WHITING PETROLEUM CORP
Form S-4
May 25, 2018

As filed with the Securities and Exchange Commission on May 25, 2018

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM S-4

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

WHITING PETROLEUM CORPORATION*

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

1311

(Primary Standard Industrial Classification Code Number)

20-0098515

(I.R.S. Employer Identification Number)

1700 Broadway, Suite 2300

Denver, Colorado 80290

(303) 837-1661

(Address, including zip code and telephone number, including area code, of registrant s principal executive offices)

Bradley J. Holly

Chairman, President and Chief Executive Officer

1700 Broadway, Suite 2300

Denver, Colorado 80290

(303) 837-1661

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copy to:

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John K. Wilson, Esq.

Foley & Lardner LLP

777 East Wisconsin Avenue

Milwaukee, Wisconsin 53202

(414) 271-2400

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effectiveness of this registration statement and the satisfaction or waiver of all other conditions pursuant to the exchange offer described herein.

If the securities being registered on this Form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box.

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering.

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

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act.

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issue Tender Offer)

Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer)

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	Amount to be registered	Proposed maximum offering price per unit(1)	Proposed maximum aggregate offering price(1)	Amount of registration fee
6.625% Senior Notes due 2026(2)	$1,000,000,000	100%	$1,000,000,000	$124,500
Guarantee for the 6.625% Senior Notes due 2026	(3)	(3)	(3)	(3)

(1) Exclusive of accrued interest, if any, and estimated solely for purposes of determining the registration fee.
(2) Calculated pursuant to Rule 457(f)(2) under the Securities Act of 1933.
(3) Pursuant to Rule 457(n) under the Securities Act of 1933, no registration fee is required with respect to the guarantees.

The registrants hereby amend this registration statement on such date or dates as may be necessary to delay its effective date until the registrants shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

*** ADDITIONAL REGISTRANTS**

Name, Address and Telephone Number	State or Other Jurisdiction of Incorporation	Primary Standard Industrial Classification Number	I.R.S. Employer Identification Number
Whiting Oil and Gas Corporation 1700 Broadway, Suite 2300 Denver, Colorado 80290-2300 (303) 837-1661	Delaware	1311	84-0918829
Whiting US Holding Company 1700 Broadway, Suite 2300 Denver, Colorado 80290-2300 (303) 837-1661	Delaware	1311	47-2452900
Whiting Canadian Holding Company ULC 1700 Broadway, Suite 2300 Denver, Colorado 80290-2300 (303) 837-1661	British Columbia	1382	N/A
Whiting Resources Corporation 1700 Broadway, Suite 2300 Denver, Colorado 80290-2300 (303) 837-1661	Colorado	1382	57-1191218

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is declared effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to completion

Preliminary prospectus dated May 25, 2018

PROSPECTUS

Whiting Petroleum Corporation

Offer to Exchange All Outstanding, Unregistered

$1,000,000,000 6.625% Senior Notes due 2026

For New, Registered

$1,000,000,000 6.625% Senior Notes due 2026

We are offering, upon the terms and subject to the conditions set forth in this prospectus, to exchange all of our outstanding unregistered 6.625% Senior Notes due 2026 (the original notes) issued December 27, 2017, for our new, registered 6.625% Senior Notes due 2026 (the new notes). Initially, the new notes will be guaranteed by each of our subsidiaries that is an obligor or guarantor under certain of our existing indebtedness. In the future, the new notes will be guaranteed by each of our newly created or acquired material domestic subsidiaries and by any of our other restricted subsidiaries that becomes a borrower or guarantees any of our or our restricted subsidiaries indebtedness under the Credit Agreement (as defined below) or certain capital markets indebtedness.

The material terms of the exchange offer include the following:

The exchange offer expires at 5:00 p.m., New York City time, on , 2018, unless we extend it.

All outstanding original notes that are validly tendered and not validly withdrawn will be exchanged.

You may withdraw your tender of original notes any time before the exchange offer expires.

The terms of the new notes are substantially identical to those of the original notes, except that the new notes will not have securities law transfer restrictions and the registration rights relating to the original notes and the new notes will not provide for the payment of additional interest under circumstances relating to the timing of the exchange offer.

We will not receive any proceeds from the exchange offer.

No established trading market for the new notes currently exists. The new notes will not be listed on any securities exchange or included in any automated quotation system.

The exchange of notes will not be a taxable event for U.S. federal income tax purposes.

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. The letter of transmittal for the exchange offer states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act of 1933, as amended (the Securities Act). This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for original notes where such original notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that for a period of 180 days beginning when the new notes are issued to make this prospectus available to any broker-dealer for use in connection with any such resale. See Plan of Distribution.

See Risk Factors beginning on page 14 for a discussion of risk factors that you should consider before deciding to exchange your original notes for new notes.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2018

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You should rely only on the information contained in this prospectus. We have not authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information appearing in this prospectus as well as the documents incorporated by reference in this prospectus, is accurate only as of its respective date. Our business, financial condition, results of operations and prospects may have changed since that date.

In this prospectus, except as otherwise noted, we, us, our or ours refer to Whiting Petroleum Corporation and its consolidated subsidiaries.

This prospectus incorporates important business and financial information about us that is not included in or delivered with this prospectus. We will provide you without charge upon your request, a copy of any documents that we incorporate by reference, other than exhibits to those documents that are not specifically incorporated by reference into those documents. You may request a copy of a document, at no cost, by request directed to us at the following address or telephone number:

Whiting Petroleum Corporation

1700 Broadway, Suite 2300

Denver, Colorado 80290-2300

Attention: Corporate Secretary

(303) 837-1661

To ensure timely delivery, you must request the information no later than five (5) business days before the completion of the exchange offer. Therefore, you must make any request on or before , 2018.

GLOSSARY OF CERTAIN DEFINITIONS

We have included below the definitions for certain terms used in this prospectus:

3-D seismic Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

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.

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.

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.

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.

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.

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.

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, 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. See note 2 to the Proved Reserves table in Prospectus Summary Our company of this prospectus for more information.

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.

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.

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.

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 risks in connection therewith.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus and the documents incorporated by reference herein contain statements that we believe to be forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than historical facts, including, without limitation, statements regarding this exchange offer, 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. We caution that these statements and any other forward-looking statements in this prospectus and the documents incorporated by reference herein only reflect our expectations and do not guarantee performance. When used in this prospectus and the documents incorporated by reference herein, words such as we expect, intend, plan, estimate, anticipate, believe or should or the negative thereof or variations 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, ability to comply with debt covenants and periodic redeterminations of the borrowing base under our Credit Agreement;
- impacts to financial statements as a result of impairment write-downs;
- our ability to successfully complete asset dispositions and the risks related thereto, including the potential disposition of our Redtail field assets;
- revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors;
- adverse weather conditions that may negatively impact development or production activities;
- the timing of our exploration and development expenditures;
- inaccuracies of our reserve estimates or our assumptions underlying them;
- risks relating to any unforeseen liabilities of ours;

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;

federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions;

unforeseen underperformance of or liabilities associated with acquired properties;

the impacts of hedging on our results of operations;

failure of our properties to yield oil or gas in commercially viable quantities;

availability of, and risks associated with, transport of oil and gas;

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;

uninsured or underinsured losses resulting from our oil and gas operations;

our inability to access oil and gas markets due to market conditions or operational impediments;

the impact and costs of compliance with laws and regulations governing our oil and gas operations;

- the potential impact of changes in laws, including tax reform, that could have a negative effect on the oil and gas industry;
- our ability to replace our oil and natural gas reserves;
- any loss of our senior management or technical personnel;
- competition in the oil and gas industry;
- cyber security attacks or failures of our telecommunication systems; and
- other risks described under the caption Risk Factors in this prospectus.

