreement with the buyer of its North Ward Estes Properties, whereby the buyer agreed to pay Whiting additional proceeds of $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million. The Company determined that this NYMEX-linked contingent payment was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at its estimated fair value in the consolidated financial statements. On July 19, 2017, the buyer paid $35 million to Whiting to settle this NYMEX-linked contingent payment, and accordingly, the embedded derivative's fair value was zero as of December 31, 2019 and 2018.

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion or other derivative scope exceptions. The following table summarizes the effects of derivative instruments on the consolidated statements of operations for the years ended December 31, 2019, 2018 and 2017 (in thousands):

Not Designated as ASC 815 Hedges	Statement of Operations Classification	Loss Recognized in Income Year Ended December 31, 2019	2018	2017
Commodity contracts	Derivative loss, net	$ 53,769	$ 17,170	$ 104,138
Embedded derivatives	Loss on sale of properties	-	-	18,709
Total		$ 53,769	$ 17,170	$ 122,847

Offsetting of Derivative Assets and Liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all the Company's derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2019 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets				
Commodity contracts - current	Derivative assets	$ 75,654	$ (74,768)	$ 886
Commodity contracts - non-current	Other long-term assets	5,648	(5,648)	-
Total derivative assets		$ 81,302	$ (80,416)	$ 886
Derivative liabilities				
Commodity contracts - current	Accrued liabilities and other	$ 85,053	$ (74,768)	$ 10,285
Commodity contracts - non-current	Other long-term liabilities	6,534	(5,648)	886
Total derivative liabilities		$ 91,587	$ (80,416)	$ 11,171

Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2018 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets				
Commodity contracts - current	Derivative assets	$ 69,735	$ (1,393)	$ 68,342
Total derivative assets		$ 69,735	$ (1,393)	$ 68,342
Derivative liabilities				
Commodity contracts - current	Accrued liabilities and other	$ 1,393	$ (1,393)	$ -
Total derivative liabilities		$ 1,393	$ (1,393)	$ -

(1) Because counterparties to the Company's financial derivative contracts subject to master netting arrangements are lenders under Whiting Oil and Gas' credit agreement, which eliminates its need to post or receive collateral associated with its derivative positions, columns for cash collateral pledged or received have not been presented in these tables.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting's bank debt, which eliminates the potential need to post collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

8. FAIR VALUE MEASUREMENTS

The Company follows FASB ASC Topic 820 – *Fair Value Measurement and Disclosure* which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

Cash, cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates.

The Company's senior notes are recorded at cost and the convertible senior notes are recorded at fair value at the date of issuance. The following table summarizes the fair values and carrying values of these instruments as of December 31, 2019 and 2018 (in thousands):

	December 31, 2019		December 31, 2018	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
1.25% Convertible Senior Notes due 2020	$ 260,214	$ 259,026	$ 531,161	$ 530,231
5.75% Senior Notes due 2021	732,995	772,080	829,929	870,545
6.25% Senior Notes due 2023	343,989	405,392	375,632	404,659
6.625% Senior Notes due 2026	681,250	988,387	865,000	986,886
Total	$ 2,018,448	$ 2,424,885	$ 2,601,722	$ 2,792,321

(1) Fair values are based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

(2) Carrying values are presented net of unamortized debt issuance costs and debt discounts or premiums.

The Company's derivative financial instruments are recorded at fair value and include a measure of the Company's own nonperformance risk or that of its counterparty, as appropriate. The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2019 and 2018, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2019
Financial Assets				
Commodity derivatives – current	$ -	$ 886	$ -	$ 886
Total financial assets	$ -	$ 886	$ -	$ 886
Financial Liabilities				
Commodity derivatives – current	$ -	$ 10,285	$ -	$ 10,285
Commodity derivatives – non-current	-	886	-	886
Total financial liabilities	$ -	$ 11,171	$ -	$ 11,171

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2018
Financial Assets				
Commodity derivatives – current	$ -	$ 68,342	$ -	$ 68,342
Total financial assets	$ -	$ 68,342	$ -	$ 68,342

The following methods and assumptions were used to estimate the fair values of the Company's financial assets and liabilities that are measured on a recurring basis:

Commodity Derivatives. Commodity derivative instruments consist mainly of collars, swaps and options for crude oil. The Company's collars, swaps and options are valued based on an income approach. Both the option and swap models consider various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

In addition, the Company had a long-term crude oil sales and delivery contract, whereby it had committed to deliver certain fixed volumes of crude oil produced from its Redtail field in Colorado. Whiting determined that the contract did not meet the "normal purchase normal sale" exclusion, and therefore reflected this contract at fair value in its consolidated financial statements prior to settlement. This commodity derivative was valued based on a probability-weighted income approach which considered various assumptions, including quoted spot prices for commodities, market differentials for crude oil, U.S. Treasury rates and either the

Company's or the counterparty's nonperformance risk, as appropriate. The assumptions used in the valuation of the crude oil sales and delivery contract included certain market differential metrics that were unobservable during the term of the contract. Such unobservable inputs were significant to the contract valuation methodology, and the contract's fair value was therefore designated as Level 3 within the valuation hierarchy. On February 1, 2018, Whiting paid $61 million to the counterparty to settle all future minimum volume commitments under this agreement. Accordingly, this derivative was settled in its entirety as of that date.

Level 3 Fair Value Measurements—The Company did not have any amounts designated as Level 3 in the valuation hierarchy as of and for the year ended December 31, 2019. The following table presents a reconciliation of changes in the fair value of financial liabilities designated as Level 3 in the valuation hierarchy for the year ended December 31, 2018 (in thousands):

	Year Ended December 31, 2018
Fair value liability, beginning of period	$ (63,278)
Unrealized gains on commodity derivative contracts included in earnings (1)	2,242
Settlement of commodity derivative contracts	61,036
Transfers into (out of) Level 3	-
Fair value liability, end of period	$ -

(1) Included in derivative loss, net in the consolidated statements of operations.

Non-recurring Fair Value Measurements—The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company did not recognize any impairment write-downs with respect to its proved property during the years ended December 31, 2019 and 2018. The following table presents information about the Company's non-financial assets measured at fair value on a non-recurring basis for the year ended December 31, 2017, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Net Carrying Value as of December 31, 2017	Fair Value Measurements Using			Loss (Before Tax) Year Ended December 31, 2017
		Level 1	Level 2	Level 3	
Proved property (1)	$ 389,390	$ -	$ -	$ 389,390	$ 834,950

(1) During the fourth quarter of 2017, proved oil and gas properties at the Redtail field in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado, with a previous carrying amount of $1.2 billion were written down to their fair value as of December 31, 2017 of $389 million, resulting in a non-cash impairment charge of $835 million which was recorded within exploration and impairment expense.

