WHITING PETROLEUM CORP
Form 10-K
February 23, 2017
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

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

For the fiscal year ended December 31, 2016

or

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

For the transition period from _______________ to _______________

Commission file number: 001 31899

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

Delaware (State or other jurisdiction of incorporation or organization)	20 0098515 (I.R.S. Employer Identification No.)
	80290 2300

1700 Broadway, Suite 2300
Denver, Colorado
(Address of principal executive offices) (Zip code)

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

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

Common Stock, $0.001 par value	New York Stock Exchange
(Title of Class)	(Name of each exchange on which registered)

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

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

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Act. Yes No

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

Aggregate market value of the voting common stock held by non-affiliates of the Registrant at June 30, 2016: $3,357,000,000.

Number of shares of the Registrant's common stock outstanding at February 15, 2017: 362,698,464 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2017 Annual Meeting of Stockholders are incorporated by reference into Part III.

TABLE OF CONTENTS

Table of Contents

glossary of Certain Definitions

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

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

“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.

“CO2” Carbon dioxide.

“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.

“delay rental” Consideration paid to the lessor by a lessee to extend the terms of an oil and natural gas lease in the absence of drilling operations and/or production that is contractually required to hold the lease. This consideration is generally required to be paid on or before the anniversary date of the oil and gas lease during its primary term, and typically extends the lease for an additional year.

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

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

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

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

“EOR” Enhanced oil recovery.

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

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

“FASB” Financial Accounting Standards Board.

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

Table of Contents

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

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

“ISDA” International Swaps and Derivatives Association, Inc.

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

“LIBOR” London interbank offered rate.

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

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

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

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

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

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

“MMcf/d” One MMcf per day.

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

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

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“PDNP” Proved developed nonproducing reserves.

“PDP” Proved developed producing reserves.

“plug-and-perf technology” A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the casing perforations into the formation within that stage.

“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 the footnote to the Proved Reserves table in Item 1. “Business” of this Annual Report on Form 10-K for more information.

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

“SEC” The United States Securities and Exchange Commission.

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

“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.

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

Table of Contents

PART I

Item 1. Business

Overview

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

Since our inception, we have built a strong asset base through a combination of property acquisitions, development of proved reserves and exploration activities. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties, such as the acquisition of Kodiak Oil & Gas Corp. (the "Kodiak Acquisition") discussed in the "Acquisitions and Divestitures" footnote in the notes to the consolidated financial statements. As a result of lower crude oil prices during 2015 and 2016, we significantly reduced our level of capital spending to more closely align with our cash flows generated from operations, and have focused our drilling activity on projects that provide the highest rate of return. 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 the asset sales discussed below under "Acquisitions and Divestitures".

As of December 31, 2016, our estimated proved reserves totaled 615.5 MMBOE and our 2016 average daily production was 129.9 MBOE/d, which results in an average reserve life of approximately 12.9 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2016, their corresponding pre-tax PV10% values, and our fourth quarter 2016 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2016:

	Proved Reserves (1)						
Core Area	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value (2) (in millions)	4th Quarter 2016 Average Daily Production (MBOE/d)
Northern Rocky Mountains (3)	281.9	81.8	522.3	450.8	63%	$ 2,397	108.9
Central Rocky Mountains (4)	109.3	19.6	191.2	160.7	68%	285	9.2
Other (5)	3.6	0.1	2.2	4.0	90%	16	0.8
Total	394.8	101.5	715.7	615.5	64%	$ 2,698	118.9

Discounted Future Income Tax Expense (6)	-
Standardized Measure of Discounted Future Net Cash Flows	$ 2,698

____

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from an oil price of $42.75 per Bbl and a gas price of $2.49 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, 2016 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

Table of Contents

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, North Dakota, Texas and Wyoming.
(6) Based on the 12-month average oil and natural gas prices used in the computation of pre-tax PV10% as of December 31, 2016, our future net income generated over the life of our proved reserves is expected to be less than our net operating loss carryforward deductions and therefore, under the Standardized Measure, there is no deduction for federal or state income taxes.