Except as may be required by law, we assume no obligation, and disclaim any duty, to update the forward-looking statements in this prospectus or the documents we incorporate by reference herein. We urge you to carefully review and consider the disclosures made in this prospectus and our reports filed with the SEC and incorporated by reference herein that attempt to advise interested parties of the risks and factors that may affect our business.

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus and the documents incorporated by reference herein. This summary may not contain all of the information that you need to consider in making your investment decision. You should carefully read the entire prospectus, including Risk Factors, and the documents incorporated by reference into this prospectus before making a decision to participate in the exchange offer of original notes for new notes.

We have provided definitions for the oil and gas terms used in this prospectus in the Glossary of Certain Definitions included in this prospectus.

Our company

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. During 2017, we 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 2018, we continue to focus on high-return projects in our asset portfolio that will add production and reserves while generating free cash flows from operations. In addition, 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 our plan to explore monetization of our Redtail field assets.

As of December 31, 2017, our estimated proved reserves totaled 617.6 MMBOE and our 2017 average daily production was 118.1 MBOE/d, which results in an average reserve life of approximately 14.3 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2017, their corresponding pre-tax PV10% values, and our first quarter 2018 average daily production rates, as well as our total standardized measure of discounted future net cash flows as of December 31, 2017:

	Proved reserves as of December 31, 2017(1)						1st Quarter 2018 Average Daily Production
Core area	**Oil (MMBbl)**	**NGLs (MMBbl)**	**Natural Gas (Bcf)**	**Total (MMBOE)**	**% Oil**	**Pre-tax PV10% Value(2) (in millions)**	**(MBOE/d)**
Northern Rocky Mountains(3)	298.2	133.0	787.4	562.5	53%	$ 3,779	103.1
Central Rocky Mountains(4)	34.9	5.7	55.8	49.9	70%	161	23.3
Other(5)	4.5	0.2	3.3	5.2	86%	29	0.7
Total	**337.6**	**138.9**	**846.5**	**617.6**	**55%**	**$ 3,969**	127.1
Discounted Future Income Tax Expense						(101)	

Standardized Measure of Discounted Future Net Cash Flows	$	**3,868**

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from an oil price of $51.34 per Bbl and a gas price of $2.98 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, 2017 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, New Mexico, Texas and Wyoming.

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:

Developing existing properties. The development of our large resource play at our Williston Basin project has become our central objective. As of December 31, 2017, we have assembled approximately 688,200 gross (409,600 net) developed and undeveloped acres in the Williston Basin located in North Dakota and Montana. As of March 31, 2018, we had four rigs active in the Williston Basin and added a fifth rig in April 2018.

At our Redtail field in the Denver-Julesburg Basin (the DJ Basin) in Weld County, Colorado, we have assembled approximately 120,200 gross (100,000 net) developed and undeveloped acres. In response to low commodity prices, we suspended completion operations in this area beginning in the second quarter of 2016, however, we resumed completion activity during the first quarter of 2017. During 2017, we completed and brought on production a significant portion of our drilled uncompleted well inventory (DUCs) from yearend 2016. During the fourth quarter of 2017, based on the recent and comparative well performance results of the DJ Basin to the Williston Basin, our management decided to concentrate development activities during 2018 in the Williston Basin. We plan to complete 22 DUCs in our Redtail field during the first half of 2018, and then cease additional development activity in this area until commodity prices further recover.

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 March 31, 2018, the plant was processing over 36 MMcf/d.

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. During 2017, we 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 2018, we continue to focus on high-return projects in our asset portfolio that will add production and reserves

while generating free cash flows 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 2016 and 2017 we sold a large number of oil and gas properties and other related assets that no longer matched the profile of properties we desire to own and we are currently exploring a plan to monetize our Redtail field assets. 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. As of May 9, 2018, we had derivative contracts covering the sale of approximately 73% of our forecasted oil production volumes for the remainder of 2018.

Growing through accretive acquisitions. Since 2003, we have completed 21 separate significant acquisitions of producing properties for total estimated proved reserves of 445.2 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, 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.

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, 2017, we had interests in 4,775 gross (1,980 net) productive wells on approximately 802,700 gross (490,000 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 14.3 years based on year-end 2017 proved reserves and 2017 production.

Experienced management and technical teams. Our management team averages 29 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 33 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 geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Data provided by our in-house, state-of-the-art rock analysis laboratory is used to support real-time drilling and completion decisions, and to help us further understand unconventional oil plays. Our technical team has access to approximately 9,200 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand-held computers in the field. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

We continue to advance our completion techniques, including significantly increasing proppant volumes, utilizing diverter agents to better distribute fluid and proppant across individual zones, varying the number of completion stages, and employing new fracture stimulation fluids, including slickwater. We plan to continue use

of these state-of-the-art completion designs on wells we drill throughout 2018, while also testing new diversion technology and more efficient placement and drillout of down-hole plugs.

Recent developments

Redemption of 2019 Notes. On January 26, 2018, we paid $1.0 billion to redeem all of the remaining $961 million aggregate principal amount of our outstanding 5.00% Senior Notes due 2019, 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 the original notes and borrowings under the Sixth Amended and Restated Credit Agreement, dated as of August 27, 2014. As a result of the redemption, we recognized a $31 million loss on extinguishment of debt, which included the redemption premium and a non-cash charge for the acceleration of unamortized debt issuance costs on the notes.

Seventh Amended and Restated Credit Agreement. On April 12, 2018, we entered into a Seventh Amended and Restated Credit Agreement (the Credit Agreement), which replaced the existing credit agreement. The Credit Agreement, among other things, (i) increased the borrowing base under the facility from $2.3 billion to $2.4 billion, (ii) reduced the aggregate commitments from $2.3 billion to $1.75 billion, (iii) extended the principal repayment date from December 2019 to April 2023, (iv) decreased the applicable margin based on the borrowing base utilization percentage by 50 basis points per annum, (v) decreased the commitment fee to 37.5 basis points per annum for certain ratios of outstanding borrowings to the borrowing base, (vi) modified certain financial covenants, and (vii) removed our ability to issue second lien indebtedness of up to $1.0 billion.

Corporate information

We were incorporated in Delaware in July 2003, in connection with our initial public offering. Our principal executive offices are located at 1700 Broadway, Suite 2300, Denver, Colorado 80290-2300, and our telephone number is (303) 837-1661.

The Exchange Offer

The following is a brief description of the material terms of the exchange offer. We are offering to exchange the original notes for the new notes. The terms of the new notes offered in the exchange offer are substantially identical to the terms of the original notes, except that the new notes will be registered under the Securities Act and certain transfer restrictions, registration rights and additional interest provisions relating to the original notes do not apply to the new notes. For a more complete description, see Description of New Notes.

