NORTHERN OIL & GAS, INC.
Form 10-K
March 02, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K
(Mark One)

ý 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 No. 001-33999

____

NORTHERN OIL AND GAS, INC.
(Exact Name of Registrant as Specified in Its Charter)

Minnesota	95-3848122
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

601 Carlson Pkwy – Suite 990, Minnetonka, Minnesota 55305
(Address of Principal Executive Offices) (Zip Code)
952-476-9800
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	NYSE MKT

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 ý

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

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 ý 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 ý No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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 small 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 ý	Non-Accelerated Filer (Do not check if a smaller reporting company)	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 ý

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sale price as reported by the NYSE MKT) was approximately $208.7 million.

As of February 28, 2017, the registrant had 63,251,197 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the registrant's 2017 Annual Meeting of Shareholders are incorporated by reference into Part III of this report for the year ended December 31, 2016.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "s words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: changes in crude oil and natural gas prices, the pace of drilling and completions activity on our properties, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which our company conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, our ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting our company's operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in "Item 1A. Risk Factors" and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. We assume no obligation to update any forward-looking statements in order to reflect any event or circumstance that may arise after the date of this report, other than as may be required by applicable law or regulation. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the United States Securities and Exchange Commission (the "SEC") which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of crude oil and natural gas:

“Bbl.” One stock tank barrel of 42 U.S. gallons liquid volume used herein in reference to crude oil, condensate or NGLs.

“Boe.” A barrel of oil equivalent and is a standard convention used to express oil, NGL and natural gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.

“Boepd.” Boe per day.

“Btu or British Thermal Unit.” The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

“MBbl.” One thousand barrels of crude oil, condensate or NGLs.

“MBoe.” One thousand Boes.

“Mcf.” One thousand cubic feet of natural gas.

“MMBbl.” One million barrels of crude oil, condensate or NGLs.

“MMBoe.” One million Boes.

“MMBtu.” One million British Thermal Units.

“MMcf.” One million cubic feet of natural gas.

“NGLs.” Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

“Basin.” A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“Completion.” The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

“Conventional play.” An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"Developed acreage." Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"Development well." A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

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

"Exploratory well." A well drilled to find and produce crude oil, NGLs, or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil, NGLs, or natural gas in another reservoir, or to extend a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differs from nearby rock.

"Gross acres or Gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

"Held by operations." A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"Held by production." A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"Hydraulic fracturing." The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"Infill well." A subsequent well drilled in an established spacing unit to the addition of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"Net acres." The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"Net well." A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"NYMEX." The New York Mercantile Exchange.

"OPEC." The Organization of Petroleum Exporting Countries.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Recompletion." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"Unconventional play." An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

"Undeveloped acreage." Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Wellbore." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"West Texas Intermediate or WTI." A light, sweet blend of oil produced from the fields in West Texas.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Terms used to assign a present value to or to classify our reserves:

"Possible reserves." The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"Pre-tax PV-10% or PV-10." The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"Probable reserves." The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"Proved developed producing reserves (PDPs)." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved developed non-producing reserves (PDNPs)." Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"Proved reserves." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences 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.

"Proved undeveloped drilling location." A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"Proved undeveloped reserves" or "PUDs." 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 development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not 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 tests in the area and in the same reservoir or an analogous reservoir.

(i) The area of the reservoir considered as proved includes: (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil, NGLs or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

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

"Standardized measure." Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

NORTHERN OIL AND GAS, INC.

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NORTHERN OIL AND GAS, INC.

ANNUAL REPORT ON FORM 10-K
FOR FISCAL YEAR ENDED DECEMBER 31, 2016
PART I
Item 1. Business

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. We believe the location, size and concentration of our acreage position in one of North America's leading unconventional oil-resource plays will provide drilling and development opportunities that result in significant long-term value. Our primary focus is oil exploration and production through non-operated working interests in wells drilled and completed in spacing units that include our acreage. As a non-operator, we are able to diversify our investment exposure by participating in a large number of gross wells, as well as entering into more project areas by partnering with numerous experienced operating partners. In addition, because we can elect to participate on a well-by-well basis, we believe we have increased flexibility in the timing and amount of our capital expenditures because we are not burdened with various contractual development agreements or a large operating support staff. Further, we are able to avoid exploratory costs incurred by many oil and gas producers.

During 2016, we added 294 gross (10.7 net) wells in the Williston Basin. At December 31, 2016, we owned working interests in 2,914 gross (213.1 net) producing wells, consisting of 2,911 wells targeting the Bakken and Three Forks formations and three wells targeting other formations. As of December 31, 2016, we leased approximately 155,016 net acres, all located in the Williston Basin, of which approximately 121,938 net acres were developed.

As of December 31, 2016, our proved reserves were 54.1 MMBoe (all of which were in the Williston Basin) as estimated by our third-party independent reservoir engineering firm, Ryder Scott Company, LP. As of December 31, 2016, 70% of our proved reserves were classified as proved developed and 86% of our proved reserves were oil. The following table provides a summary of certain information regarding our assets:

	As of December 31, 2016						
	Net Acres	Productive Wells		Average Daily Production[1] (Boe per day)	Proved Reserves (MBoe)	% Oil	% Proved Developed
		Gross	Net				
North Dakota	135,110	2,820	202.2	13,404	53,505	86	69
Montana	19,906	94	10.9	249	576	83	100
Total	155,016	2,914	213.1	13,653	54,081	86	70

(1) Represents the average daily production over the twelve months ended December 31, 2016.

Due to the significant reduction in oil and gas commodity prices that has persisted since late 2014, development activity has substantially declined and we have significantly reduced our capital spending over the past two years. Nonetheless, we believe that we can enhance value for our shareholders with our disciplined approach to capital allocation and other efforts to strengthen our liquidity and financial position.

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Business Strategy

Key elements of our business strategies include:

- Deploy our Capital in a Conservative and Strategic Manner and Review Opportunities to Bolster our Liquidity. In the current industry environment, maintaining liquidity is critical. Therefore, we will be highly selective in the projects that we fund and will review opportunities to bolster our liquidity and financial position through various means.

- Continue Participation in the Development of Our Existing Properties in the Williston Basin as a Non-Operator. In the current price environment, we believe the best way to develop our acreage is to take a long-term approach and develop our locations with potential for the highest rates of return. We plan to continue to concentrate our capital expenditures in the Williston Basin, where we believe our current acreage position can provide an attractive return on the capital employed on our multi-year drilling inventory of oil-focused properties.

- Diversify Our Risk Through Non-Operated Participation in a Large Number of Bakken and Three Forks Wells. As a non-operator, we seek to diversify our investment and operational risk through participation in a large number of oil wells and with multiple operators. As of December 31, 2016, we have participated in 2,914 gross (213.1 net) producing wells in the Williston Basin with an average working interest of 7.3% in each gross well, with more than 35 experienced operating partners. We expect to continue partnering with numerous experienced operators across our leasehold positions.