The following methods and assumptions were used to estimate the fair values of the non-financial assets in the table above:

Proved Property Impairments. The Company tests proved property for impairment whenever events or changes in circumstances indicate that the fair value of these assets may be reduced below their carrying value. Based on well performance results in the DJ Basin, the Company reduced its reserves at its Redtail field during the fourth quarter of 2017, and performed a proved property impairment test as of December 31, 2017. The fair value was ascribed using income approach analyses based on the net discounted future cash flows from the producing property and related assets. The discounted cash flows were based on management's expectations for the future. Unobservable inputs included estimates of future oil and gas production from the Company's reserve reports, commodity prices based on sales contract terms or forward price curves (adjusted for basis differentials), operating and development costs, and a discount rate based on the Company's weighted-average cost of capital (all of which were designated as Level 3 inputs within the fair value hierarchy). The impairment test indicated that a proved property impairment had occurred, and the Company therefore recorded a non-cash impairment charge to reduce the carrying value of the impaired property to its fair value at December 31, 2017.

9. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

Common Stock

Reverse Stock Split. On November 8, 2017 and following approval by the Company's stockholders of an amendment to its certificate of incorporation to effect a reverse stock split, the Company's Board of Directors approved a reverse stock split of Whiting's common stock at a ratio of one-for-four and a reduction in the number of authorized shares of the Company's common stock from 600,000,000 shares to 225,000,000. Whiting's common stock began trading on a split-adjusted basis on November 9, 2017 upon opening of the New York Stock Exchange trading day. All share and per share amounts in these consolidated financial statements and related notes for periods prior to November 2017 have been retroactively adjusted to reflect the reverse stock split.

Noncontrolling Interest—The Company's noncontrolling interest represented an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC ("SWR"). During the third quarter of 2017, the third party's ownership interest in SWR was assigned back to SWR. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Year Ended December 31, 2017
Balance at beginning of period	$ 7,962
Net loss	(14)
Conveyance of ownership interest	(7,948)
Balance at end of period	$ -

10. REVENUE RECOGNITION

The Company recognizes revenue in accordance with FASB ASC Topic 606 – *Revenue from Contracts with Customers* ("ASC 606"). Revenue is recognized at the point in time at which the Company's performance obligations under its commodity sales contracts are satisfied and control of the commodity is transferred to the customer. The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as transportation, gathering, compression and other, and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered. The table below presents the disaggregation of revenue by product type for the years ended December 31, 2019 and 2018 (in thousands):

	December 31, 2019	December 31, 2018
OPERATING REVENUES		
Oil sales	$ 1,492,218	$ 1,850,052
NGL and natural gas sales	80,027	231,362
Oil, NGL and natural gas sales	$ 1,572,245	$ 2,081,414

Whiting receives payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in accounts receivable trade, net in the consolidated balance sheets. As of December 31, 2019 and 2018, such receivable balances were $161 million and $165 million, respectively. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained.

The Company has elected to utilize the practical expedient in ASC 606 that states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's contracts, each monthly delivery of product represents a separate performance obligation, therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

11. STOCK-BASED COMPENSATION

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2013 Equity Incentive Plan, as amended and restated (the "2013 Equity Plan"), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "2003 Equity Plan") and originally granted the authority to issue 1,325,000 shares of the Company's common stock. During 2016, shareholders approved an amendment to the 2013 Equity Plan granting the authority to issue an additional 1,375,000 shares of the Company's common stock. In May 2019, shareholders approved an additional amendment to the 2013 Equity Plan granting the authority to issue an additional 3,000,000 shares of the Company's common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan was terminated. The 2003 Equity Plan continues to govern awards that were outstanding as of the date of its termination, which awards remain in effect pursuant to their terms. Any shares netted or forfeited under the 2003 Equity Plan and any shares forfeited under the 2013 Equity Plan will be available for future issuance under the 2013 Equity Plan. However, shares netted for tax withholding under the 2013 Equity Plan will be cancelled and will not be available for future issuance. Under the amended and restated 2013 Equity Plan, during any calendar year, no officer or other key employee participant may be granted options or stock appreciation rights for more than 500,000 shares of common stock or more than 500,000 shares of restricted stock ("RSAs"), restricted stock units ("RSUs"), performance shares ("PSAs") or performance share units ("PSUs"), the value of which is based on the fair market value of a share of common stock. In addition, no non-employee director participant may be granted during any calendar year options or stock appreciation rights for more than 25,000 shares of common stock, or more than 25,000 shares of RSAs or RSUs. As of December 31, 2019, 3,698,933 shares of common stock remained available for grant under the 2013 Equity Plan.

The Company grants service-based RSAs and RSUs to executive officers and employees, which generally vest ratably over a three-year service period. The Company also grants service-based RSAs to directors, which generally vest over a one-year service period. In addition, the Company grants PSAs and PSUs to executive officers that are subject to market-based vesting criteria, which generally vest over a three-year service period. The Company accounts for forfeitures of awards granted under these plans as they occur in determining compensation expense. The Company recognizes compensation expense for awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense for share-settled awards is not reversed if vesting does not actually occur.

During 2019, 2018 and 2017, 467,055, 249,983 and 538,194 shares, respectively, of service-based RSAs and RSUs were granted to employees, executive officers and directors under the 2013 Equity Plan. The Company determines compensation expense for these share-settled awards using their fair value at the grant date, which is based on the closing bid price of the Company's common stock on such date. The weighted average grant date fair value of service-based RSAs and RSUs was $24.65 per share, $32.34 per share and $40.66 per share for the years ended December 31, 2019, 2018, and 2017, respectively.

During 2019 and 2018, 774,665 and 308,432 shares, respectively, of service-based RSUs were granted to employees under the 2013 Equity Plan. These awards will be settled in cash and are recorded as a liability in the consolidated balance sheets. The Company determines compensation expense for cash-settled RSUs using the fair value at the end of each reporting period, which is based on the closing bid price of the Company's common stock on such date.

During 2019 and 2018, 347,493 and 230,932 shares, respectively, of PSAs and PSUs subject to certain market-based vesting criteria were granted to executive officers under the 2013 Equity Plan. The market-based awards cliff vest on the third anniversary of the grant date, and the number of shares that will vest at the end of that three-year performance period is determined based on the rank of Whiting's cumulative stockholder return compared to the stockholder return of a peer group of companies on each anniversary of the grant date over the three-year performance period. The number of awards earned could range from zero up to two times the number of shares initially granted. However, awards earned up to the target shares granted (or 100%) will be settled in shares, while awards earned in excess of the target shares granted will be settled in cash. The cash-settled component of such awards is recorded as a liability in the consolidated balance sheets and will be remeasured at fair value using a Monte Carlo valuation model at the end of each reporting period.

During 2017, 168,466 PSAs subject to certain market-based vesting criteria were granted to executive officers under the 2013 Equity Plan. These market-based awards cliff vest on the third anniversary of the grant date, and the number of shares that will vest at the end of that three-year performance period is determined based on the rank of Whiting's cumulative stockholder return compared to the stockholder return of a peer group of companies over the same three-year period. The number of shares earned could range from zero up to two times the number of shares initially granted and will be settled entirely in shares.