Original notes	$1,000,000,000 aggregate principal amount of 6.625% Senior Notes due 2026. The original notes were issued in transactions exempt from registration under the Securities Act and are subject to transfer restrictions.
New notes	$1,000,000,000 aggregate principal amount of 6.625% Senior Notes due 2026.
The exchange offer	We are offering to exchange $1,000 principal amount of the new notes for each $1,000 principal amount of your original notes. Original notes tendered in the exchange offer must be in minimum denominations of $2,000 principal amount and any integral multiples of $1,000 in excess thereof. In order for us to exchange your original notes, you must validly tender them to us and we must accept them. For procedures for tendering, see The Exchange Offer Procedures for tendering original notes.
Expiration date	The exchange offer will expire at 5:00 p.m., New York City time, on, 2018, unless we extend it.
Acceptance of original notes and delivery of new notes	We will accept for exchange any and all original notes that are validly tendered in the exchange offer and not withdrawn before the exchange offer expires. The new notes will be delivered promptly following the exchange offer.
Withdrawal rights	You may withdraw your tender of original notes at any time before the exchange offer expires.
Conditions of the exchange offer	Our obligation to consummate the exchange offer is not subject to any conditions, other than that the exchange offer does not violate any applicable law or SEC staff interpretation. See The Exchange Offer Conditions. We reserve the right to terminate or amend the

	exchange offer at any time prior to the expiration date if, among other things, there shall have been proposed, adopted or enacted any law, statute, rule, regulation or SEC staff interpretation which, in our judgment, could reasonably be expected to materially impair our ability to proceed with the exchange offer.
Consequences of failure to exchange	If you are eligible to participate in the exchange offer and you do not tender your original notes, then you will not have further exchange or

	registration rights and you will continue to hold original notes subject to restrictions on transfer.
Federal income tax considerations	The exchange of original notes for new notes will not be a taxable event for federal income tax purposes. See Material U.S. Federal Income Tax Considerations.
Use of proceeds	We will not receive any proceeds from the exchange offer.
Accounting treatment	We will not recognize any gain or loss on the exchange of notes. See The Exchange Offer Accounting treatment.
Exchange agent	The Bank of New York Mellon Trust Company, N.A. is the exchange agent. See The Exchange Offer Exchange agent.
Resales of new notes	Based on interpretations by the staff of the SEC set forth in no-action letters issued to other parties, we believe that the new notes issued pursuant to the exchange offer in exchange for original notes may be offered for resale, resold and otherwise transferred by you without compliance with the registration and prospectus delivery provisions of the Securities Act if:
	you are not our affiliate within the meaning of Rule 405 under the Securities Act;
	you are acquiring the new notes in the ordinary course of your business;
	you have not engaged in, do not intend to engage in, and have no arrangement or understanding with any person to participate in, a distribution (within the meaning of the Securities Act) of the new notes; and
	you are not acting on behalf of any person who could not truthfully make the foregoing representations.
	If you are an affiliate of ours, or are engaging in or intend to engage in, or have any arrangement or understanding with any person to participate in, a distribution of the new notes, then:

you may not rely on the applicable interpretations of the staff of the SEC;

you will not be permitted to tender original notes in the exchange offer; and

you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the original notes.

Each participating broker-dealer that receives new notes for its own account under the exchange offer in exchange for original notes that were acquired by the broker-dealer as a result of market making or other trading activity must acknowledge that it will deliver a prospectus in connection with any resale of the new notes.

Any broker-dealer that acquired original notes from us may not rely on the applicable interpretations of the staff of the SEC and must comply with registration and prospectus delivery requirements of the Securities Act (including being named as a selling security holder) in connection with any resales of the original notes or the new notes.

See The Exchange Offer Procedures for tendering original notes and Plan of Distribution.

The New Notes

The summary below describes the principal terms of the new notes and the new note guarantees. Certain of the terms and conditions described below are subject to important limitations and exceptions. Refer to Description of New Notes in this prospectus for a more detailed description of the terms of the new notes and the new note guarantees.

As used in this section, the terms the Company, us, we or our refer to Whiting Petroleum Corporation and not any of its subsidiaries.

Issuer	Whiting Petroleum Corporation, a Delaware corporation.
Securities offered	Up to $1,000,000,000 aggregate principal amount of 6.625% Senior Notes due 2026.
Maturity date	January 15, 2026.
Interest rate	6.625% per year.
Interest payment dates	January 15 and July 15, commencing July 15, 2018. Interest will accrue from December 27, 2017.
Optional redemption	At any time prior to October 15, 2025 (the date three months prior to the maturity date), we may redeem all or a portion of the new notes at a redemption price equal to 100% of the principal amount of the new notes redeemed, plus a make-whole premium described in this prospectus, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption.
	On and after October 15, 2025 (the date three months prior to the maturity date), we may redeem all or a portion of the new notes at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption.
Change of control triggering event	Upon the occurrence of certain change of control events followed by a rating decline, we will be required to offer to repurchase all or any portion (equal to $2,000 or any integral multiple of $1,000 in excess thereof) of the new notes at a price equal to 101% of the principal amount of the new notes, plus accrued and unpaid interest, if any, to, but excluding, the date of repurchase. See Description of New Notes Repurchase at the option of holders Change of control triggering

	event.
Asset disposition offer	If we or any of our restricted subsidiaries sell assets, under certain circumstances, we will be required to use the net proceeds to make an offer to purchase the new notes at an offer price in cash in an amount equal to 100% of the principal amount of the new notes, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date. See Description of New Notes Repurchase at the option of holders Asset sales.

New note guarantees	Initially, the new notes will be guaranteed by each of our subsidiaries that is an obligor or guarantor under certain of our existing indebtedness. In the future, the new notes will be guaranteed by each of our newly created or acquired material domestic subsidiaries and by any of our other restricted subsidiaries that becomes a borrower or guarantees any of our or our restricted subsidiaries indebtedness under the Credit Agreement or certain capital markets indebtedness.
Ranking	The new notes and new note guarantees will be our and the guarantors senior unsecured obligations and will: rank equally in right of payment with all existing and future senior indebtedness, including our guarantee of the borrowings under the Credit Agreement, and our existing senior notes; rank senior in right of payment to all of our future subordinated indebtedness; be effectively subordinated to all of our secured indebtedness (including our guarantee of the borrowings under the Credit Agreement) to the extent of the value of the collateral securing such indebtedness; and be structurally subordinated to all indebtedness and other liabilities of our non-guarantor subsidiaries (including trade payables). As of March 31, 2018, the Company and the guarantors had $90 million in borrowings and $2 million in letters of credit outstanding under the prior credit agreement, with $2.2 billion of available borrowing capacity (which was subsequently reduced to $1.7 billion in connection with entering into the amended and restated Credit Agreement on April 12, 2018). For the 12 months ended March 31, 2018, the non-guarantor subsidiaries generated less than 0.1% of our consolidated revenues and as of March 31, 2018, had no indebtedness (other than intercompany indebtedness) and held less than 0.3% of our consolidated assets.
Certain covenants	The indenture that will govern the new notes will contain covenants that, among other things, will limit our ability and the ability of our restricted subsidiaries to:

pay dividends or make other distributions or repurchase or redeem our capital stock;

prepay, redeem or repurchase certain debt;