During 2016, we incurred $554 million in exploration and development ("E&D") expenditures, including $504 million for the drilling of 89 gross (48.2 net) wells. All of these new wells resulted in productive completions.

Our current 2017 E&D budget is $1.1 billion, which we expect to fund substantially with net cash provided by our operating activities, proceeds from property divestitures, cash on hand, borrowings under our credit facility or by accessing the capital markets. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our E&D budget accordingly, enter into agreements with industry partners, divest certain oil and gas property interests, adjust borrowings outstanding under our credit facility or access the capital markets as necessary.

Acquisitions and Divestitures

During 2015 and 2016, in response to sustained lower crude oil prices, we divested of a large number of non-core oil and gas properties that no longer matched the profile of properties we desire to own. In addition, in January 2017 we closed on the sale of our interests in two gas processing plants located in the Williston Basin for aggregate sales proceeds of $375 million. Refer to the "Subsequent Events" footnote in the notes to consolidated financial statements for more information on this transaction. Our significant acquisitions and divestitures during the last two years are summarized below.

Acquisitions. There were no significant acquisitions during the years ended December 31, 2016 and 2015.

2016 Divestitures. In July 2016, we completed the sale of our interest in our enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including our interest in certain CO2 properties in the McElmo Dome field in Colorado and certain other related assets and liabilities (the "North Ward Estes Properties") for a cash purchase price of $300 million (before closing adjustments). The sale was effective July 1, 2016 and resulted in a pre-tax loss on sale of $187 million. In addition to the cash purchase price, the buyer has agreed to pay us $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million (the "Contingent Payment"). The Contingent Payment will be made at the option of the buyer either in cash on July 31, 2018 or in the form of a secured promissory note, accruing interest at 8% per annum with a maturity date of July 29, 2022. The North Ward Estes Properties consisted of estimated proved reserves of 120.3 MMBOE as of December 31, 2015, representing 15% of our proved reserves as of that date, and generated 8.6 MBOE/d (or 6%) of our June 2016 average daily net production.

2015 Divestitures. In December 2015, we completed the sale of a fresh water delivery system, a produced water gathering system and four saltwater disposal wells located in Weld County, Colorado, effective December 16, 2015, for aggregate sales proceeds of $75 million (before closing adjustments).

In June 2015, we completed the sale of our interests in certain non-core oil and gas wells, effective June 1, 2015, for aggregate sales proceeds of $150 million (before closing adjustments) resulting in a pre-tax loss on sale of $118 million. The properties included over 2,000 gross wells in 132 fields across 10 states. The properties had estimated proved reserves of 20.9 MMBOE as of December 31, 2014, representing 3% of our proved reserves as of that date, and generated 5.3 MBOE/d (or 3%) of our May 2015 average daily production.

In April 2015, we completed the sale of our interests in certain non-core oil and gas wells, effective May 1, 2015, for aggregate sales proceeds of $108 million (before closing adjustments) resulting in a pre-tax gain on sale of $29 million. The properties are located in 187 fields across 14 states, and predominately consisted of assets that were previously included in the underlying properties of Whiting USA Trust I. The properties had estimated proved reserves of 8.9 MMBOE as of December 31, 2014, representing 1% of our total proved reserves as of that date, and generated 2.7 MBOE/d (or 2%) of our March 2015 average daily net production.

Also during the year ended December 31, 2015, we completed several immaterial divestiture transactions for the sale of our interests in certain non-core oil and gas wells and undeveloped acreage, for aggregate sales proceeds of $176 million (before closing adjustments) resulting in a pre-tax gain on sale of $28 million. These properties had estimated proved reserves of 23.4 MMBOE as of December 31, 2014, representing 3% of our total proved reserves as of that date. The properties generated a combined total of approximately 4.4 MBOE/d of average daily net production, based on production rates at each of the respective closing dates.

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 large resource plays such as our Williston Basin and Denver Julesburg Basin (“DJ Basin”) projects has become one of our central objectives. As of December 31, 2016, we have assembled approximately 736,000 gross (443,800 net) developed and undeveloped acres in the Williston Basin located in North Dakota and Montana. As of December 31, 2016, we had four drilling rigs operating in this area. During 2016, we entered into two separate wellbore participation agreements related to wells drilled in the Williston Basin, which helped allow us to continue completion activity in this area.