- Evaluate and Pursue Value-Enhancing Acquisitions, Joint Ventures and Divestitures. We will continue to monitor the market for strategic acquisitions that we believe could be accretive and enhance shareholder value. We generally seek to acquire small lease positions at a significant discount to the contiguous acreage positions typically sought by larger producers. As part of this strategy, we consider areas that are actively being drilled and permitted and where we have an understanding of the operators and their drilling plans, capital requirements and well economics. In addition, we have increasingly taken interest in and will continue to evaluate the acquisition of non-operated producing properties as a means to grow and/or bolster our credit metrics.

- Maintain a Strong Balance Sheet and Proactively Manage to Limit Downside. We strive to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. Given the low commodity price environment existing at December 31, 2016 and continuing into 2017, Northern intends to preserve liquidity by remaining selective on capital deployment. We employ an active commodity price risk management program to better enable us to execute our business plan over the entire commodity price cycle. The following table summarizes the open oil derivative contracts that we have entered into as of December 31, 2016:

Open Contracts

Year	Swap Volumes (Bbl)	Weighted Average Swap Price ($)	Costless Collar Volumes (Bbl)	Weighted Average Floor/Ceiling Prices ($)
2017[1]	2,525,000	52.55	300,000	50.00 / 60.06
2018	813,000	54.40	—	—
2019 and beyond	—	—	—	—

(1) The Company has entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 10,000

barrels per month are exercisable on or about June 30, 2017. If the counterparties exercise all such options, the notional volume of the Company's existing crude oil derivative contracts would increase by 10,000 barrels per month at an average price of $55.20 per barrel for each month during the period July 1, 2017 through December 31, 2017.

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Industry Operating Environment

The oil and natural gas industry is affected by many factors that we generally cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. Significant factors that will impact oil prices in the current fiscal year and future periods include: political and social developments in the Middle East, demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Additionally, natural gas prices continue to be under pressure due to concerns over excess supply of natural gas due to the high productivity of emerging shale plays in the United States. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Oil and natural gas prices have fallen significantly since their early third quarter 2014 levels and NYMEX WTI oil prices dropped to the $26 per Bbl level in February 2016. Although oil prices have increased since February 2016, they remain well below the $100 per Bbl oil prices realized during 2014. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

While lower commodity prices will reduce our future net cash flow from operations, we expect to have sufficient liquidity to continue development of our oil and gas properties. In 2016, our capital spending was decreased by 34% as compared to 2015 and our cash flows exceeded our development expenditures, which allowed us to reduce our credit facility borrowings by $6 million. At December 31, 2016, the borrowing base on our credit facility was $350 million and there was a $144 million outstanding balance, leaving $206 million of borrowing capacity under the facility. Although our borrowing base could be reduced if commodity prices do not improve, we believe our borrowing base has resilience since 85% of our pre-tax PV-10 consists of producing properties which do not require material maintenance capital expenditures to maintain forecasted production levels. If the existing commodity price environment persists and prices remain lower-for-longer, we plan to continue development within available cash flows and potentially seek the acquisition of producing properties to offset decline as sufficient liquidity allows.

Development

We primarily engage in oil and natural gas exploration and production by participating on a proportionate basis alongside third-party interests in wells drilled and completed in spacing units that include our acreage. In addition, from time-to-time, we acquire working interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in particular well proposals. We typically depend on drilling partners to propose, permit and initiate the drilling of wells. Prior to commencing drilling, our partners are required to provide all owners of oil, natural gas and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling opportunity on a case-by-case basis and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas, expected oil and gas prices, expertise of the operator, and completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, the recent significant decline in oil prices has reduced both the number of well proposals we receive and the proportion of well proposals in which we have elected to participate.

We do not manage our commodities marketing activities internally, but our operating partners generally market and sell oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil production from our wells to appropriate pipelines or rail transport facilities pursuant to arrangements that such partners negotiate and maintain with various parties purchasing the production. We understand that our partners generally sell our production to a variety of purchasers at prevailing market prices under separately negotiated short-term contracts. The price at which production is sold generally is tied to the spot market for oil. Williston Basin Light Sweet Crude from the Bakken source rock is generally 41-42 API crude oil and is readily accepted into the pipeline infrastructure. The weighted average differential reported to us by our producers during 2016 was $8.25 per barrel below NYMEX pricing. Our weighted average differential was approximately $7.46 per barrel below NYMEX pricing during the fourth quarter of 2016. This differential represents the imbedded transportation costs in moving the oil from wellhead to refinery and will fluctuate based on availability of pipeline, rail and other transportation methods.

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Competition

The oil and natural gas industry is intensely competitive, and we compete with numerous other oil and natural gas exploration and production companies. Some of these companies have substantially greater resources than we have. Not only do they explore for and produce oil and natural gas, but also many carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. The operations of other companies may be able to pay more for exploratory prospects and productive oil and natural gas properties. They may also have more resources to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Our larger or integrated competitors may be better able to absorb the burden of existing, and any changes to federal, state, and local laws and regulations than we can, which would adversely affect our competitive position. Our ability to discover reserves and acquire additional properties in the future will be dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, we may be at a disadvantage in producing oil and natural gas properties and bidding for exploratory prospects, because we have fewer financial and human resources than other companies in our industry. Should a larger and better financed company decide to directly compete with us, and be successful in its efforts, our business could be adversely affected.

Marketing and Customers

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

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a variety of exploration and production companies, from large publicly-traded companies to small, privately-owned companies. We do not believe the loss of any single operator would have a material adverse effect on our company as a whole.

Title to Properties

Our oil and natural gas properties are subject to customary royalty and other interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured 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 title to or rights in our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title only when we acquire producing properties or before commencement of drilling operations.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt the drilling and producing activities of our operating partners and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operating partners and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operating partners' operations.

Principal Agreements Affecting Our Ordinary Business

We do not own any physical real estate, but, instead, our acreage is comprised of leasehold interests subject to the terms and provisions of lease agreements that provide our company the right to drill and maintain wells in specific geographic areas. Lease arrangements that comprise our acreage positions are generally established using industry-standard terms that have been established and used in the oil and natural gas industry for many years. Some of our leases may be acquired from other parties that obtained the original leasehold interest prior to our acquisition of the leasehold interest.

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In general, our lease agreements stipulate three-to-five year terms. Bonuses and royalty rates are negotiated on a case-by-case basis consistent with industry standard pricing. Once a well is drilled and production established, the leased acreage in the applicable spacing unit is considered developed acreage and is held by production. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production. Given the current pace of drilling in the Bakken play at this time, we do not believe lease expiration issues will materially affect our North Dakota position.

Governmental Regulation and Environmental Matters

Our operations are subject to various rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole.

Regulation of Oil and Natural Gas Production

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota and Montana require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, both states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“FERC”) and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. 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 transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On December 17, 2015, the FERC established a new price index for the five-year period which commenced on July 1, 2016.

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 who are similarly situated.

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 similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

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Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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 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. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;
- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from its operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA") and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Recent regulation and litigation that has been brought against others in the industry under RCRA concern liability for earthquakes that were allegedly caused by injection of oil field wastes.

The Endangered Species Act ("ESA") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of ESA. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations are in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify our operations or could force discontinuation of certain operations altogether.