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 the assets of us and our restricted subsidiaries taken as a whole;
	engage in transactions with affiliates; and
	create unrestricted subsidiaries.
	These covenants are subject to important exceptions and qualifications that are described under the heading Description of New Notes in this prospectus. In addition, many of these covenants will terminate if the new notes achieve an investment-grade rating from each of Moody s Investors Service, Inc. (Moody s) and S&P Global Ratings (S&P).
Book-entry form	The new notes will be issued in book-entry form and will be represented by permanent global certificates deposited with, or on behalf of, The Depository Trust Company (DTC) and registered in the name of a nominee of DTC. Beneficial interests in any of the new notes will be shown on, and transfers will be effected only through, records maintained by DTC or its nominee and any such interest may not be exchanged for certificated securities, except in limited circumstances.
Absence of a public market for the new notes	The new notes are a new issue of securities and there is currently no established market for the new notes. We do not intend to apply for a listing of the new notes on any securities exchange or an automated dealer quotation system. Accordingly, a liquid market for the new notes may not develop.
Trustee and paying agent	The Bank of New York Mellon Trust Company, N.A.
Use of proceeds	We will not receive any cash proceeds from the issuance of the new notes.
Material U.S. federal income tax considerations	The material U.S. federal income tax considerations of purchasing, owning and disposing of the new notes are described in Material U.S. Federal Income Tax Considerations.

Risk factors	In evaluating an investment in the new notes, prospective investors should carefully consider, along with the other information in this prospectus, the specific factors set forth under Risk Factors for risks involved with participating in the exchange offer and an investment in the new notes.

Selected Historical and Pro Forma Consolidated Financial Information

The following selected historical consolidated financial information for the years ended December 31, 2015, 2016 and 2017 and as of December 31, 2016 and 2017 has been derived from our audited consolidated financial statements and related notes incorporated by reference into this prospectus. The following selected historical consolidated financial information for the years ended December 31, 2013 and 2014 and as of December 31, 2013, 2014 and 2015 has been derived from our audited consolidated financial statements and related notes not included or incorporated by reference into this prospectus. The following selected historical consolidated financial information for the three months ended March 31, 2017 and 2018 and as of March 31, 2018 has been derived from our unaudited condensed consolidated financial statements and related notes incorporated by reference into this prospectus. The following selected historical consolidated financial information as of March 31, 2017 has been derived from our unaudited condensed consolidated financial statements and related notes not included or incorporated by reference into this prospectus. Our historical results are not necessarily indicative of future operating results. This information is only a summary and you should read it in conjunction with our consolidated financial statements and related notes and Management s Discussion and Analysis of Financial Condition and Results of Operations included in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 and our Annual Report on Form 10-K for the year ended December 31, 2017, which are incorporated by reference in this prospectus.

The following selected unaudited pro forma consolidated financial information for the year ended December 31, 2017 has been derived from and should be read in conjunction with our unaudited pro forma consolidated statement of operations and related notes incorporated by reference into this prospectus. The unaudited pro forma consolidated statements of operations for the year ended December 31, 2017 gives effect to the disposition of certain oil and gas producing properties in the Fort Berthold Indian Reservation area located in Dunn and McLean counties of North Dakota as well as certain other related assets and liabilities (the FBIR Properties) as if it had occurred on January 1, 2016. In our opinion, all adjustments that are necessary to present fairly the pro forma consolidated information have been made. The following unaudited pro forma consolidated financial information does not purport to represent what our results of operations would have been if the disposition of the FBIR Properties had occurred on such date, nor is it indicative of future results of operations. In addition, the unaudited pro forma consolidated statement of operations does not give effect to our debt offering that was completed in December 2017 or this exchange offer.

	Year ended December 31,						Three months ended March 31,	
	2013	**2014**	**2015**	**2016**	**2017**	**2017 pro forma**	**2017**	**2018**
(in millions, except per share data)								
Consolidated Statements of Operations Information:								
Operating revenues	$ 2,664.6	$ 3,024.6	$ 2,092.5	$ 1,285.0	$ 1,481.4	$ 1,399.6	$ 371.3	$ 515.1
Net income (loss) available to common shareholders	$ 365.5	$ 64.8	$ (2,219.2)	$ (1,339.1)	$ (1,237.6)	$ (811.2)	$ (87.0)	$ 15.0
	$ 12.36	$ 2.12	$ (45.41)	$ (21.27)	$ (13.65)	$ (8.95)	$ (0.96)	$ 0.17

Earnings (loss) per common share, basic[1]								
Earnings (loss) per common share, diluted[1]	$ 12.25	$ 2.12	$ (45.41)	$ (21.27)	$ (13.65)	$ (8.95)	$ (0.96)	$ 0.16
Other Financial Information:								
Net cash provided by operating activities	$ 1,744.7	$ 1,815.3	$ 1,051.4	$ 595.0	$ 577.1	N/A	$ 80.1	$ 232.9
Net cash provided by (used in) investing activities	(1,902.5)	(2,860.5)	(1,982.1)	(222.6)	73.4	N/A	243.1	(177.4)
Net cash provided by (used in) financing activities	812.4	423.9	868.7	(315.3)	155.6	N/A	(380.0)	(904.3)
Consolidated Balance Sheet Information:								
Total assets	$ 8,802.5	$ 13,993.1	$ 11,389.1	$ 9,876.1	$ 8,403.0	N/A	$ 9,387.7	$ 7,532.7
Long-term debt	2,622.9	5,602.4	5,197.7	3,535.3	2,764.7	N/A	3,168.3	2,861.4
Total equity[2]	3,836.7	5,703.0	4,758.6	5,149.2	3,919.1	N/A	5,063.3	3,935.6

(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 the year ended December 31, 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.

Summary Historical Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of December 31, 2015, 2016 and 2017 and our historical operating data for the years ended December 31, 2015, 2016 and 2017. The reserve estimates presented in the table below are based on reports prepared by Cawley Gillespie & Associates, Inc., independent reserve engineers. Estimates of proved oil and natural gas reserves are inherently uncertain, and any material inaccuracies in the estimates prepared by our external reserve engineers will materially affect the quantities and values of our reserves. All calculations of estimated net proved reserves have been made in accordance with the SEC s rules and regulations regarding oil and natural gas reserve reporting that are currently in effect. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical data presented below should not be interpreted as being indicative of future results.

You should refer to Risk Factors, elsewhere in this prospectus and Business and Management s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2017, and our financial statements and notes thereto contained in such report, which are incorporated by reference in this prospectus, in evaluating the information presented below.

	As of December 31,		
	2015	**2016**	**2017**
Reserve data:[(1)]			
Total estimated proved developed reserves:			
Oil (MBbl)	298,444	183,165	179,829
NGLs (MBbl)	55,437	51,888	76,957
Natural gas (MMcf)	300,631	337,860	473,829
Total (MBOE)	403,986	291,363	335,758
Total estimated proved reserves:			
Oil (MBbl)	596,677	394,767	337,583
NGLs (MBbl)	112,947	101,493	138,949
Natural gas (MMcf)	665,660	715,659	846,477
Total (MBOE)	820,567	615,537	617,612
Pre-tax PV10% (in millions)[(2)]	$ 4,617	$ 2,698	$ 3,969
Standardized measure of discounted future net cash flows (in millions)	$ 4,574	$ 2,698	$ 3,868

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2015, 2016 and 2017, respectively, pursuant to 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, 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 the Standardized Measure do not purport to present the fair value of our proved oil, NGL and natural gas reserves.