For awards subject to market conditions, the grant date fair value is estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of Whiting's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing these market-based awards were as follows:

	2019	2018	2017
Number of simulations	2,500,000	2,500,000	2,500,000
Expected volatility	72.95%	72.80%	82.44%
Risk-free interest rate	2.60%	2.12%	1.52%
Dividend yield	—	—	—

The weighted average grant date fair value of the market-based awards that will be settled in shares as determined by the Monte Carlo valuation model was $25.97 per share, $27.28 per share and $63.04 per share in 2019, 2018 and 2017, respectively.

The following table shows a summary of the Company's service-based and market-based awards activity for the year ended December 31, 2019:

	Number of Awards		Weighted Average
	Service-Based RSAs & RSUs	Market-Based PSAs & PSUs	Grant Date Fair Value
Nonvested awards, January 1	554,527	503,696	$ 34.94
Granted	467,055	347,493	24.61
Vested	(383,908)	(98,581)	32.15
Forfeited	(170,172)	(304,221)	32.88
Nonvested awards, December 31	467,502	448,387	$ 28.28

As of December 31, 2019, there was $13 million of total unrecognized compensation cost related to unvested awards granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.0 years. For the years ended December 31, 2019, 2018 and 2017, the total fair value of the Company's service-based and market-based awards vested was $12 million, $16 million and $15 million, respectively.

Stock Options—Stock options may be granted to certain executive officers of the Company with exercise prices equal to the closing market price of the Company's common stock on the grant date. There were no stock options granted under the 2013 Equity Plan during 2019, 2018 or 2017. The Company's stock options vest ratably over a three-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The following table shows a summary of the Company's stock options outstanding as of December 31, 2019 as well as activity during the year then ended:

	Number of Options	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value (in thousands)	Weighted Average Remaining Contractual Term (in years)
Options outstanding at January 1	49,230	$ 195.92		
Granted	-	-		
Exercised	-	-	$ -	
Forfeited or expired	(6,270)	216.78		
Options outstanding at December 31	42,960	$ 192.88	$ -	2.2
Options vested at December 31	42,960	$ 192.88	$ -	2.2
Options exercisable at December 31	42,960	$ 192.88	$ -	2.2

There was no unrecognized compensation cost related to unvested stock option awards as of December 31, 2019. For the year ended December 31, 2018, the aggregate intrinsic value of stock options exercised was $0.1 million. There were no stock options exercised during the years ended December 31, 2019 or 2017.

Total stock-based compensation expense was $8 million, $18 million and $22 million for the years ended December 31, 2019, 2018 and 2017, respectively.

12. INCOME TAXES

Income tax expense (benefit) consists of the following (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Current income tax expense (benefit)			
Federal	$ -	$ -	$ (7,305)
State	-	-	14
Total current income tax benefit	-	-	(7,291)
Deferred income tax expense (benefit)			
Federal	2,140	(10,960)	(398,686)
State	(3,513)	12,333	(77,002)
Foreign	73,593	-	-
Total deferred income tax expense (benefit)	72,220	1,373	(475,688)
Total	$ 72,220	$ 1,373	$ (482,979)

Income tax expense (benefit) differed from amounts that would result from applying the U.S. statutory income tax rate (21% for the years ended December 31, 2019 and 2018 and 35% for the year ended December 31, 2017) to income before income taxes as follows (in thousands):

	Year Ended December 31,		
	2019	2018	2017
U.S. statutory income tax expense (benefit)	$ (35,479)	$ 72,211	$ (602,219)
State income taxes, net of federal benefit	(8,288)	14,324	(39,557)
Foreign tax expense	(147)	-	-
Valuation allowance	39,672	(87,774)	120,880
Federal tax reform	-	-	(42,033)
Impairment charge after enactment of federal tax reform	-	-	114,293
IRC Section 382 limitation	-	-	(45,899)
Market-based equity awards	910	2,215	7,003
Outside basis difference recognition	73,740	-	-
Other	1,812	397	4,553
Total	$ 72,220	$ 1,373	$ (482,979)

The principal components of the Company's deferred income tax assets and liabilities at December 31, 2019 and 2018 were as follows (in thousands):

	Year Ended December 31,	
	2019	2018
Deferred income tax assets		
Net operating loss carryforward	$ 944,709	$ 873,646
Derivative instruments	2,451	-
Asset retirement obligations	32,152	32,546
Restricted stock compensation	2,033	5,603
EOR credit carryforwards	7,946	7,946
Lease obligations	14,463	-
Other	12,847	10,777
Total deferred income tax assets	1,016,601	930,518
Less valuation allowance	(188,281)	(152,035)
Net deferred income tax assets	828,320	778,483
Deferred income tax liabilities		
Oil and gas properties	805,989	740,933
Trust distributions	10,517	15,479
Lease assets	10,993	-
Derivative instruments	-	16,375
Discount on convertible senior notes	674	7,069
Foreign outside basis difference	73,740	-
Total deferred income tax liabilities	901,913	779,856
Total net deferred income tax liabilities	$ 73,593	$ 1,373

The Company's July 1, 2016 note exchange transactions triggered an ownership shift within the meaning of Section 382 of the Internal Revenue Code ("IRC") due to the "deemed share issuance" that resulted from the note exchanges. The ownership shift will limit Whiting's usage of certain of its net operating losses ("NOLs") and tax credits in the future. Accordingly, the Company recognized valuation allowances on its deferred tax assets totaling $259 million. In the third quarter of 2017 there was a partial release of this valuation allowance in the amount of $41 million associated with built-on gains on the sale of the FBIR Assets.

As of December 31, 2019, the Company had federal NOL carryforwards of $3.4 billion, which is net of the IRC Section 382 limitation. The Company also has various state NOL carryforwards. The determination of the state NOL carryforwards is dependent upon apportionment percentages and state laws that can change from year to year and that can thereby impact the amount of such carryforwards. If unutilized, the majority of the federal NOLs will expire between 2023 and 2037 and the state NOLs will expire between 2020 and 2037. Any federal NOLs generated in 2018 or subsequent do not expire.

EOR credits are a credit against federal income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed enhanced tertiary recovery methods. As of December 31, 2019, the Company had recognized aggregate EOR credits of $8 million. As a result of the IRC Section 382 limitation in July 2016, the Company recorded a full valuation allowance on these credits.

On December 22, 2017, Congress passed the Tax Cuts and Jobs Act (the "TCJA"). The legislation significantly changed the U.S. corporate tax law by, among other things, lowering the U.S. corporate income tax rate from 35% to 21% beginning in January 2018, implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries. FASB ASC Topic 740 – *Income Taxes* requires companies to recognize the impact of the changes in tax law in the period of enactment. The SEC subsequently issued Staff Accounting Bulletin No. 118, which allowed registrants to record provisional amounts during a one-year "measurement period" similar to that used to account for business combinations. The Company did not recognize any measurement period adjustments during 2018 and its accounting for the TCJA was complete as of December 31, 2018.