On April 17, 2012, the U.S. Environmental Protection Agency (the "EPA") finalized rules proposed on July 28, 2011 that establish new air emission controls under the Clean Air Act ("CCA") for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards ("NSPS") for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. On August 5, 2013, the EPA issued final updates to its 2012 VOC performance standards for storage tanks. The rules establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules revise leak detection requirements for natural gas processing plants. These rules may require a number of modifications to the operations of our third-party operating partners, including the installation of new equipment to control emissions from compressors.

On September 18, 2015, the EPA proposed to further amend the NSPS for the oil and natural gas source category to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas-processing and transmission sources. These regulations were finalized and published in the Federal Register on June 3, 2016. Although we cannot predict the cost to comply with these new requirements at this point, compliance with these new rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

These new regulations and proposals and any other new regulations requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Substantially all of the oil and natural gas production in which we have interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act to address hydraulic fracturing operations.

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Scrutiny of hydraulic fracturing activities continues in other ways. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. Several states, including Montana and North Dakota where our properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. New York State's ban on hydraulic fracturing was recently upheld by the Courts. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, which could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. Many of the activities of our third-party operating partners are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews and on March 12, 2012, issued final guidance that may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

Significant studies and research have been devoted to climate change, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production.

In the United States, legislative and regulatory initiatives are underway to limit greenhouse gas ("GHG") emissions. The U.S. Congress has considered legislation that would control GHG emissions through a "cap and trade" program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act, or the CAA, definition of an "air pollutant." In response the EPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. In 2010, the EPA issued a final rule, known as the "Tailoring Rule," that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. On June 23, 2014, the U.S. Supreme Court in Utility Air Regulatory Group v. EPA held that the EPA's "Tailoring Rule" was invalid, but held that if a source was subject to Prevention of Significant Deterioration ("PSD") or Title V based on emissions of conventional pollutants like sulfur dioxide, particulates, nitrogen dioxide, carbon monoxide, ozone or lead, then the EPA could also require the source to control GHG emissions and the source would have to install Best Available Control Technology to do so. As a result, a source no longer is required to meet PSD and Title V permitting requirements based solely on its GHG emissions, but may still have to control GHG emissions if it is an otherwise regulated source.

On February 23, 2014, Colorado became the first state in the nation to adopt rules to control methane emissions from oil and gas facilities. On June 3, 2016, EPA issued three final rules that were intended to curb emissions of methane, VOCs and toxic air pollutants such as benzene from new, reconstructed and modified oil and gas sources. These new regulations include leak detection and repair provisions, and may require controls to reduce methane emissions from certain oil and gas facilities. To the extent our third party operating partners are required to further control methane emissions, such controls could impact our business.

In addition, in September 2009, the EPA issued a final rule requiring the reporting of GHGs from specified large GHG emission sources in the United States beginning in 2011 for emissions in 2010. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. Our third party operating partners are required to report their greenhouse gas emissions under these rules. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Moreover, while the U.S. Supreme Court held in its June 2011 decision American Electric Power Co. v. Connecticut that, with respect to claims concerning GHG emissions, the federal common law of nuisance was displaced by the federal Clean Air Act, the Court left open the question of whether tort claims against sources of GHG emissions alleging property damage may proceed under state common law. There thus remains some litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

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Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Although operators may take steps to mitigate physical risks from storms, no assurance can be given that future storms will not have a material adverse effect on our business.

Employees

We currently have 19 full time employees. We may hire additional technical or administrative personnel as appropriate. However, we do not expect a significant change in the number of full time employees over the next 12 months based upon our currently-projected business plan. We are using and will continue to use the services of independent consultants and contractors to perform various professional services. We believe that this use of third-party service providers enhances our ability to contain general and administrative expenses.

Office Locations

Our executive offices are located at 601 Carlson Pkwy, Suite 990, Minnetonka, Minnesota 55305. Our office space consists of 8,295 square feet of leased space. We believe our current office space is sufficient to meet our needs for the foreseeable future.

Organizational Background

Our company took its present form on March 20, 2007, when Northern Oil and Gas, Inc. (“Northern”), a Nevada corporation engaged in our current business, merged with and into our subsidiary, with Northern remaining as the surviving corporation (the “Merger”). Northern then merged into us, and we were the surviving corporation. We then changed our name to Northern Oil and Gas, Inc. As a result of the Merger, Northern was deemed to be the acquiring company for financial reporting purposes and the transaction was accounted for as a reverse merger. Our primary operations are now those formerly operated by Northern as well as other business activities since March 2007.

On June 30, 2010, we reincorporated in the State of Minnesota from the State of Nevada pursuant to a plan of merger between Northern Oil and Gas, Inc., a Nevada corporation, and Northern Oil and Gas, Inc., a Minnesota corporation and wholly-owned subsidiary of the Nevada corporation. Upon the reincorporation, each outstanding certificate representing shares of the Nevada corporation’s common stock was deemed, without any action by the holders thereof, to represent the same number and class of shares of our company’s common stock. As of June 30, 2010, the rights of our shareholders began to be governed by Minnesota corporation law and our Minnesota articles of incorporation and bylaws.

Available Information – Reports to Security Holders

Our website address is www.northernoil.com. We make available on this website, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. These filings are also available to the public at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Electronic filings with the SEC are also available on the SEC internet website at www.sec.gov.

We have also posted to our website our Audit Committee Charter, Compensation Committee Charter, Nominating Committee Charter and our Code of Business Conduct and Ethics, in addition to all pertinent company contact information.

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Item 1A. Risk Factors

Oil and natural gas prices are volatile. The continuing and extended decline in oil and natural gas prices has adversely affected, and could continue to adversely affect, our business, financial position, results of operations and cash flow.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Oil and natural gas prices declined significantly and have remained depressed since late 2014. The prices we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. We seek to mitigate volatility and potential declines in oil prices through derivative arrangements that hedge a portion of our expected production. However, the future protection provided by our derivative activities is significantly lower now than it was last year. As of December 31, 2016, we had hedged 2.5 million barrels of oil in 2017 at an average price of $52.55 per barrel and approximately 0.8 million barrels of oil in 2018 at an average price of $54.40 per barrel and derivative costless collar contracts hedging approximately 0.3 million barrels of oil in 2017 with a floor price of $50.00 and a ceiling price of $60.06 (see Note 13 to our financial statements).

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of OPEC and other major oil producing 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;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- changes in U.S. energy policy under the current administration;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- 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; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices have and, if they continue, will continue to decrease our revenues, the amount of oil and natural gas that our operators can produce economically, and our reserve bookings. A substantial or extended decline in oil or natural gas prices, such as the depressed commodity price environment that we've experienced since late 2014, has resulted in and could result in further future impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Even if the increases in prices experienced at the start of 2017 continue, it may be insufficient to offset the effect of the prior decreases. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Although oil and natural gas prices have shown slight increases, we expect that the lower oil and natural gas prices could reduce the amount of our borrowing base under our revolving credit facility, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders and is subject to redetermination from time to time as provided in our credit agreement.