	Year ended December 31, 2015	2016	2017
Operating data:			
Net production:			
Oil (MMBbl)	47.2	34.0	29.3
NGLs (MMBbl)	5.5	6.6	7.0
Natural gas (Bcf)	41.1	41.4	41.3
Total production (MMBOE)	59.6	47.5	43.1
Net sales (in millions):			
Oil(1)	$ 1,931.9	$ 1,167.8	$ 1,296.4
NGLs	70.2	59.0	111.6
Natural gas	90.4	58.2	73.4
Total oil, NGL and natural gas sales	$ 2,092.5	$ 1,285.0	$ 1,481.4
Average sales prices:			
Oil (per Bbl)(1)	$ 40.95	$ 34.36	$ 44.30
Effect of oil hedges on average price (per Bbl)	4.59	4.46	0.29
Oil net of hedging (per Bbl)	$ 45.54	$ 38.82	$ 44.59
Weighted average NYMEX price (per Bbl)(2)	$ 49.06	$ 42.71	$ 51.11
NGLs (per Bbl)	$ 12.67	$ 8.88	$ 16.00
Natural gas (per Mcf)	$ 2.20	$ 1.40	$ 1.78
Weighted average NYMEX price (per MMBtu)(2)	$ 2.62	$ 2.47	$ 2.97
Costs and expenses (per BOE):			
Lease operating expenses	$ 9.32	$ 8.31	$ 8.51
Production taxes	$ 3.07	$ 2.29	$ 2.86
Depreciation, depletion and amortization	$ 20.87	$ 24.64	$ 22.01
General and administrative	$ 2.90	$ 3.09	$ 2.88

(1) Before consideration of hedging transactions.
(2) Average NYMEX pricing weighted for monthly production volumes.

RISK FACTORS

Each of the risks described below should be carefully considered, together with all of the other information contained or incorporated by reference in this prospectus, before making an investment decision with respect to participating in the exchange offer of original notes for new notes. 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.

Risks related to our business

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 foreign oil and natural gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, such as the recent conflicts in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the effects of global credit, financial and economic issues;
- developments of United States energy infrastructure;
- weather conditions;
- technological advances affecting energy consumption;

- current and anticipated changes to domestic and foreign governmental regulations, including those expected as a result of the election of Donald Trump to the U.S. Presidency;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors supplies of oil and natural gas in captive market areas;
- the price and availability of alternative fuels; and
- acts of force majeure.

Moreover, government regulations, such as regulation of oil and natural gas gathering and transportation, can adversely affect commodity prices in the long term.

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, such as those described in Summary Recent developments 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 have reduced, and may further 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 borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our Credit Agreement.

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 Risks related to the exchange offer and new notes The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

Alternatively, higher oil 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 or results of operations.

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. Please read 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 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 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 on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;

shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and, completion services;

equipment failures or accidents;

adverse weather conditions, such as freezing temperatures, hurricanes and storms;

pipeline takeaway and refining and processing capacity; and

title problems.

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 and other factors) we may be required to write down the carrying value of our oil and gas properties. For example, we recorded a $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 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. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of Colorado, Montana and North Dakota, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency (the EPA) also issued guidance in 2014 for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

In December 2016, the EPA released a final report on the potential impacts of oil and gas fracturing activities on the quality and quantity of drinking water resources in the United States. In addition, in June 2016, the EPA issued a final rule promulgating pretreatment standards for the oil and gas extraction category which would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly-owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities accepting oil and gas extraction wastewater. The EPA is collecting data and information regarding the extent to which these facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of the facilities, the environmental impacts of discharges and other information.

Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. In March 2015, the U.S. Department of the Interior released a final rule addressing (i) hydraulic fracturing on federal and Indian oil and natural gas leases to require validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes, (ii) disclosure of chemicals used in hydraulic fracturing to the Bureau of Land Management, (iii) higher standards for interim storage of recovered waste fluids from hydraulic fracturing, and (iv) measures to lower the risk of cross-well contamination with chemicals and fluids used in fracturing operations. This rule was challenged in federal court and in June 2016, the Wyoming District Court hearing the case ruled that the Department of the Interior had exceeded its authority in issuing the rule. In March 2017, Justice Department lawyers representing the Bureau of Land Management asked the Court of Appeals for the Tenth Circuit to stay the government s previously filed appeal as the Trump Administration was planning to rescind the rules; and in July 2017, the Department of the Interior announced its proposal to rescind the rules, with the public comment period on the proposal closing in September 2017. On December 29, 2017, the Department of the Interior issued a final rule rescinding the 2015 rule.

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. Also, some states have adopted, and other states are considering adopting, regulations that could ban, restrict or impose additional requirements on activities relating to hydraulic fracturing in certain circumstances. For example, in June 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permitting requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt, and some have adopted, ordinances within their jurisdictions restricting the use of or regulating the time, place and manner of drilling or hydraulic fracturing. No assurance can be given as to whether or not similar 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 and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities and the calculation of our reserves.

In addition, in July 2014, a major university and U.S. Geological Survey researchers published a study purporting to find a causal 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.

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. 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.

See Hydraulic Fracturing in Item 2 of our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus, 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, 2017, 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, and two are 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 commitment at our Sanish field in North Dakota, if we fail to deliver the committed volumes, we would be required to pay a deficiency payment of $7.00 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 our two contracts in this area. 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. We expect to make periodic deficiency payments under the second Redtail contract that currently total $4.92 per undelivered Bbl (subject to upward adjustment). During 2017, 2016 and 2015, total deficiency payments under these contracts amounted to $66 million, $43 million and $15 million, respectively.

See Properties Delivery Commitments in

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Item 2 of our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus, 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 prospectus and in our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus.

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:

- 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 prospectus and in our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus. 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 prospectus and in our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus, 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, 2017 were $51.34 per Bbl and $2.98 per MMBtu. 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, 2017 would have decreased by $181 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, 2017 would have decreased by $21 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 with cash flow from operations, proceeds from property divestitures, cash on hand and financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

- 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. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing 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.

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 indemnification provisions, which could obligate us to substantial liabilities.

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. Also, we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Please read Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing for a discussion of the uncertainty involved in the regulation of hydraulic fracturing. 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, NGLs 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 the oil, NGLs and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, in response to accidents involving rail cars carrying Bakken formation crude oil, the U.S. Department of Transportation (the DOT) issued an emergency order in February 2014 that requires rail shippers to test the makeup of such crude oil before transporting it. This move follows the safety alert the DOT issued in January 2014 that Bakken formation crude oil is more flammable than other types of crude oil and has been followed by additional emergency orders and safety advisories and alerts. An accident 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 of our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus, 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 loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of air, soil, ground water and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

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, 2017, 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 37% in 2018, 10% in 2019 and 12% in 2020. 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.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;

we may assume liabilities that were not disclosed to us or that exceed our estimates;

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;

we may issue additional equity or debt securities in order to fund future acquisitions; and

we may incur losses as a result of title defects.