Amounts recorded during the year ended December 31, 2017 related to the TCJA principally relate to the reduction in the U.S. corporate income tax rate to 21%, which resulted in (i) income tax expense of $51 million from the revaluation of the Company's deferred tax assets and liabilities as of the date of enactment and (ii) an income tax benefit totaling $93 million related to a reduction in the Company's existing valuation allowances.

Other elements of the TCJA that did not have an impact on the Company’s financial statements upon enactment of the TCJA, but may impact the Company’s income taxes in future periods include: (i) IRC Section 168(k) first-year optional bonus depreciation, (ii) repeal of the corporate alternative minimum tax, (iii) limitation on the usage of NOLs generated after 2017 to 80% of taxable income, (iv) additional limitations on certain meals and entertainment expenses, (v) repeal of the deduction for income attributable to domestic production activities, (vi) like-kind exchange limitations for property other than real property, (vii) ability to capitalize and amortize intangible drilling costs under IRC Section 59(e), and (viii) interest deduction limitations under IRC Section 163(j).

In assessing the realizability of deferred tax assets (“DTAs”), management considers whether it is more likely than not that some portion, or all, of the Company’s DTAs will not be realized. In making such determination, the Company considers all available positive and negative evidence, including future reversals of temporary differences, tax-planning strategies and projected future taxable income and results of operations. If the Company concludes that it is more likely than not that some portion, or all, of its DTAs will not be realized, the tax asset is reduced by a valuation allowance. At December 31, 2019, the Company had a valuation allowance totaling $188 million, comprised of $138 million of NOL carryforward limitations under Section 382 of the IRC, $8 million of EOR credits, which will expire between 2023 and 2025, $1 million of short-term capital loss carryforwards that are not expected to be realized and a $41 million general valuation allowance against the Company’s net U.S. deferred tax assets.

During the fourth quarter of 2019, the Company determined it no longer had the ability to indefinitely prevent the reversal of the outside basis difference related to Whiting Canadian Holding Company ULC, Whiting’s wholly owned subsidiary, which owns a portion of Whiting’s U.S. assets obtained through the acquisition of Kodiak Oil and Gas Corporation during 2014. Accordingly, the Company revised its assessment related to noncurrent Canadian deferred taxes pursuant to ASC 740-30-25-17 and recognized a $74 million deferred tax liability as well as the same amount of deferred income tax expense as of and for the year ended December 31, 2019 associated with the outside basis difference related to Whiting Canadian Holding Company ULC.

During 2018, the Company recorded an adjustment to its valuation allowance on DTAs totaling $30 million. At December 31, 2018, the Company had a valuation allowance totaling $152 million, comprised of $138 million of NOL carryforward limitations under Section 382 of the IRC, $8 million of EOR credits, which will expire between 2023 and 2025, $5 million of Canadian NOL carryforwards, which will expire between 2034 and 2035, and $1 million of short-term capital loss carryforwards that are not expected to be realized.

As of December 31, 2019 and 2018, the Company did not have any uncertain tax positions. For the years ended December 31, 2019, 2018 and 2017, the Company did not recognize any interest or penalties with respect to unrecognized tax benefits, nor did the Company have any such interest or penalties previously accrued. The Company believes that it is reasonably possible that no increases to unrecognized tax benefits will occur in the next twelve months.

The Company files income tax returns in the U.S. federal jurisdiction and in various states, each with varying statutes of limitations. The 2015 through 2019 tax years generally remain subject to examination by federal and state tax authorities. Additionally, the Company has Canadian income tax filings which remain subject to examination by the related tax authorities for the 2014 through 2019 tax years.

13. EARNINGS PER SHARE

The reconciliations between basic and diluted earnings (loss) per share are as follows (in thousands, except per share data):

	Year Ended December 31,		
	2019	2018	2017
Basic Earnings (Loss) Per Share			
Net income (loss) attributable to common shareholders	$ (241,166)	$ 342,494	$ (1,237,648)
Weighted average shares outstanding, basic	91,285	90,953	90,683
Earnings (loss) per common share, basic	$ (2.64)	$ 3.77	$ (13.65)
Diluted Earnings (Loss) Per Share			
Net income (loss) attributable to common shareholders	$ (241,166)	$ 342,494	$ (1,237,648)
Weighted average shares outstanding, basic	91,285	90,953	90,683
Service-based awards, market-based awards and stock options	-	916	-
Weighted average shares outstanding, diluted	91,285	91,869	90,683
Earnings (loss) per common share, diluted	$ (2.64)	$ 3.73	$ (13.65)

For the year ended December 31, 2019 the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 344,671 shares of service-based awards and 3,511 shares of market-based awards. In addition, the diluted earnings per share calculation for the year ended December 31, 2019 excludes the effect of 45,588 common shares for stock options that were out of the money as of December 31, 2019.

For the year ended December 31, 2018, the diluted earnings per share calculation excludes the effect of 100,708 common shares for stock options that were out of the money as of December 31, 2018.

For the year ended December 31, 2017, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 509,744 shares of service-based awards, 22,946 shares of market-based awards and 1,083 stock options. In addition, the diluted earnings per share calculation for the year ended December 31, 2017 excludes the effect of 123,775 common shares for stock options that were out-of-the-money and 345,071 shares of market-based awards that did not meet the market-based vesting criteria as of December 31, 2017.

Refer to the “Stock-Based Compensation” footnote for further information on the Company’s service-based awards, market-based awards and stock options.

As discussed in the “Long-Term Debt” footnote, the Company has the option to settle conversions of the 2020 Convertible Senior Notes with cash, shares of common stock or any combination thereof. Based on the current conversion price, the entire outstanding principal amount of the 2020 Convertible Senior Notes as of December 31, 2019 would be convertible into approximately 1.7 million shares of the Company’s common stock. However, the Company’s intent is to settle the principal amount of the notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (the “conversion spread”) is considered in the diluted earnings per share computation under the treasury stock method. As of December 31, 2019, 2018 and 2017, the conversion value did not exceed the principal amount of the notes. Accordingly, there was no impact to diluted earnings per share or the related disclosures for those periods.

14. COMMITMENTS AND CONTINGENCIES

The table below shows the Company's minimum future payments due by period under unconditional purchase obligations as of December 31, 2019 (in thousands):

Year ending December 31,	Pipeline Transportation Agreements
2020	$ 2,189
2021	2,189
2022	2,189
2023	2,189
2024	547
Total payments	$ 9,303

Pipeline Transportation Agreements—The Company has two effective agreements through 2024 with various third parties to facilitate the delivery of its produced oil, gas and NGLs to market. Under one of these contracts, the Company has committed to pay fixed monthly reservation fees on dedicated pipelines for natural gas and NGL transportation capacity, plus additional variable charges based on actual transportation volumes. These fixed monthly reservation fees totaling approximately $9 million have been included in the table above.