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Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating, exploration and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history, and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business and preparing reports to our lenders and investors. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, development schedules, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, reserve engineers and other advisors to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGLs we ultimately recover being different from our reserve estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and subsequent reports we file with the SEC. For example, the estimated quantities and value of our proved reserves as of December 31, 2016 declined significantly from the prior year, due to the decline in oil and natural gas prices as well as a reduction in the number of undeveloped locations included in our proved reserve estimates, due to reduced levels of drilling in a low commodity price environment. In addition, we may adjust estimates of net proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and any other factors, many of which are beyond our control.

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

Our operators' drilling activities are subject to many risks, including the risk that they will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations on our acreage may be curtailed, delayed or canceled by our operators as a result of other factors, including:

- declines in oil or natural gas prices;
- the high cost, shortages or delivery delays of equipment and services;
- shortages of or delays in obtaining water for hydraulic fracturing operations;
- unexpected operational events;

- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- regulations, restrictions, moratoria and bans on hydraulic fracturing;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;

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- formations with abnormal pressures;

- environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;

- fires;

- blowouts, craterings and explosions;

- uncontrollable flows of oil, natural gas or well fluids; and

- pipeline capacity curtailments.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Due to the sustained decrease in oil and natural gas prices, we have taken significant writedowns of our oil and natural gas properties. If oil or natural gas prices remain sufficiently depressed, we may be required to record further writedowns of our oil and natural gas properties.

In 2015 and 2016 we were required to write down the carrying value of certain of our oil and natural gas properties, and further writedowns could be required in the future. Writedowns may occur when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, an impairment would be recognized.

During 2016, we performed an impairment review using prices that reflect an average of 2016‘s monthly prices as prescribed pursuant to the SEC’s guidelines. As a result, during 2016 we recorded $237.0 million in impairment. The average prices used in the December 31, 2016 impairment review are lower than the currently forecasted prices for 2017. If lower average monthly pricing is reflected in the trailing twelve-month average pricing calculation, the present value of our future net revenues could decline and additional impairment could be recognized. Although oil and natural gas prices have shown slight increases, if a lower pricing environment reoccurs we expect we could be required to further write down the value of our oil and gas properties. The quarterly ceiling test considers many factors including reserves, capital expenditure estimates and trailing twelve-month average prices. SEC defined prices for each quarter in 2016 were as follows:

SEC Defined Prices for 12 Months Ended	NYMEX Oil Price (per Bbl)	Henry Hub Gas Price (per MMBtu)
December 31, 2016	$ 42.75	$ 2.49
September 30, 2016	41.68	2.28
June 30, 2016	43.12	2.24
March 31, 2016	46.26	2.39

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Any significant reduction in our borrowing base under our revolving credit facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our revolving credit facility is currently subject to a borrowing base of $350 million. The borrowing base is subject to scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the revolving credit facility. The lenders under our revolving credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in crude oil, NGL and natural gas reserve engineering;
- increased operating and/or capital costs;
- the lenders’ inability to agree to an adequate borrowing base; or
- adverse changes in the lenders’ practices (including required regulatory changes) that affect reserves-based lending.

As of December 31, 2016, we had $144 million of borrowings outstanding under our revolving credit facility. We may make further borrowings under our revolving credit facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our future success depends on our ability to replace reserves that our operators produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We may acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both proved and producing properties as well as undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all of these properties will contain economically viable reserves or that we will not abandon our initial investments. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on our properties will be productive or that we will recover all or any portion of our investments in our properties and reserves.

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As a non-operator, our development of successful operations relies extensively on third-parties, which could have a material adverse effect on our results of operation.

We have only participated in wells operated by third-parties. Our current ability to develop and maintain successful business operations depends on the success of our third-party operators. If our operators are not successful in the development, exploitation, production and exploration activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operation would be materially adversely affected.

These risks are heightened in the current low commodity price environment, which we expect will present significant challenges to most (if not all) of our operators. The challenges and risks faced by our operators may be similar to or greater than our own, including with respect to their ability to service their debt, remain in compliance with their debt instruments and, if necessary, access additional capital. We have already seen some bankruptcy filings for oil and gas operators, and the current low commodity price environment could result in additional operators being forced into bankruptcy. The insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator's breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations to other owners of working interests), which may not be in our best interests.

Additionally, we may have virtually no ability to exercise influence over the operational decisions of our operators, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on our operators could prevent us from realizing our target returns for those locations. The success and timing of development activities by our operators will depend on a number of factors that will largely be outside of our control, including:

- oil and natural gas prices and other factors generally affecting industry operating environment;

- the timing and amount of capital expenditures;

- their expertise and financial resources;

- approval of other participants in drilling wells;

- selection of technology; and

- the rate of production of reserves, if any.

We could experience periods of higher costs as activity levels in the Williston Basin fluctuate or if commodity prices rise. These increases could reduce our profitability, cash flow, and ability to complete development activities as planned.

The recent decline in commodity prices has decreased activity and investment in the Williston Basin. However, if and when activity in the Williston Basin increases, competition for equipment, labor and supplies is also expected to increase. Likewise, higher oil, natural gas and NGL prices generally increase the demand for equipment, labor and supplies, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our operating partners' ability to drill the wells and conduct the operations that we currently expect.

In addition, capital and operating costs in the oil and natural gas industry have generally risen during periods of increasing commodity prices as producers seek to increase production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds commodity price inflation, our profitability and cash flow, and our operators' ability to complete development activities as scheduled and on budget, may be negatively impacted. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available to make payments on our debt obligations.

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Our lack of industry and geographical diversification may increase the risk of an investment in our company.

Our business focus is on the oil and natural gas industry in a limited number of properties that are primarily in the areas of the Williston Basin located in Montana and North Dakota. While other companies may have the ability to manage their risk by diversification, the narrow focus of our business, in terms of both the industry focus and geographic scope of our business, means that we will likely be impacted more acutely by factors affecting our industry or the region in which we operate than we would if our business were more diversified. As a result of the narrow focus of our business, we may be disproportionately exposed to the effects of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of oil or natural gas. Additionally, we may be exposed to further risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the Williston Basin. We do not currently intend to broaden either the nature or geographic scope of our business.

Locations that the operators of our properties decide to drill may not yield oil or natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if the operators of our properties drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If the operators of our properties drill future wells that are identified as dry holes, the drilling success rate would decline and may adversely affect our results of operations.

To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the price of oil, we enter into derivative instrument contracts for a portion of our expected oil production, including swaps, collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our balance sheet as assets or liabilities and in our statements of operations as gain (loss) on derivatives, net. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments. Although our 2016 hedges provided us with a significant benefit as they were generally priced above the then-current prices for oil, given the current commodity price environment, it is highly unlikely that we will be able to put new hedges in place that will provide us with similar benefit.

Our derivatives activities could result in financial losses or could reduce our cash flow.

We enter into swaps, collars or other derivatives arrangements from time to time to hedge our expected production depending on projected production levels and expected market conditions. While intended to mitigate the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- a counterparty to our derivative contracts is unable to satisfy its obligations under the contracts;
- our production is less than expected; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement.

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Our net operating loss carryforwards may be limited under Section 382 of the Internal Revenue Code by certain changes in the ownership of our company.