The unavailability or high 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 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.

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.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas 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 2017 we recorded a $12 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. See Acreage in Item 2 of our Annual Report on Form 10-K for the year ended December 31, 2017, which is incorporated by reference in this prospectus, for more information relating to the expiration of our rights to develop undeveloped acreage.

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 2004 through 2017, we completed 21 separate significant acquisitions of producing properties with a combined purchase price of $6.4 billion for estimated proved reserves as of the effective dates of the acquisitions of 445.2 MMBOE. The successful acquisition of producing properties requires assessment of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- 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, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

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 May 9, 2018, we had contracts covering the sale of 1,850,000 barrels of oil per month for all of 2018, which represents approximately 73% of our forecasted oil production volumes for the remainder of 2018. All of our oil hedges will expire by June 2019. See Quantitative and Qualitative Disclosures about Market Risk in Item 3 of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2018, which is incorporated by reference in this prospectus, 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 the 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 the spring and summer 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.

An increase in the differential or decrease in the premium between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and 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 difference between the benchmark price and the price received is called a differential and a positive difference is called a premium. The differential and premium may vary significantly due to market conditions, the quality and location of production and other risk factors. We cannot accurately predict oil and natural gas differentials and premiums. Increases in the differential and decreases in the premium between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

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 or results of operations. 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 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; 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 82% of our net productive oil and natural gas wells, which represents 88% of our proved developed producing reserves as of December 31, 2017. 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.

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies do, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

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 may be disproportionately 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 and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such

arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

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:

- 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. 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 financial condition and results of operations.

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 disposal 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 in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, 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 previously released materials or property 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 and regulations or for personal injury or property damage. 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.

President Trump has indicated that he would work to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue or any new legislation Congress may pass with the goal of reducing environmental statutory or regulatory requirements may be challenged in court. In addition, various state laws and regulations (and permits issued thereunder) will be unaffected by federal changes unless and until the state laws and corresponding permits are similarly changed, and any judicial review is completed.

Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. 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 regards 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 EPA announced in 2015 that it would directly regulate methane emissions from oil and natural gas wells for the first time as part of President Obama s Climate Action Plan. As part of this strategy, in May 2016, the EPA issued three final rules. The EPA issued a final rule that updated the New Source Performance Standards to add requirements that the oil and gas industry reduce emissions of greenhouse gases and to cover additional equipment and activities in the oil and gas production chain. The final rule sets emissions limits for methane, which is the principal greenhouse gas emitted by equipment and processes in the oil and gas sector. This rule applies to new, reconstructed and modified processes and equipment. This rule also expands the volatile organic compound emissions limits to hydraulically fractured oil wells and equipment used across the industry that was not regulated in the 2012 rules. The rule also requires owners and operators to find and repair leaks, also known as fugitive emissions. The EPA also issued a final rule known as the Source Determination Rule, which is intended to clarify when multiple pieces of equipment and activities in the oil and gas industry must be deemed a single source when determining whether major source permitting programs apply under the prevention of significant deterioration, nonattainment new source review preconstruction and operation permit programs under Title V of the CAA (Title V). The final rule defines the term adjacent to clarify that equipment and activities in the oil and gas sector that are under common control will be considered part of the same source if they are located near each other specifically, if they are located on the same site, or on sites that share equipment and are within one quarter of a mile of each other. This rule applies to equipment and activities used for onshore oil and natural gas production, and for natural gas processing. It does not apply to offshore operations. Finally, the EPA also issued a final Federal Implementation Plan (FIP) for Indian country, which implements the minor new source review program in Indian country for oil and natural gas production. The FIP will be used instead of site-specific minor new source review preconstruction permits in Indian country and incorporates emissions limits and other requirements from eight federal air standards, including the final New Source Performance Standard, subpart OOOOa. Requirements of the FIP apply throughout Indian country, except non-reservation areas, unless a tribe or the EPA demonstrates jurisdiction for those areas.

Compliance with such 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 with air permits or other requirements of the CAA and associated state laws and regulations.

In 2016, the EPA also issued the first draft of an Information Collection Request, seeking a broad range of information on the oil and gas industry, including: how equipment and emissions controls are, or can be, configured, what installing those controls entails and the associated costs. This includes information on natural gas venting that occurs as part of existing processes or maintenance activities, such as well and pipeline blowdowns, equipment malfunctions and flashing emissions from storage tanks.

In June 2017, the EPA proposed staying the final rule implementing certain of the new oil and gas standards for two years while it reconsiders the rules. In November 2017, the EPA issued a notice of data availability for the proposed stay of the rules, with a comment period closing on December 8, 2017.

We are currently engaged in discussions with the Colorado Department of Public Health and Environment (the CDPHE) concerning certain equipment used in our Redtail facilities and our compliance with various air permits and applicable federal and state air quality laws and regulations over the control of air pollutant emissions from those facilities. We and the CDPHE are negotiating the terms of a settlement agreement to resolve this matter.

Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents could result in higher operating costs, which could in turn adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as those of the oil and gas industry in general.

Climate change legislation or regulations restricting emissions of greenhouse gases 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, including rules that limit emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect in January 2011. In June 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (the PSD) and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining best available control technology standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis.

In June 2014, the Supreme Court upheld most of the EPA s GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. 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 accordance with President Obama s Climate Action Plan, 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. Each state is given a different carbon reduction target, but the EPA expects that, in the aggregate, the overall proposal will reduce carbon emissions from electric generating units by 32% from 2005 levels. States are given substantial flexibility in meeting their emission reduction targets and can generally choose to lower carbon emissions by replacing higher carbon generation, such as coal or natural gas, with lower carbon generation, such as efficient natural gas units or renewable energy alternatives. Several industry groups and states have challenged the Clean Power Plan in the Court of Appeals for the D.C. Circuit, and in February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan while it is being challenged in court. The Court of Appeals for the D.C. Circuit heard oral arguments on the Clean Power Plan in September 2016, but has not yet issued a decision. On March 28, 2017, the Trump Administration issued an executive order directing the EPA to review the Clean Power Plan. On the same day, the EPA filed a motion in the U.S. Court of Appeals for the D.C. Circuit requesting that the court hold the case in

abeyance while the EPA conducts its review of the Clean Power Plan. On October 16, 2017, the EPA published a proposed rule that would repeal the Clean Power Plan. The EPA also stated in the proposed rule that the agency has not determined the scope of any rule to regulate GHG emissions from existing electric generating units, but intends to issue an Advance Notice of Proposed Rulemaking in the near future. Several states have already announced their intention to challenge any repeal of the Clean Power Plan. It is not yet clear what changes, if any, will result from the EPA s proposal, whether or how the courts will rule on the legality of the Clean Power Plan, the EPA s repeal of the rules, or any future replacement.

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. In the absence of new legislation, the EPA is issuing new regulations that limit emissions of GHG associated with our operations which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil, NGLs and natural gas that we produce. 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.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful exploration, development and production activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. 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 economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production.