The remaining contract contains a commitment to transport a minimum volume of crude oil or else pay for any deficiencies at a price stipulated in the contract. Although minimum annual quantities are specified in the agreement, the actual oil volumes transported and their corresponding unit prices are variable over the term of the contract. As a result, the future minimum payments for each of the five succeeding fiscal years are not fixed and determinable and are not therefore included in the table above. As of December 31, 2019, the Company estimated the minimum future commitments under this transportation agreement to approximate $9 million through 2022.

During 2019, 2018 and 2017, the cost of transportation of crude oil, natural gas and NGLs under these contracts amounted to $2 million, $2 million and $2 million, respectively.

Purchase Contracts—The Company's purchase obligation consists of a take-or-pay arrangement to buy volumes of water for use in the fracture stimulation process. Under the terms of the agreement, the Company is obligated to purchase a minimum volume of water or else pay for any deficiencies at the price stipulated in the contract. Although minimum daily quantities are specified in the agreement, the actual water volumes purchased and their corresponding unit prices are variable over the term of the contract. As a result, the future minimum payments for each of the five succeeding fiscal years are not fixed and determinable and are not therefore included in the table above. As of December 31, 2019, the Company estimated the minimum future commitments under this purchase agreement to approximate $8 million through 2020.

As a result of the Company's reduced development operations in its Redtail field, Whiting has made and expects to make periodic deficiency payments under this purchase contract during the remaining term, which expires in 2020. During 2019, 2018 and 2017, purchases of water under the Company's take-or-pay arrangement amounted to $8 million, $8 million and $22 million, respectively, which included $8 million and $2 million of deficiency payments for the years ended December 31, 2019 and 2018, respectively, and insignificant deficiency payments for the year ended December 31, 2017.

Water Disposal Agreement—The Company has a water disposal agreement expiring in 2024 under which it has contracted for the transportation and disposal of the produced water from its Redtail field. Under the terms of the agreement, the Company is obligated to provide a minimum volume of produced water or else pay for any deficiencies at the price stipulated in the contract. Although minimum monthly quantities are specified in the agreement, the actual water volumes disposed of and their corresponding unit prices are variable over the term of the contract. As a result, the future minimum payments for each of the five succeeding fiscal years are not fixed and determinable and are therefore not included in the table above. As of December 31, 2019, the Company estimated the minimum future commitments under this disposal agreement to approximate $83 million through 2024. As a result of the Company's reduced development operations at its Redtail field, Whiting has made and expects to make periodic deficiency payments under this contract. During 2019, 2018 and 2017, transportation and disposal of produced water amounted to $20 million, $19 million and $16 million, respectively, which includes $14 million, $5 million and $4 million of deficiency payments, respectively.

Delivery Commitments**—**The Company has three physical delivery contracts which require the Company to deliver fixed volumes of crude oil. One of these delivery commitments became effective on June 1, 2017 upon completion of the Dakota Access Pipeline, and it is tied to crude oil production from Whiting's Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, Whiting has committed to deliver 15 MBbl/d for a term of seven years. The Company believes its production and reserves at the Sanish field are sufficient to fulfill this delivery commitment, and therefore expects to avoid any payments for deficiencies under this contract.

The second delivery contract is tied to oil production in the Williston Basin. The effective date of this contract is contingent upon the completion of certain related pipelines, which are currently expected to be brought online in 2021. Under the terms of the agreement, Whiting has committed to deliver 10 MBbl/d for a term of seven years. The Company believes its production and reserves in the Williston Basin are sufficient to fulfill this delivery commitment, and therefore expects to avoid any payments for deficiencies under this contract.

The third delivery contract is tied to crude oil production at Whiting's Redtail field in Weld County, Colorado. As of December 31, 2019, this contract contains remaining delivery commitments of 4.1 MMBbl of crude oil through the end of the contract's term in April 2020. The Company has determined that it is not probable that future oil production from its Redtail field will be sufficient to meet the minimum volume requirements specified in these physical delivery contracts, and as a result, the Company expects to make periodic deficiency payments for any shortfalls in delivering the minimum committed volumes.

During 2019, 2018 and 2017, total deficiency payments under these contracts, as well as a previous Redtail contract that was terminated in February 2018, amounted to $64 million, $39 million and $66 million, respectively. The Company recognizes any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred. The table above does not include any such deficiency payments that may be incurred under the Company's physical delivery contracts, since it cannot be predicted with accuracy the amount and timing of any such penalties incurred.

Litigation**—**The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the ordinary course of business. The Company accrues a loss contingency for these lawsuits and claims when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is the opinion of the Company's management that the loss for any litigation matters and claims that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on its consolidated financial position, cash flows or results of operations. The Company is involved in litigation related to a payment arrangement with a third party which currently claims damages up to $41 million, as well as court costs and interest, that is scheduled to go to trial in May 2020. Certain amounts have been accrued in accrued liabilities and other in the consolidated balance sheet as of December 31, 2019 and general and administrative expenses in the consolidated statement of operations for the year ended December 31, 2019 based on the determination that it is probable that a loss has been incurred and can be reasonably estimated.

15. CAPITALIZED EXPLORATORY WELL COSTS

Exploratory well costs that are incurred and expensed in the same annual period have not been included in the table below. The net changes in capitalized exploratory well costs were as follows (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Beginning balance at January 1	$ -	$ 13,894	$ -
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	10,831	13,894
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	-	(24,725)	-
Ending balance at December 31	$ -	$ -	$ 13,894

At December 31, 2019, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

16. RESTRUCTURING

On July 31, 2019, the Company executed a workforce reduction as part of an organizational redesign and cost reduction strategy to better align its business with the current operating environment and drive long-term value. In connection with these activities, the Company incurred $8 million in net restructuring costs associated with one-time employee termination benefits. These restructuring costs are included in general and administrative expenses in the consolidated statements of operations.

17. SUBSEQUENT EVENTS

On January 9, 2020, the Company completed the divestiture of its interests in 30 non-operated, producing oil and gas wells and related undeveloped acreage located in McKenzie County, North Dakota for aggregate sales proceeds of $25 million (before closing adjustments).

SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Oil and Gas Producing Activities

Net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,	
	2019	**2018**
Proved oil and gas properties	$ 12,549,395	$ 11,911,977
Unproved oil and gas properties	262,612	283,682
Accumulated depletion	(5,656,929)	(4,937,579)
Oil and gas properties, net	$ 7,155,078	$ 7,258,080

The Company's oil and gas activities for 2019, 2018 and 2017 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,		
	2019	**2018**	**2017**
Development [(1)]	$ 763,395	$ 803,143	$ 799,462
Proved property acquisition	-	105,519	4,075
Unproved property acquisition	6,281	34,671	17,629
Exploration	36,872	32,911	50,218
Total	$ 806,548	$ 976,244	$ 871,384

(1) Development costs include non-cash downward adjustments to oil and gas properties of $9 million, $5 million and $45 million for 2019, 2018 and 2017, respectively, which relate to estimated future plugging and abandonment costs of the Company's oil and gas wells.