We have net operating loss ("NOL") carryforwards that we may use to offset against taxable income for U.S. federal income tax purposes. At December 31, 2016, we had an estimated NOL carryforward of approximately $605.4 million for United States federal tax return purposes. However, Section 382 of the Internal Revenue Code of 1986, as amended, may limit the NOLs that we may use in any year for U.S. federal income tax purposes in the event of certain changes in ownership of our company. Any limitation on our ability to use NOLs could, depending on the extent of such limitation, result in higher U.S. federal income taxes being paid (and therefore a reduction in cash) than if such NOLs were available as an offset against such income for U.S. federal income tax reporting purposes. In addition, if the limitation under Section 382 is triggered, it could result in a significant charge to earnings in the period in which it is triggered.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using a 12-month average price and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- the volume, pricing and duration of our oil and natural gas hedging contracts;
- actual prices we receive for oil, natural gas and NGLs;
- our actual operating costs in producing oil, natural gas and NGLs;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our business depends on oil and natural gas transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, physical damage, scheduled maintenance or other reasons, could result in a substantial increase in costs, the shut-in of producing wells or the delay or discontinuance of development plans for our properties. The negative effects arising from these and similar circumstances may last for an extended period of time. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, many of our wells are drilled in locations in the Williston Basin that are serviced only to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third party oil trucking to transport a significant portion of our production to third party transportation pipelines, rail loading facilities and other market access points. Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established or operations are commenced on units containing the acreage or the leases are extended.

A significant portion of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to participate in the development of the related properties. Drilling plans for these areas are generally in the discretion of third party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third party approvals; oil, NGL and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2016, we estimate that we had leases that were not developed that represented 14,873 net acres potentially expiring in 2017, 10,736 net acres potentially expiring in 2018, 4,483 net acres potentially expiring in 2019 and 2,986 net acres potentially expiring in 2020 and beyond.

Seasonal weather conditions adversely affect operators' ability to conduct drilling activities in the areas where our properties are located.

Seasonal weather conditions can limit drilling and producing activities and other operations in our operating areas and as a result, a majority of the drilling on our properties is generally performed during the summer and fall months. These seasonal constraints can pose challenges for meeting well drilling objectives and increase competition for equipment, supplies and personnel during the summer and fall months, which could lead to shortages and increase costs or delay operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to jobsites due to the muddy conditions caused by spring thaws. This could limit access to jobsites and operators' ability to service wells in these areas.

Significant capital expenditures are required to develop our properties and replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our credit facility, debt issuances, and equity issuances. We have also engaged in asset sales from time to time. If our access to capital were limited due to numerous factors, which could include a decrease in operating cash flow due to lower oil and natural gas prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to develop our properties and replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset sales or access other methods of financing on acceptable terms to develop our properties and/or meet our reserve replacement requirements.

The amount available for borrowing under our credit facility is subject to a borrowing base which is determined by our lenders, at their discretion, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in oil and natural gas prices have adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. Oil and natural gas prices have fallen significantly since their early third quarter 2014 levels. For example, oil prices declined from $105.34 per Bbl on July 1, 2014 to $53.72 per Bbl on December 31, 2016, while natural gas prices have declined from $4.46 per Mcf to $3.72 per Mcf over the same period. If commodity prices (particularly oil prices) remain, it could have adverse effects on our reserves and borrowing base and reduce our ability to replace our reserves.

We may be unable to obtain additional capital that we will require to implement our business plan.

Future acquisitions and future exploration, development, production and marketing activities, will require a substantial amount of capital. Cash reserves, cash from operations and borrowings under our revolving credit facility may not be sufficient to fund both our continuing operations and our planned growth. We may require additional capital to continue to grow our business through acquisitions and to further expand our exploration and development programs. We may be unable to obtain additional capital if and when required.

We may pursue sources of additional capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be successful in consummating suitable financing transactions in the time period required or at all, and we may not be able to obtain the capital we require by other means. If the amount of capital we are able to raise from financing activities, together with our cash from operations, is not sufficient to satisfy our capital requirements, we may not be able to implement our business plan and may be required to scale back our operations, sell assets at unattractive prices or obtain financing on unattractive terms, any of which could adversely affect our business, results of operations and financial condition.

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The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 30% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2016. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.

We have expanded our operations in part through acquisitions. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

Any acquisition involves other potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs;
- a decrease in our liquidity by using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- dilution to shareholders if we use equity as consideration for, or to finance, acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes.

The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely could diminish our ability to conduct our operations, and harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of those members of our management team whose knowledge, relationships with industry participants, leadership and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on our management team's knowledge and expertise in the industry. To continue to develop our business, we rely on our management team's knowledge and expertise in the industry and will use our management team's relationships with industry participants to enter into strategic relationships, which may take the form of joint ventures with other private parties and contractual arrangements with other oil and natural gas companies.

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The members of our management team may terminate their employment with our company at any time. If we were to lose members of our management team, we may not be able to replace the knowledge that they possess. In addition, we may not be able to establish or maintain strategic relationships with industry participants. If we were to lose the services of the members of our management team, our ability to conduct our operations and execute our business plan could be materially harmed.

Deficiencies of title to our leased interests could significantly affect our financial condition.

We typically do not incur the expense of a title examination prior to acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights have been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value or be eliminated. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights may be lost. It is generally our practice not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we typically rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion. Furthermore, title issues may arise at a later date that were not initially detected in any title review or examination. Any one or more of the foregoing could require us to reverse revenues previously recognized and potentially negatively affect our cash flows and results of operations. Our failure to obtain perfect title to our leaseholds may adversely affect our current production and reserves and our ability in the future to increase production and reserves.

Competition may limit our ability to obtain rights to explore and develop oil and natural gas reserves.

The oil and natural gas industry is highly competitive. Other oil and natural gas companies may seek to acquire oil and natural gas leases and other properties and services we will need to operate our business in the areas in which we expect to operate. This competition is increasingly intense as prices of oil and natural gas on the commodities markets have risen in recent years. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies which, in particular, may have access to greater resources, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. If we are unable to compete effectively or respond adequately to competitive pressures, our results of operation and financial condition may be materially adversely affected.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. Although additional Williston Basin transportation takeaway capacity has been added over the last several years, production also increased substantially during the same period. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities has caused price differentials to significantly increase at times.

Crude oil from the Bakken/Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

The U.S. Department of Transportation ("USDOT") recently concluded that crude oil from the Bakken/Three Forks formations has a higher volatility than most other U.S. crude oil and thus is more ignitable and flammable. Based on that information, and several fires involving rail transportation of crude oil, USDOT has started a rulemaking to develop new requirements for shipping crude oil by rail. In addition, the rail industry has adopted increased precautions for crude shipments. Any new restrictions that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

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Our business involves the selling and shipping by rail of crude oil, including from the Bakken shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our crude oil production is transported to market centers by rail. Recent derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable materials. Transportation safety regulators in the United States and Canada are concerned that crude oil from the Bakken shale may be more flammable than crude oil from other producing regions and are investigating that issue and are also considering changes to existing regulations to address those possible risks. In May 2015, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted a final rule that, among other things, imposes a new and enhanced tank car design standard for certain tank cars carrying crude oil and ethanol, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as routing analyses, speed restrictions and enhanced braking controls. Transport Canada has also issued legal requirements that align with the rule adopted by PHMSA, including standards relating to train speed restrictions, route risk analyses and a phase out of non-compliant DOT-111 tank cars.

Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport 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 United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

To the extent that new regulations require design changes or other modifications of tank cars, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our insurance policies will cover the entirety of any damages that may arise from such an event.

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

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

Our derivative activities expose us to potential regulatory risks.

The Federal Trade Commission ("FTC"), Federal Regulatory Commission ("FERC") and the Commodities Futures Trading Commission ("CFTC") have statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to derivative activities that we undertake with respect to oil, natural gas, NGLs, or other energy commodities, we are required to observe the market-related regulations enforced by these agencies. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

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Legislative and regulatory developments could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

In July of 2010, the United States Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”), which contains measures aimed at increasing the transparency and stability of the over-the-counter (“OTC”) derivatives market and preventing excessive speculation. In November 2013, the CFTC re-proposed implementing regulations imposing position limits for certain physical commodity contracts in the major energy markets and economically equivalent futures, options and swaps, with exemptions for certain bona fide hedging positions. The CFTC’s initial position limit rules were vacated by a federal court in 2012. It is not clear when the newly-proposed rules on position limits would become effective. CFTC rules under the Dodd-Frank Act also may impose clearing and trade execution requirements in connection with our derivatives activities, although currently those requirements do not extend to derivatives based on physical commodities in the energy markets and some or all of our derivatives activities may be exempt from such requirements based on our non-financial end-user status.

Regulations issued under the Dodd-Frank Act also may require certain counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules are being phased in over time depending on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The legislation and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. We maintain an active hedging program related to oil price risks. The Dodd-Frank Act and rules and regulations thereunder could reduce trading positions and the market-making activities of our counterparties. If we reduce our use of derivatives as a result of legislation and regulations or any resulting changes in the derivatives markets, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures or to make payments on our debt obligations. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our business is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operational interests, as operated by our third-party operating partners, are regulated extensively at the federal, state, tribal and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, our company (either directly or indirectly through our operating partners) could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our business and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we do business includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our business and limit the quantity of natural gas we may produce and sell. A major risk inherent in the drilling plans in which we participate is the need for our operators to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the development of our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff.

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Environmental risks may adversely affect our business.

All phases of the oil and natural gas business can present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. There is risk of incurring significant environmental costs and liabilities as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our business, and historical operations and waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the imposition of injunctive relief.

Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge, regardless of whether we were responsible for the release or contamination and regardless of whether our operating partners met previous standards in the industry at the time they were conducted. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of operations on our properties. The application of environmental laws to our business may cause us to curtail production or increase the costs of our production, development or exploration activities.

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

Hydraulic fracturing is used extensively by our third-party operating partners. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act (the “SDWA”) regulates the underground injection of substances through the Underground Injection Control (“UIC”) program. While hydraulic fracturing generally is exempt from regulation under the UIC program, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program as “Class II” UIC wells. On October 21, 2011, the EPA announced its intention to propose federal Clean Water Act regulations governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the Department of Interior (“DOI”) published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on Federal and Indian lands, including requirements for disclosure, well bore integrity and handling of flowback water. The final rule was issued on March 26, 2015.

The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. The EPA issued a Progress Report in December 2012. In March 2013, the EPA’s Scientific Advisory Board (“SAB”) formed an ad hoc panel of experts who are reviewing the Progress Report on the study. The draft assessment was released for public comment and peer review on June 5, 2015 and a final assessment was released in December 2016 generally concluding that hydraulic fracturing activities can impact drinking water resources in some circumstances and identifying factors that can influence the impacts. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress may consider similar SDWA legislation in the future.

On August 16, 2012, the EPA published final regulations under the Clean Air Act ("CAA") that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA promulgated New Source Performance Standards ("NSPS") establishing emission limits for sulfur dioxide (SO2) and volatile organic compounds (VOCs). The final rule requires a 95% reduction in VOCs emitted by mandating the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Until this date, emissions from fractured and refractured gas wells must be reduced through reduced emission completions or combustion devices. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration of these rules from both industry and the environmental community and court challenges to the final rules, the EPA announced its intention to issue revised rules in 2013. The EPA published revised portions of these rules on September 23, 2013 for VOC emissions for production oil and gas storage tanks, in part phasing in emissions controls on storage tanks past October 15, 2013. On December 19, 2014, the EPA published updates to its NSPS for the oil and gas industry. The most recent proposed update to the oil and gas NSPS came on June 3, 2016, when the EPA finalized further amendments that address methane emissions from certain oil and gas facilities.

In addition, several state and local governments are considering or have adopted legislative or regulatory restrictions on hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For example, Montana and North Dakota have both adopted regulations recently requiring the disclosure of all fluids, additives, and chemicals used in the hydraulic fracturing process. And, in 2014, North Dakota adopted new requirements aimed at capturing gas and reducing flaring.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. If new laws or regulations that significantly restrict hydraulic fracturing, such as amendments to the SDWA, are adopted, such laws could make it more costly for us and difficult for our third party operating partners to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our third-party operating partners fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs.

Any such federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operating partners could have a material adverse effect on our financial condition and results of operations. Until such pending or threatened legislation or regulations are finalized and implemented, it is not possible to estimate their impact on our business.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

The EPA has determined that emissions of certain “greenhouse gases” (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act (the “CAA”). On September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule to include certain petroleum and natural gas facilities, which rule requires data collection beginning in 2011 and reporting beginning in 2012. Our operating partners were required to report certain of their greenhouse gas emissions under this rule by September 28, 2012. On May 12, 2010, the EPA also issued a “tailoring” rule, which makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the CAA. On June 23, 2014, the U.S. Supreme Court in Utility Air Regulatory Group v. EPA held that the EPA’s “Tailoring Rule” was invalid, but held that if a source was subject to PSD or Title V based on emissions of conventional pollutants like sulfur dioxide, particulates, nitrogen or dioxide, carbon monoxide, ozone and lead, then the EPA could also require the source to control GHGS and would have to install Best Available Control Technology to do so. As a result, a source no longer is required to meet PSD and Title V permitting requirements based solely on its GHG emissions. On February 23, 2014, Colorado became the first state in the nation to adopt rules to control methane emissions from Colorado oil and gas facilities. Subsequently, the Obama administration has approved rules that would require controls on methane emissions from oil and gas facilities. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the October 23, 2015, promulgation of emission guidelines for GHG emissions from existing electric utility generating units (the "Clean Power Plan"). This plan requires states to regulate carbon dioxide emissions from utility operations, with a long-term goal of 30% reduction below 2005 rates of CO2 from electric utilities by the year 2030. An expected outcome of this plan is that use of coal as a main fuel source for electric utilities would be replaced by use of lower-emitting products, including natural gas and wind and solar energy. Implementation of the Clean Power Plan is currently stayed pending court review. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

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In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, though it is yet to do so, and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG reduction goal. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require our third-party operating partners, and indirectly us, to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas produced by our operational interests. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations.