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 R. DeBoer, Senior Vice President, General Counsel and Corporate Secretary; Peter W. Hagist, Senior Vice President, Planning and Reservoir Engineering; Rick A. Ross, Senior Vice President, Operations; Michael J. Stevens, Senior Vice President and Chief Financial Officer; Steven A. Kranker, Vice President, Business Development; or David M. Seery, Vice President, Land, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

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 or to obtain external funding on terms acceptable to us.

Competition in the oil and gas industry 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 for. 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.

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 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 and would not take effect until 12 months after the date of enactment. 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 cyber security attacks could significantly disrupt our business operations.

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. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to our information systems could lead to data corruption, communication interruption or otherwise significantly disrupt our business operations.

Risks related to the exchange offer and new notes

You may have difficulty selling the original notes that you do not exchange.

If you do not exchange your original notes for the new notes offered in the exchange offer, then you will continue to be subject to the restrictions on transfer of your original notes. Those transfer restrictions are described in the indenture governing the original notes and in the legend contained on the original notes, and arose because we originally issued the original notes under exemptions from, and in transactions not subject to, the registration requirements of the Securities Act.

In general, you may offer or sell your original notes only if they are registered under the Securities Act and applicable state securities laws, or if they are offered and sold under an exemption from those requirements. We do not intend to register the original notes under the Securities Act.

If a large number of original notes are exchanged for new notes issued in the exchange offer, then it may be more difficult for you to sell your unexchanged original notes. In addition, if you do not exchange your original notes in the exchange offer, then you will no longer be entitled to have those original notes registered under the Securities Act.

See The Exchange Offer Consequences of failure to exchange original notes for a discussion of the possible consequences of failing to exchange your original notes.

You must carefully follow the required procedures to exchange your original notes.

The new notes will be issued in exchange for original notes only after timely receipt by the exchange agent of a duly executed letter of transmittal (or an agent s message (as defined under The Exchange Offer Procedures for tendering original notes)) and all other required documents. Therefore, if you wish to tender your original notes, you must allow sufficient time to ensure timely delivery. Neither we nor the exchange agent has any duty to notify you of defects or irregularities with respect to tenders of original notes for exchange. Any holder of original notes who tenders in the exchange offer for the purpose of participating in a distribution of the new notes will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction. Each broker-dealer that receives new notes for its own account in exchange for original notes that were acquired in market-making or other trading activities must acknowledge that it will deliver a prospectus in connection with any resale of the new notes.

Late deliveries of original notes and other required documents could prevent a holder from exchanging its original notes.

Holders are responsible for complying with all exchange offer procedures. The issuance of new notes in exchange for original notes will only occur upon completion of the procedures described in this prospectus under The Exchange Offer. Therefore, holders of original notes who wish to exchange them for new notes should allow sufficient time for timely completion of the exchange procedure. Neither we nor the exchange agent are obligated to extend the offer, notify you of any failure to follow the proper procedure or waive any defect if you fail to follow the proper procedure.

If you are a broker-dealer, your ability to transfer the new notes may be restricted.

A broker-dealer that purchased original notes for its own account as part of market-making or trading activities must comply with the prospectus delivery requirements of the Securities Act when it sells the new notes. Our obligation to make this prospectus available to broker-dealers is limited. Consequently, we cannot guarantee that a proper prospectus will be available to broker-dealers wishing to resell their new notes.

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 March 31, 2018, we and the guarantors had $90 million in borrowings and $2 million in letters of credit outstanding under the prior credit agreement, with $2.2 billion of available borrowing capacity (which was subsequently reduced to $1.7 billion in connection with entering into the amended and restated Credit Agreement on April 12, 2018), as well as $2.3 billion of senior notes and $562 million of the convertible notes outstanding. We are allowed to incur additional indebtedness, provided that we meet certain requirements in the indentures governing our senior notes and the Credit Agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- 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 the Credit Agreement and the indentures governing our 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;

- 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 the 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

- when oil and natural gas prices decline, our ability to maintain compliance with our financial covenants becomes more difficult and our borrowing base is subject to reductions, 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. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on the Credit Agreement is redetermined on May 1 and November 1 of each year, and may be the subject of special redeterminations described in the 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 remain at their current levels for a prolonged period or go lower, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the Credit Agreement.

We may not have sufficient funds to make such repayments, including the new notes. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, issuances of debt securities and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including the Credit Agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock or debt securities, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

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 the Credit Agreement and the holders of the new notes and our other senior notes could declare all outstanding principal and interest to be due and payable, and the lenders under the Credit Agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings and we could be forced into bankruptcy or liquidation. 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 financial position and results of operations. Further, failing to comply with the financial and other restrictive covenants in the Credit Agreement and the indentures governing our senior notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

Despite our current debt levels, we may still incur substantially more debt or take other actions which would intensify the risks discussed above.

Despite our current consolidated debt levels, we and our subsidiaries may be able to incur substantial additional debt in the future in connection with our exploration, development and production activities. Although the indentures governing our senior notes contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of qualifications and exceptions, and the additional indebtedness incurred in compliance with these restrictions could be substantial. If we incur any additional indebtedness that ranks equally with the new notes, subject to collateral arrangements, the holders of that debt will be entitled to share ratably with you in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of our company. This may have the effect of reducing the amount of proceeds paid to you. These restrictions also will not prevent us from incurring obligations that do not constitute indebtedness. In addition, as of March 31, 2018, we and the guarantors had $90 million in borrowings and $2 million in letters of credit outstanding, with the ability to incur an additional $2.2 billion (which was subsequently reduced to $1.7 billion in connection with entering into the amended and restated Credit Agreement on April 12, 2018). All of those borrowings would be secured indebtedness. If new debt is incurred in addition to our current debt levels, the related risks that we and the guarantors now face could intensify. See Description of Other Material Indebtedness and Description of New Notes.

Servicing our debt and our significant capital expenditure requirements requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial debt.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness, including the new notes, and to make planned capital expenditures depends on our future performance, which is subject to economic, financial, competitive, legislative, regulatory and other factors beyond our control, including the price we receive for oil and natural gas. Our business may not continue to generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations.

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 the Credit Agreement contain various restrictive covenants that may limit our management s discretion in certain respects. In particular, these agreements will limit our and our subsidiaries ability to, among other things:

- pay dividends or make other distributions or repurchase or redeem our capital stock;

prepay, redeem or repurchase certain debt;

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.

The Credit Agreement contains various 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. These restrictions apply to all of our restricted subsidiaries (as defined in the Credit Agreement). 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.

If we fail to comply with the restrictions in the indentures governing our senior notes or the Credit Agreement, the restrictions that will be in the indentures that will govern the new notes, or the restrictions in any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, 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 the 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.

The new notes are effectively subordinated to our secured debt and the secured debt of the subsidiary guarantors of the new notes.

The new notes will not be secured by our or any of the subsidiary guarantors assets. As a result, the new notes and the guarantees will effectively be subordinated to any of our secured indebtedness and the secured indebtedness of our subsidiaries guaranteeing the new notes to the extent of the value of the collateral securing such indebtedness. In the event of our or any guarantor s bankruptcy, liquidation, reorganization or other winding up, our assets or the assets of the guarantor, as applicable, that secure our secured debt will be available to pay obligations on the new notes and guarantees only after the secured debt has been repaid in full from these assets. There may not be sufficient assets remaining to pay amounts due on any or all of the new notes and guarantees then outstanding.