Oil and Gas Reserve Quantities

For all years presented, the Company's independent petroleum engineers independently estimated all of the proved reserve quantities included in this Annual Report on Form 10-K. In connection with the external petroleum engineers performing their independent reserve estimations, Whiting furnishes them with the following information for their review: (i) technical support data, (ii) technical analysis of geologic and engineering support information, (iii) economic and production data, and (iv) the Company's well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of the Company's estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2019. Proved reserve estimates included herein conform to the definitions prescribed by the SEC. Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

As of December 31, 2019, all of the Company's oil and gas reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil and gas reserves for the years ended December 31, 2017, 2018 and 2019 are as follows:

	Oil (MBbl)	NGLs (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves				
Balance—January 1, 2017	394,767	101,493	715,659	615,537
Extensions and discoveries	30,076	14,512	82,391	58,320
Sales of minerals in place	(42,137)	(5,263)	(18,116)	(50,419)
Purchases of minerals in place	157	29	283	233
Production	(29,261)	(6,978)	(41,261)	(43,115)
Revisions to previous estimates	(16,019)	35,156	107,521	37,056
Balance—December 31, 2017	337,583	138,949	846,477	617,612
Extensions and discoveries	17,470	8,552	48,969	34,184
Purchases of minerals in place	20,293	1,386	24,003	25,679
Production	(31,517)	(7,394)	(46,810)	(46,712)
Revisions to previous estimates	(56,865)	(30,209)	(141,555)	(110,668)
Balance—December 31, 2018	286,964	111,284	731,084	520,095
Extensions and discoveries	20,103	6,056	46,808	33,960
Sales of minerals in place	(3,175)	(855)	(5,253)	(4,906)
Production	(29,811)	(7,596)	(50,483)	(45,820)
Revisions to previous estimates	(5,828)	(15,048)	17,886	(17,894)
Balance—December 31, 2019	268,253	93,841	740,042	485,435
Proved developed reserves				
December 31, 2016	183,165	51,888	337,860	291,363
December 31, 2017	179,829	76,957	473,829	335,758
December 31, 2018	194,869	82,725	529,154	365,786
December 31, 2019	190,725	72,102	576,213	358,863
Proved undeveloped reserves				
December 31, 2016	211,602	49,605	377,799	324,174
December 31, 2017	157,754	61,992	372,648	281,854
December 31, 2018	92,095	28,559	201,930	154,309
December 31, 2019	77,528	21,739	163,829	126,572

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- *Extensions and discoveries.* In 2019, total extensions and discoveries of 34.0 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Sales of minerals in place.* Sales of minerals in place totaled 4.9 MMBOE during 2019 and were primarily attributable to the disposition of certain non-operated properties in North Dakota as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements.

- *Revisions to previous estimates.* In 2019, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 17.9 MMBOE. Included in this change were upward revisions of 48.0 MMBOE to proved undeveloped reserves primarily located in the Williston Basin in locations where we have significant development activity and past drilling success. Offsetting these upward revisions were: (i) 32.9 MMBOE of downward adjustments caused by lower crude oil, NGL and natural gas prices incorporated into our reserve estimates at December 31, 2019 as compared to December 31, 2018, (ii) 19.3 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance across our Northern and Central Rockies

assets and (iii) 13.7 MMBOE of proved undeveloped reserves no longer expected to be developed within five years from their initial recognition.

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

- *Extensions and discoveries.* In 2018, total extensions and discoveries of 34.2 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Purchases of minerals in place.* In 2018, total purchases of minerals in place of 25.7 MMBOE were primarily attributable to the acquisition of 117 producing oil and gas wells and undeveloped acreage in the Williston Basin, further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements, which increased the Company's proved reserves.

- *Revisions to previous estimates.* In 2018, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 110.7 MMBOE. Included in these revisions were 99.9 MMBOE of proved undeveloped reserves no longer expected to be developed within five years from their initial recognition. As a result of sustained lower crude oil prices in recent years, the Company has moved toward a more disciplined capital development program focused on the highest-return projects and the generation of free cash flow. This shift in strategy resulted in a change in the timing of the Company's development plans related to PUD reserves in certain areas. These revisions do not represent the elimination of recoverable hydrocarbons physically in place, however, as they may be developed in the future. In addition, there were 38.1 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance across the Company's Northern and Central Rockies assets and 27.3 MMBOE of upward adjustments caused by higher crude oil, NGL and natural gas prices incorporated into the Company's reserve estimates at December 31, 2018 as compared to December 31, 2017.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* In 2017, total extensions and discoveries of 58.3 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in this area as well as the PUD locations added as a result of drilling increased the Company's proved reserves.

- *Sales of minerals in place.* Sales of minerals in place totaled 50.4 MMBOE during 2017 and were primarily attributable to the disposition of the FBIR Assets as further described in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements.

- *Revisions to previous estimates.* In 2017, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 37.1 MMBOE. Included in these revisions were (i) 88.7 MMBOE of upward adjustments caused by higher crude oil, NGL and natural gas prices incorporated into the Company's reserve estimates at December 31, 2017 as compared to December 31, 2016 and (ii) 51.6 MMBOE of downward adjustments primarily attributable to reservoir analysis and well performance in the Redtail field.

Standardized Measure of Discounted Future Net Cash Flows

The Standardized Measure relating to proved oil and gas reserves and changes in the Standardized Measure relating to proved oil and natural gas reserves were prepared in accordance with the provisions of FASB ASC Topic 932, *Extractive Activities—Oil and Gas*. Future cash inflows as of December 31, 2019, 2018 and 2017 were computed by applying average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2019, 2018 and 2017, respectively) to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming the continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of

10% annually to derive the Standardized Measure. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

The Standardized Measure relating to proved oil and natural gas reserves is as follows (in thousands):

	December 31,		
	2019	2018	2017
Future cash flows	$ 14,700,974	$ 20,237,473	$ 19,635,532
Future production costs	(6,983,878)	(7,450,206)	(7,874,590)
Future development costs	(1,451,487)	(1,853,805)	(3,022,841)
Future income tax expense	(88,960)	(1,065,686)	(474,646)
Future net cash flows	6,176,649	9,867,776	8,263,455
10% annual discount for estimated timing of cash flows	(2,474,320)	(4,661,666)	(4,395,897)
Standardized measure of discounted future net cash flows	$ 3,702,329	$ 5,206,110	$ 3,867,558

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transactions were included in the computation, then undiscounted future cash inflows would have had no significant impact on undiscounted future cash inflows in 2019, 2018 and 2017.