At our Redtail field in the DJ Basin in Weld County, Colorado, we have assembled approximately 157,200 gross (132,200 net) developed and undeveloped acres. As of December 31, 2016, we had one drilling rig operating in the DJ Basin. We suspended completion operations in this area beginning in the second quarter of 2016; however, we plan to resume completion activity in early 2017. 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.

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 equity and debt issuances, bank borrowings, internally generated cash flows and certain oil and gas property divestitures, as appropriate, to maintain our financial position. As a result of sustained lower crude oil prices in 2015 and 2016, we significantly reduced our level of capital spending to more closely align with our cash flows generated from operations, and have focused our drilling activity on projects that provide the highest rate of return. 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 2015 and 2016 we sold a large number of non-core oil and gas properties that no longer matched the profile of properties we desire to own. In addition, to support cash flow generation on our existing properties and help ensure expected cash flows from newly acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars, swaps and crude oil sales and delivery contracts to provide an attractive base commodity price level. As of January 3, 2017, we had derivative contracts covering the sale of approximately 49% of our forecasted 2017 oil production.

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, such as the Kodiak Acquisition, which closed in 2014 and significantly expanded our presence in the Williston Basin.

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, 2016, we had interests in 4,687 gross (1,917 net) productive wells on approximately 849,300 gross (517,200 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 12.9 years based on year-end 2016 proved reserves and 2016 production.

Experienced Management and Technical Teams. Our management team averages 30 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.

Table of Contents

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 9,400 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 2017, while also testing new diversion technology and more efficient placement and drillout of down-hole plugs.

Proved Reserves

Our estimated proved reserves as of December 31, 2016 are summarized by core area in the table below. See “Reserves” in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

	Oil (MMBbl)	NGLs (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (1) (in millions)
Northern Rocky Mountains (2):						
PDP	168.1	49.4	314.5	270.0	60%	
PDNP	0.9	0.3	2.0	1.5	-%	
PUD	112.9	32.1	205.8	179.3	40%	
Total proved	281.9	81.8	522.3	450.8	100%	$ 1,847.7
Central Rocky Mountains (3):						
PDP	10.2	2.0	18.6	15.2	10%	
PDNP	0.4	0.1	0.6	0.6	-%	
PUD	98.7	17.5	172.0	144.9	90%	
Total proved	109.3	19.6	191.2	160.7	100%	$ 1,753.9
Other (4):						
PDP	3.2	0.1	1.6	3.6	90%	
PDNP	0.4	0.0	0.6	0.4	10%	

Total proved	3.6	0.1	2.2	4.0	100%	$ 4.3
Total Company:						
PDP	181.5	51.5	334.7	288.8	47%	
PDNP	1.7	0.4	3.2	2.5	-%	
PUD	211.6	49.6	377.8	324.2	53%	
Total proved	394.8	101.5	715.7	615.5	100%	$ 3,605.9

(1) Estimated future capital expenditures incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.
(2) Includes oil and gas properties located in Montana and North Dakota.
(3) Includes oil and gas properties located in Colorado.
(4) Primarily includes non-core oil and gas properties located in Colorado, Mississippi, New Mexico, North Dakota, Texas and Wyoming.

Table of Contents

Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked or transported by rail to terminals, market hubs, refineries or storage facilities. The tables below present percentages by purchaser that accounted for 10% or more of our total oil, NGL and natural gas sales for the years ended December 31, 2016 and 2014. For the year ended December 31, 2015, no individual purchaser accounted for 10% or more of our total oil, NGL and natural gas sales. We believe that the loss of any individual purchaser would not have a long-term material adverse impact on our financial position or results of operations, as alternative customers and markets for the sale of our products are readily available in the areas in which we operate.