As a holding company, we rely on payments from our subsidiaries in order for us to make payments on the new notes.

We are a holding company with no significant operations of our own. Because our operations are conducted through our wholly-owned subsidiaries, we depend on dividends, advances and other payments from our subsidiaries in order to allow us to satisfy our financial obligations. Our subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to us, whether by dividends, advances or other payments. Unless they are guarantors of the new notes, our subsidiaries do not have any obligation to pay amounts due under our indebtedness or to make funds available for that purpose. Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the new notes. The ability of our subsidiaries to pay dividends and make other payments to us depends on their earnings, capital requirements and general financial conditions and is restricted by, among other things, the Credit Agreement, applicable corporate and other laws and regulations as well as agreements to which our subsidiaries may be a party. While the indentures governing our senior notes and the Credit Agreement will limit the ability of certain of our subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to qualifications and exceptions. In the event that we do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the new notes. Although certain subsidiaries are guaranteeing the new notes, the guarantees are effectively subordinated to all of our subsidiaries secured debt, including the indebtedness under the Credit Agreement to the extent of the value of the collateral securing such debt.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Interest under the Credit Agreement accrues on a floating rate basis such that interest rate changes will impact future results of operations and cash flows. If interest rates were to increase, our debt service obligations on our Credit Agreement would increase even though the amount borrowed remained the same, and our net income and cash flows, including cash available for servicing our indebtedness, will correspondingly decrease. At March 31, 2018, the Company and the guarantors had $90 million in borrowings and $2 million in letters of credit outstanding under the Credit Agreement, and the weighted average interest rate on the outstanding principal balance was 3.9%. In the future, we may enter into interest rate swaps that involve the exchange of floating for fixed rate interest payments in order to reduce interest rate volatility. However, we may not maintain interest rate swaps with respect to all of our variable rate indebtedness, and any swaps we enter into may not fully mitigate our interest rate risk.

We may not be able to repurchase the new notes upon a change of control and your rights upon a change of control may be limited.

Upon the occurrence of certain change of control events followed by a rating decline within 90 days as specified in the indenture, holders of the new notes may require us to repurchase all or any part of their notes. The occurrence of these same change of control events would also obligate us to offer to repurchase our existing senior notes. We may not have sufficient funds at the time of the change of control to make the required repurchases of the new notes. Additionally, certain events that would constitute a change of control (as defined in the indenture) would constitute an event of default under the Credit Agreement that would, if it should occur, permit the lenders to accelerate the debt outstanding under such Credit Agreement and that, in turn, would cause an event of default under the indenture. We would not be permitted to repurchase the new notes prior to termination of and payment in full of the obligations under the Credit Agreement.

The source of funds for any repurchase required as a result of any change of control will be our available cash or cash generated from oil and gas operations or other sources, including borrowings, sales of assets, sales of equity or funds provided by a new controlling entity. We cannot assure you, however, that sufficient funds would be available at the time of any change of control to make any required repurchases of the new notes or our existing senior notes tendered and to repay debt under the Credit Agreement. Furthermore, using available cash to fund the potential consequences of a change of control may impair our ability to obtain additional financing in the future. Any future credit agreements or other agreements relating to debt to which we may become a party will most likely contain similar restrictions and provisions.

Recent Delaware court decisions have held that the continuing director element of the definition of change of control may be interpreted by the courts in a manner that permits the board of directors of a Delaware

corporation to approve a slate of directors proposed by a third party in a hostile proxy contest for the purposes of avoiding triggering a change of control under an indenture, even where the board of directors has actively opposed the election of such directors. As such, the ability of holders to require us to offer to purchase their notes as a result of a successful hostile proxy contest for our board of directors may be limited.

In addition, some important corporate events, such as leveraged recapitalizations, may not, under the indentures governing the new notes and our other senior notes constitute a change of control that would require us to repurchase the new notes or our existing senior notes, even though those corporate events could increase the level of our indebtedness or otherwise adversely affect our capital structure, credit ratings or the value of the new notes. See Description of New Notes Repurchase at the option of holders Change of control triggering event.

Holders of the new notes may not be able to determine when a change of control giving rise to their right to have the new notes repurchased has occurred following a sale of substantially all of our assets.

One of the circumstances under which a change of control may occur is upon the sale or disposition of all or substantially all of our assets. There is no precise established definition of the phrase substantially all under applicable law and the interpretation of that phrase will likely depend upon particular facts and circumstances. Accordingly, the ability of a holder of new notes to require us to repurchase its new notes as a result of a sale of less than all our assets to another person may be uncertain.

Any new note guarantees of the new notes may be subordinated or avoided by a court.

Initially, each of our subsidiaries that is an obligor or guarantor under the Credit Agreement and our other senior notes will guarantee the new notes. In the future, the new notes will be guaranteed by each material domestic subsidiary of the Company and each restricted subsidiary of the Company that is a borrower or a guarantor under the Credit Agreement or that incurs or guarantees certain capital markets indebtedness. See Description of New Notes Subsidiary guarantees. These new note guarantees will be joint and several obligations of the guarantors.

Federal and state fraudulent transfer and conveyance statutes may apply to the issuance of the new notes and the incurrence of the guarantees of the new notes. Under federal bankruptcy law and comparable provisions of state fraudulent transfer or conveyance laws, which vary from state to state, the new notes or the guarantees thereof could be voided as a fraudulent transfer or conveyance if we or any of the guarantors, as applicable:

- issued the new notes or incurred the guarantees with the intent to hinder, delay or defraud creditors or that we or such subsidiary guarantor, as applicable, contemplated insolvency with a design to favor one or more creditors to the total or partial exclusion of others; or

- did not receive fair consideration or reasonably equivalent value for issuing the new notes or the guarantee, as applicable, and, at the time of issuance of the new notes or the guarantee, as applicable, we or the applicable subsidiary guarantor:

    - was insolvent or rendered insolvent by reason of the issuance of the new notes or the new note guarantee, as applicable;

was engaged or about to engage in a business or transaction, such as payment of consideration, for which the remaining assets of us or the subsidiary guarantor, as applicable, constituted an unreasonably small amount of capital to carry on our or its business, respectively; or

intended to incur, or believed that it would incur, debts beyond our or its ability, respectively, to pay such debts as they matured.

If a court were to find that the issuance of the new notes or the incurrence of a guarantee was a fraudulent transfer or conveyance, the court could void the payment obligations under the new notes or that guarantee, could subordinate the new notes or that guarantee to presently existing and future indebtedness of ours or of the related guarantor, or could require the holders of the new notes to repay any amounts received with respect to the new notes or that guarantee. In the event of a finding that a fraudulent transfer or conveyance has occurred, you may not receive any repayment on the new notes. Further, the avoidance of the new notes could result in an event of default with respect to our and our subsidiaries other debt that could result in acceleration of that debt.

As a general matter, value is given for a transfer or an obligation if, in exchange for the transfer or obligation, property is transferred or an antecedent debt is secured or satisfied. A debtor will generally not be considered to have received value in connection with a debt offering if the debtor use