The changes in the Standardized Measure relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Beginning of year	$ 5,206,110	$ 3,867,558	$ 2,698,086
Sale of oil and gas produced, net of production costs	(1,063,167)	(1,549,591)	(991,069)
Sales of minerals in place	(52,456)	-	(312,346)
Net changes in prices and production costs	(1,681,530)	1,800,523	994,749
Extensions, discoveries and improved recoveries	234,782	465,766	437,459
Previously estimated development costs incurred during the period	455,236	639,827	542,746
Changes in estimated future development costs	(12,964)	598,535	50,215
Purchases of minerals in place	-	349,896	1,748
Revisions of previous quantity estimates	(191,329)	(1,167,886)	277,967
Net change in income taxes	287,036	(185,274)	(101,806)
Accretion of discount	520,611	386,756	269,809
End of year	$ 3,702,329	$ 5,206,110	$ 3,867,558

Future net revenues included in the Standardized Measure relating to proved oil and natural gas reserves incorporate calculated weighted average sales prices (inclusive of adjustments for quality and location) in effect at December 31, 2019, 2018 and 2017 as follows:

	2019	2018	2017
Oil (per Bbl)	$ 50.89	$ 60.08	$ 47.16
NGLs (per Bbl)	$ 8.72	$ 18.58	$ 14.74
Natural Gas (per Mcf)	$ 0.31	$ 1.27	$ 1.97

QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2019 and 2018 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2019	**June 30, 2019**	**September 30, 2019**	**December 31, 2019**
Oil, NGL and natural gas sales	$ 389,489	$ 426,264	$ 375,891	$ 380,601
Gross profit	$ 69,283	$ 85,720	$ 33,150	$ 58,527
Net loss	$ (68,925)	$ (5,687)	$ (19,067)	$ (147,487)
Basic loss per share	$ (0.76)	$ (0.06)	$ (0.21)	$ (1.62)
Diluted loss per share	$ (0.76)	$ (0.06)	$ (0.21)	$ (1.62)

	Three Months Ended			
	March 31, 2018	**June 30, 2018**	**September 30, 2018**	**December 31, 2018**
Oil, NGL and natural gas sales	$ 515,083	$ 526,403	$ 566,695	$ 473,233
Gross profit	$ 197,293	$ 194,626	$ 232,168	$ 144,175
Net income	$ 15,012	$ 2,120	$ 121,400	$ 203,962
Basic earnings per share	$ 0.17	$ 0.02	$ 1.33	$ 2.24
Diluted earnings per share	$ 0.16	$ 0.02	$ 1.32	$ 2.22

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the year ended December 31, 2019. Based upon their evaluation of these disclosure controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of December 31, 2019 to ensure that information required to be disclosed by us in the reports that 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 Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. The management of Whiting Petroleum Corporation and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our 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 the inherent limitations of internal control over financial reporting, misstatements may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2019 using the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2019, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein on the following page.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2019 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation
Denver, Colorado

Opinion on Internal Control over Financial Reporting

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements as of and for the year ended December 31, 2019 of the Company and our report dated February 27, 2020 expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 27, 2020

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information included under the captions “Corporate Governance – Proposal 1 – Election of Directors”, “Corporate Governance – Board Committee Information – Audit Committee” and “Delinquent Section 16(a) Reports” in our definitive Proxy Statement for Whiting Petroleum Corporation’s 2020 Annual Meeting of Stockholders (the “Proxy Statement”) is incorporated herein by reference. Information with respect to our executive officers appears in Part I of this Annual Report on Form 10-K.

We have adopted the Whiting Petroleum Corporation Code of Business Conduct and Ethics that applies to our directors, our Chairman, President and Chief Executive Officer, our Chief Financial Officer, our Vice President and Controller and other persons performing similar functions. We have posted a copy of the Whiting Petroleum Corporation Code of Business Conduct and Ethics on our website at www.whiting.com. The Whiting Petroleum Corporation Code of Business Conduct and Ethics is also available in print to any stockholder who requests it in writing from the Corporate Secretary of Whiting Petroleum Corporation. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding amendments to, or waivers from, the Whiting Petroleum Corporation Code of Business Conduct and Ethics by posting such information on our website at www.whiting.com.

We are not including the information contained on our website as part of, or incorporating it by reference into, this report.

Item 11. Executive Compensation

The information required by this Item is included under the captions “Corporate Governance – Director Compensation” and “Executive Compensation” (other than “Executive Compensation – Proposal 2 – Advisory Vote on the Compensation of Our Named Executive Officers”) in the Proxy Statement and is incorporated herein by reference.

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

The information required by this Item with respect to security ownership of certain beneficial owners and management is included under the captions “Share Ownership – Directors and Executive Officers” and “Share Ownership – Certain Beneficial Owners” in the Proxy Statement and is incorporated herein by reference. The following table sets forth information with respect to compensation plans under which equity securities of Whiting Petroleum Corporation are authorized for issuance as of December 31, 2019.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders [(1)]	42,960	$ 192.88	3,698,933 [(2)]
Equity compensation plans not approved by security holders	—	N/A	—
Total	42,960	$ 195.92	3,698,933 [(2)]

(1) Includes the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the “2003 Equity Plan”) and Whiting Petroleum Corporation 2013 Equity Incentive Plan, as amended and restated (the “2013 Equity Plan”). Upon shareholder approval of the 2013 Equity Plan in May 2013, the 2003 Equity Plan was terminated, but continues to govern awards that were outstanding at the date of its termination. Any shares netted or forfeited under the 2003 Equity Plan and any shares forfeited under the 2013 Equity Plan will be available for future issuance under the 2013 Equity Plan. However, shares netted for tax withholding under the 2013 Equity Plan will be cancelled and will not be available for future issuance.

(2) Number of securities reduced by 42,960 stock options outstanding and 915,889 shares of restricted common stock previously issued for which the restrictions have not lapsed.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by this Item is included under the caption "Corporate Governance – Governance Information – Independence of Directors" and "Corporate Governance – Governance Information – Transactions with Related Persons" in the Proxy Statement and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required by this Item is included under the caption "Audit Matters – Audit and Non-Audit Fees and Services" in the Proxy Statement and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial statements – Refer to the Index to Consolidated Financial Statements included in Item 8 of this Form 10-K for a list of all financial statements filed as part of this report.

2. Financial statement schedules – All schedules are omitted since the required information is not present, or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

3. Exhibits – The exhibits listed in the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Exhibits

The exhibits listed in the accompanying exhibit index are filed (except where otherwise indicated) as part of this report.