Year Ended December 31, 2016:	
Tesoro Crude Oil Co	15%
Jamex Marketing LLC	12%

Year Ended December 31, 2014:	
Plains Marketing LP	17%
Shell Trading US	10%
Bridger Trading LLC	10%

Title to Properties

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

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

Competition

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

Regulation

Regulation of Production

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

Currently, none of our total production volumes are produced from offshore leases, however, some of our prior offshore operations were conducted on federal leases that are administered by the Bureau of Ocean Energy Management (the “BOEM”). The present value of our future abandonment obligations associated with offshore properties was $38 million as of December 31, 2016. We are therefore required to comply with the regulations and orders issued by the BOEM under the Outer Continental Shelf Lands Act.

Table of Contents

Among other things, we are required to obtain prior BOEM approval for any exploration plans we pursue and for our lease development and production plans. BOEM regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases.

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

Regulation of Sale and Transportation of Oil

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

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

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

Public protests and media attention related to permitting and construction of the Dakota Access Pipeline in North Dakota near the Standing Rock Indian Reservation may attract additional attention to oil pipeline operations and regulation. We do not expect any resulting impacts to oil pipeline transportation would affect our operations in any way that is of material difference from those of our competitors.

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

A portion of our crude oil production may be shipped to market centers using rail transportation facilities owned and operated by third parties. The DOT and PHMSA establish safety regulations relating to crude-by-rail transportation. In addition, third-party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the DOT, the Federal Railroad Administration (the "FRA") of the DOT, the Occupational Safety and Health Administration and other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to regulate movement of hazardous materials in ways not preempted by federal law.

Table of Contents

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

In February 2014, the DOT issued an emergency order requiring all persons to ensure crude oil is properly tested and classed prior to offering such product into transportation, and to assure all shipments by rail of crude oil be handled as a Packing Group I or II hazardous material. Also in February 2014, the Association of American Railroads entered into a voluntary agreement with the DOT to implement certain restrictions around the movement of crude oil by rail. In May 2014 (and extended indefinitely in May 2015), the DOT issued an Emergency Restriction/Prohibition Order requiring each railroad carrier operating trains transporting 1,000,000 gallons or more of Bakken crude oil to provide notice to state officials regarding the expected movement of the trains through the counties in each state. The PHMSA and FRA have also issued safety advisories and alerts regarding oil transportation and have issued a report focused on the increased volatility and flammability of Bakken crude oil as compared with other crudes in the U.S. In May 2015, PHMSA issued new rules applicable to “high-hazard flammable trains”, defined as a continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed throughout a train. Among other requirements, the new rules require enhanced braking systems, enhanced standards for newly constructed tank cars and retrofitting of existing tank cars, restricted operating speeds, a documented testing and sampling program, and routine assessments that evaluate 27 safety and security factors. In December 2015, the Fixing America's Surface Transportation (“FAST”) Act became law, further extending PHMSA’s authority to improve the safety of transporting flammable liquids by rail and pursuant to which new regulations phasing out the use of certain older rail cars were finalized in August 2016. In June 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety (“PIPES”) Act of 2016 became law. The PIPES Act strengthens PHMSA’s safety authority, including an expansion of its ability to issue emergency orders, which were adopted by rule in October 2016. PHMSA continues to review further potential new safety regulations under the PIPES Act and the FAST Act.

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

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

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

Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the

FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

The FERC implements the Outer Continental Shelf Lands Act pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access and non-discriminatory transportation service. One of the FERC's principal goals in carrying out this Act's mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in the markets in which our natural gas is sold. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. In addition, the natural gas industry historically has always been heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Table of Contents

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

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

In October 2015, a failure at an underground natural gas storage facility in Southern California prompted PHMSA to issue an advisory bulletin reminding owners and operators of underground storage facilities to review operations, identify the potential for facility leaks and failures, and to review and update emergency plans. The State of California proclaimed the underground natural gas storage facility an emergency situation in January 2016. A federal task force was also convened to make recommendations to help avoid such failures. An interim final rule of PHMSA became effective in January 2017 addressing design issues for underground storage facilities, including wells, wellbore tubing and casing. Any further increased attention to and requirements for underground storage safety and infrastructure by state and federal regulators that may result from this incident will not affect us in a way that materially differs from the way it affects other natural gas producers.

Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences; restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities; limit or prohibit project siting, constru