Regulation of GHG emissions could also result in reduced demand for our production, as oil and natural gas consumers seek to reduce their own GHG emissions. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could have a material adverse effect on our business, results of operations and financial condition. In addition, to the extent climate change results in more severe weather and significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic effects, our own, our third-party operating partners or our customers' operations may be disrupted, which could result in a decrease in our available products or reduce our customers' demand for our products.

Further, there have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (i) shift more power generation to renewable energy sources and (ii) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGL consumption.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We accrue a liability for decommissioning costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our revolving credit agreement contains operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit agreement contains, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- declare or pay any dividend or make any other distributions on, purchase or redeem our equity interests or purchase or redeem subordinated debt;
- make certain investments;
- incur or guarantee additional indebtedness or issue certain types of equity securities;
- create certain liens;
- sell assets;
- consolidate, merge or transfer all or substantially all of our assets; and

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- engage in transactions with our affiliates.

In addition, as of December 31, 2016, we were required to maintain a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0, a ratio of secured debt to EBITDAX (as defined in the credit agreement) of no greater than 2.5 to 1.0 and a ratio of EBITDAX (as defined in the credit agreement) to interest expense (as defined in the credit agreement) of no less than 1.75 to 1.0 (through December 31, 2016). The minimum ratio of EBITDAX to interest expense that we are required to maintain begins stepping down with the quarter ending December 31, 2016, through the quarter ending March 31, 2018 (See Note 4 to our financial statements). As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the foregoing covenants and restrictions may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit agreement or any future indebtedness could result in an event of default under our revolving credit agreement or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our revolving credit agreement occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;

- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;

- may have the ability to require us to apply all of our available cash to repay these borrowings; and

- may prevent us from making debt service payments under our other agreements.

An event of default or an acceleration under our revolving credit agreement could result in an event of default and an acceleration under other existing or future indebtedness, including our senior notes. Conversely, an event of default or an acceleration under any other existing or future indebtedness could result in an event of default and an acceleration under our revolving credit agreement. In addition, our obligations under the revolving credit agreement are collateralized by perfected first priority liens and security interests on substantially all of our assets and if we are unable to repay our indebtedness under the revolving credit agreement, the lenders could seek to foreclose on our assets.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;

- increase our vulnerability to economic downturns and adverse developments in our business, such as the current low commodity price environment;

- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and

- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations.

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Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We depend on our revolving credit facility for future capital needs, because we use operating cash flows for investing activities and borrow as needed. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our current and future debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

Availability under our revolving credit facility is determined semi-annually, as well as upon the occurrence of certain events, by the lenders in their sole discretion, based primarily on reserve reports that reflect our banks' projections of future commodity prices at such time. Significant declines in natural gas, NGL or oil prices may result in a decrease in our borrowing base. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of all the lenders. If as a result of a borrowing base redetermination outstanding borrowings are in excess of the borrowing base, we must repay such excess borrowings immediately or in equal installments over six months, or we must pledge other properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

The inability of one or more of our operating partners to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($38.2 million in receivables at December 31, 2016), which operating partners market on our behalf to energy marketing companies, refineries and their affiliates.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with a limited number of operating partners. This concentration may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. The current low commodity price environment, which we believe may strain many of our operating partners, is likely to heighten this risk. The inability or failure of our operating partners to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease. A 1% increase in interest rates on the debt outstanding under our revolving credit facility as of December 31, 2016 would cost us approximately $1.4 million in additional annual interest expense.

Despite our current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our revolving credit facility, our senior notes and under any future debt agreements. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or deferred as a result of future legislation.

In February 2016, President Obama’s Administration released its proposed federal budget for fiscal year 2017 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;

- the elimination of current deductions for intangible drilling and development costs;

- the elimination of the deduction for U.S. oil and gas production activities;

- an extension of the amortization period for certain geological and geophysical expenditures; and

- the repeal of the enhanced oil recovery credit.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

Our articles of incorporation, bylaws, and Minnesota state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our articles of incorporation authorize our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our articles of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including, among others, limitations on the ability of our stockholders to call special meetings, limitations on the ability of our stockholders to act by written consent, and advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

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Minnesota law prohibits us from engaging in any business combination with any “interested stockholder,” meaning generally that a stockholder who owns 10% or more of our stock cannot acquire us for a period of four years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Pursuant to our January 2, 2015, agreement with TRT Holdings, Inc. (and certain of its affiliates), however, a 20% threshold applies for such parties instead of the statutory 10% threshold.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

Because we have no plans to pay, and are currently restricted from paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in the credit agreement governing our revolving credit facility and the indentures governing our senior notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

Estimated Net Proved Reserves

The table below summarizes our estimated net proved reserves at December 31, 2016, 2015 and 2014 based on reports prepared by Ryder Scott Company, LP ("Ryder Scott"), our independent reserve engineers. In preparing its reports, Ryder Scott evaluated properties representing all of our proved reserves at December 31, 2016, 2015 and 2014 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves in the table below do not include probable or possible reserves and do not in any way include or reflect our commodity derivatives.

	December 31, 2016		December 31, 2015		December 31, 2014	
	Proved Reserves (MBoe)(1)	% of Total	Proved Reserves (MBoe)(2)	% of Total	Proved Reserves (MBoe)(3)	% of Total
SEC Proved Reserves:						
Developed	37,713	70	42,177	65	51,046	51
Undeveloped	16,368	30	23,121	35	49,690	49
Total Proved Properties	54,081	100	65,298	100	100,736	100

(1) The table above values oil and natural gas reserve quantities as of December 31, 2016 assuming constant realized prices of $35.24 per barrel of oil and $1.67 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

(2) The table above values oil and natural gas reserve quantities as of December 31, 2015 assuming constant realized prices of $42.03 per barrel of oil and $1.63 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

(3) The table above values oil and natural gas reserve quantities as of December 31, 2014 assuming constant realized prices of $83.11 per barrel of oil and $7.37 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

Estimated net proved reserves at December 31, 2016 were 54,081 MBoe, a 17% decrease from estimated net proved reserves of 65,298 MBoe at December 31, 2015. The decrease in 2016 total proved reserves was primarily due to the impact of lower commodity prices in 2016 as compared to 2015, which also reduced both the number of undeveloped drilling locations and the expected productive life of economic locations reflected in our 2016 proved reserve estimates. Lower commodity prices and development activity in 2016 led to a reduction in our capital spending below discretionary cash flow levels. As a result of the lower activity levels, the number of proved undeveloped wells included in the reserves was reduced from 48.8 net wells in 2015 to 32.6 net wells in 2016 due to the 5-year rule requirements in the SEC regulations applicable to booking proved undeveloped reserves.

Estimated net proved reserves at December 31, 2015 were 65,298 MBoe, a 35% decrease from estimated net proved reserves of 100,736 MBoe at December 31, 2014. The decrease in 2015 total proved reserves was primarily due to the impact of lower commodity prices in 2015 as compared to 2014, which reduced both the number of locations from which reserves can be economically produced and the expected productive life of economic locations.