Item 16. Form 10-K Summary

None.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on November 9, 2017 (File No. 001-31899)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation, effective October 24, 2017 [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on October 26, 2017 (File No. 001-31899)].
(4.1)	Seventh Amended and Restated Credit Agreement, dated as of April 12, 2018, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various other agents party thereto [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on April 13, 2018 (File No. 001-31899)].
(4.2)	First Amendment to Seventh Amended and Restated Credit Agreement, dated as of September 13, 2019, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 16, 2019 (File No. 001-31899)].
(4.3)	Indenture, dated September 12, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 12, 2013 (File No. 001-31899)].
(4.4)	Second Supplemental Indenture, dated September 12, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 5.75% Senior Notes due 2021 [Incorporated by reference to Exhibit 4.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 12, 2013 (File No. 001-31899)].
(4.5)	Supplemental Indenture and Amendment – Subsidiary Guarantee, dated as of December 11, 2014, among Whiting Petroleum Corporation, Whiting Canadian Holding Company ULC, Whiting Resources Corporation, Whiting US Holding Company and The Bank of New York Mellon Trust Company, N.A., as trustee, relating to the 5.75% Senior Notes Due 2021 [Incorporated by reference to Exhibit 4.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on December 12, 2014 (File No. 001-31899)].
(4.6)	Fourth Supplemental Indenture, dated March 27, 2015, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 6.25% Senior Notes due 2023 [Incorporated by reference to Exhibit 4.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on March 30, 2015 (File No. 001-31899)].
(4.7)	Fifth Supplemental Indenture, dated December 27, 2017, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and the Bank of New York Mellon Trust Company, N.A. as Trustee, creating the 6.625% Senior Notes due 2026 [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on December 27, 2017 (File No. 001-31899)].
(4.8)	Indenture, dated March 27, 2015, among Whiting Petroleum Corporation, the Guarantors and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 1.25% Convertible Senior Notes due 2020 [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on March 30, 2015 (File No. 001-31899)].
(4.9)	Description of Securities.
(10.1)*	Whiting Petroleum Corporation 2003 Equity Incentive Plan, as amended through October 23, 2007 [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on October 29, 2007 (File No. 001-31899)].
(10.2)*	Whiting Petroleum Corporation 2013 Equity Incentive Plan, as amended and restated [Incorporated by reference to Exhibit A to Whiting Petroleum Corporation's definitive proxy statement filed with the Securities and Exchange Commission on Schedule 14A on March 19, 2019 (File No. 001-31899)].
(10.3)*	Summary of Non-Employee Director Compensation for Whiting Petroleum Corporation.
(10.4)*	Form of Indemnification Agreement for directors and officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on

Form 10-Q for the quarter ended September 30, 2008 (File No. 001-31899)].

Exhibit Number	Exhibit Description
(10.5)*	Form of Executive Employment and Severance Agreement for executive officers of Whiting Petroleum Corporation other than Bradley J. Holly and Charles J. Rimer [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on January 5, 2015 (File No. 001-31899)].
(10.6)*	Form of Stock Option Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan [Incorporated by reference to Exhibit 10.14 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-31899)].
(10.7)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan for time-based vesting awards [Incorporated by reference to Exhibit 10.10 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2016 (File No. 001-31899)].
(10.8)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan for time-based vesting awards granted to executive officers.
(10.9)*	Form of Stock Option Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan [Incorporated by reference to Exhibit 10.16 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2013 (File No. 001-31899)].
(10.10)*	Form of Performance Share Award Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan granted in 2018. [Incorporated by reference to Exhibit 10.11 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2017 (File No. 001-31899)].
(10.11)*	Form of Performance Share Award Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan granted in 2020.
(10.12)*	Form of Restricted Stock Unit Award Agreement (Cash-Settled) pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on October 26, 2017 (File No. 001-31899)].
(10.13)*	Form of Restricted Stock Unit Agreement (Cash-Settled) pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan granted to executive officers.
(10.14)*	Form of Restricted Stock Unit Award Agreement (Stock-Settled) pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan for awards granted prior to August 24, 2018 [Incorporated by reference to Exhibit 10.4 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on October 26, 2017 (File No. 001-31899)].
(10.15)*	Letter Agreement, dated August 24, 2018, Amending Outstanding Restricted Stock and Performance Share Awards and Executive Employment and Severance Agreement [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 30, 2018 (File No. 001-31899)].
(10.16)*	Form of Restricted Stock Unit Award Agreement (Stock-Settled) pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan for awards granted on or after August 24, 2018 [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K Filed on August 30, 2018 (File No. 001-31899)].
(10.17)*	Form of Performance Share Unit Award Agreement pursuant to the Whiting Petroleum Corporation 2013 Equity Incentive Plan [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 30, 2018 (File No. 001-31899)].
(10.18)*	Executive Employment and Severance Agreement, between Charles J. Rimer and Whiting Petroleum Corporation, effective as of November 15, 2018 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K as filed on November 15, 2018 (File No. 001-31899)].
(10.19)*	Executive Employment and Severance Agreement, between Bradley J. Holly and Whiting Petroleum Corporation, effective as of November 1, 2017 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K as filed on October 26, 2017 (File No. 001-31899)].
(10.20)*	Non-Competition and Non-Solicitation Agreement, between Michael J. Stevens and Whiting Petroleum Corporation effective as of August 1, 2019 [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on July 16, 2019 (File No. 001-31899)].
(21)	Significant Subsidiaries of Whiting Petroleum Corporation.
(23.1)	Consent of Deloitte & Touche LLP.
(23.2)	Consent of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers.
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.

(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350.

Exhibit Number	Exhibit Description
(99)	Report of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers relating to Total Proved Reserves, dated February 7, 2020.
(101)	The following materials from Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2019 are filed herewith, formatted in iXBRL (Inline Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of December 31, 2019 and 2018, (ii) the Consolidated Statements of Operations for the Years Ended December 31, 2019, 2018 and 2017, (iii) the Consolidated Statements of Cash Flows for the Years Ended December 31, 2019, 2018 and 2017, (iv) the Consolidated Statements of Equity for the Years Ended December 31, 2019, 2018 and 2017, and (v) Notes to Consolidated Financial Statements. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the iXBRL document.
(104)	Cover Page Interactive Data File (formatted as Inline XBRL) – The cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the iXBRL document.

* A management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 27th day of February, 2020.

WHITING PETROLEUM CORPORATION

By /s/ Bradley J. Holly
Bradley J. Holly
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ Bradley J. Holly Bradley J. Holly	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 27, 2020
/s/ Correne S. Loeffler Correne S. Loeffler	Chief Financial Officer (Principal Financial Officer)	February 27, 2020
/s/ Sirikka R. Lohoefener Sirikka R. Lohoefener	Vice President and Controller (Principal Accounting Officer)	February 27, 2020
/s/ Thomas L. Aller Thomas L. Aller	Director	February 27, 2020
/s/ Lyne B. Andrich Lyne B. Andrich	Director	February 27, 2020
/s/ James E. Catlin James E. Catlin	Director	February 27, 2020
/s/ Philip E. Doty Philip E. Doty	Director	February 27, 2020
/s/ William N. Hahne William N. Hahne	Director	February 27, 2020
/s/ Michael G. Hutchison Michael G. Hutchison	Director	February 27, 2020
/s/ Carin S. Knickel Carin S. Knickel	Director	February 27, 2020
/s/ Michael B. Walen Michael B. Walen	Director	February 27, 2020