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The following table sets forth summary information by reserve category with respect to estimated proved reserves at December 31, 2016:

	SEC Pricing Proved Reserves[1]					
	Reserve Volumes				PV-10[3]	
Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)[2]	%	Amount (In thousands)	%
PDP Properties	30,514	30,974	35,676	66	$322,735	85
PDNP Properties	1,731	1,834	2,037	4	16,903	5
PUD Properties	14,030	14,024	16,368	30	39,784	10
Total	46,275	46,832	54,081	100	$379,422	100

(1) The SEC Pricing Proved Reserves table above values oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2016 based on average prices of $42.75 per barrel of oil and $2.49 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. The average resulting price used as of December 31, 2016, after adjustment to reflect applicable transportation and quality differentials, was $35.24 per barrel of oil and $1.67 per Mcf of natural gas.

(2) Boe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.

(3) Pre-tax PV10%, or "PV-10," 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 measure. See "Reconciliation of PV-10 to Standardized Measure" below.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, 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. The information in the table above does not give any effect to or reflect our commodity derivatives.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

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The following table reconciles the pre-tax PV10% value of our SEC Pricing Proved Reserves as of December 31, 2016 to the Standardized Measure of discounted future net cash flows.

SEC Pricing Proved Reserves	
(in thousands)	
Standardized Measure Reconciliation	
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$379,422
Future Income Taxes, Discounted at 10%[1]	(396)
Standardized Measure of Discounted Future Net Cash Flows	$379,026

(1) The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of our assets at December 31, 2016, our future income taxes were significantly reduced.

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer valuing the reserves. Further, our actual realized price for our oil and natural gas is not likely to average the pricing parameters used to calculate our proved reserves. As such, the oil and natural gas quantities and the value of those commodities ultimately recovered from our properties will vary from reserve estimates.

Additional discussion of our proved reserves is set forth under the heading “Supplemental Oil and Gas Information - Unaudited” to our financial statements included later in this report.

Proved Undeveloped Reserves

At December 31, 2016, we had approximately 16.4 MMBoe of proved undeveloped reserves as compared to 23.1 MMBoe at December 31, 2015. A reconciliation of the change in proved undeveloped reserves during 2016 is as follows:

	MMBoe
Estimated Proved Undeveloped Reserves at 12/31/2015	23.1
Converted to Proved Developed Through Drilling	(1.1)
Added from Extensions and Discoveries	7.1
Removed for 5-Year Rule	(3.4)
Removed Due to Low Commodity Prices	(8.7)
Revisions	(0.6)
Estimated Proved Undeveloped Reserves at 12/31/2016	16.4

During 2016, commodity prices for crude oil, NGL and natural gas experienced continued declines, which has resulted in lower capital spending during 2016 and is expected to approximate our discretionary cash flow in 2017. As a result, we have significantly reduced the proportion of our reserves that have historically been categorized as PUD. This is driven by the current economic price environment, coupled with the uncertain effect that such environment will have on the industry’s access to the capital markets, which reduces the number of PUD locations that we have reasonable certainty to believe will be developed during the five-year time horizon.

Our future development drilling program includes the drilling of approximately 32.6 proven undeveloped net wells before the end of 2021 at an estimated cost of $188.3 million. Our development plan for drilling proved undeveloped wells calls for the drilling of 13.8 net wells during 2017 (includes 7.3 net wells drilled at December 31, 2016, but classified as proved undeveloped due to Ryder Scott internal guidelines which require greater than 65% of total costs to be incurred to be classified as developed), 6.3 net wells during 2018, 4.2 net wells during 2019, 4.9 net wells during 2020 and 3.4 net wells during 2021 for a total of 32.6 net wells. We expect that our proved undeveloped reserves will continue to be converted to proved developed producing reserves as additional wells are drilled including our acreage. All locations comprising our remaining proved undeveloped reserves are forecast to be drilled within five years from initially being recorded in accordance with our development plan.

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At December 31, 2016, the PV-10 value of our proved undeveloped reserves amounted to 10% of the PV-10 value of our total proved reserves. Although our historical producing property additions exceed our existing development plans, there are numerous uncertainties. The development of these reserves is dependent upon a number of factors which include, but are not limited to: financial targets such as drilling within cash flow or reducing debt, drilling of obligatory wells, satisfactory rates of return on proposed drilling projects, and the levels of drilling activities by operators in areas where we hold leasehold interests. During 2016, Northern lowered its capital spending by 34% in response to the low commodity price environment. If the existing commodity price environment persists and prices remain lower-for-longer, we plan to continue development within available cash flows and potentially seek the acquisition of producing properties as sufficient liquidity allows. While lower commodity prices could reduce our future borrowing capacity (we had borrowing availability of $206 million under our revolving credit facility at December 31, 2016), with 85% of the PV-10 value of our total proved reserves supported by producing wells, we believe we will have sufficient cash flows and adequate liquidity to complete our development plan.

At December 31, 2016, we had spent a total of $10.8 million related to the development of proved undeveloped reserves, which resulted in the conversion of 1.1 MMBoe of proved undeveloped reserves as of December 31, 2015 to proved developed reserves as of December 31, 2016. Proved developed property additions in 2016 also included 0.8 MMBoe from the conversion of previously undeveloped locations that were not booked in our December 31, 2015 proved undeveloped reserves (the related development costs incurred at December 31, 2016 were $8.2 million). Additionally, our proved undeveloped reserves at December 31, 2016 included 2.2 MMBoe for net wells that had commenced drilling activities but remained classified as undeveloped reserves due to Ryder Scott's internal guidelines which require greater than 65% of the total costs to have been incurred in order to be classified as proved developed (the related development costs incurred at December 31, 2016 were $17.2 million). We added 7.1 MMBoe of proved undeveloped reserves primarily in our North Dakota areas of operations as a result of our 2016 drilling program and leasehold acquisitions. We added 294 gross (10.7 net) wells to production during 2016.

In 2016, we also had a net negative revision of 12.7 MMBoe, or 55% of our December 31, 2015 proved undeveloped reserves balance. The negative revision to proved undeveloped reserves in 2016 was driven by two primary factors: (i) significantly lower commodity pricing assumptions and (ii) changes in planned development due to the low commodity price environment that existed at year-end. The SEC-prescribed commodity prices (after adjustment for transportation, quality and basis differentials) were 16% lower per barrel of oil and 2% higher per Mcf of natural gas at year-end 2016 as compared to year-end 2015. The impact of the lower commodity prices in 2016 as compared to 2015 accounted for 69% of the negative revision, as approximately 8.7 MMBoe of proved undeveloped locations were removed from the 2016 reserve report because they became uneconomic due to lower realized pricing. The removal of undeveloped locations not expected to be developed in the existing commodity price environment at year-end resulted in 3.4 MMBoe of negative revisions and 0.6 MMBoe of negative revisions were a result of a change in previous estimates in 2016.

Proved Reserves Sensitivity by Price Scenario

The SEC disclosure rules allow for optional reserves sensitivity analysis, such as the sensitivity that oil and natural gas reserves have to price fluctuations. We have chosen to compare our proved reserves from the 2016 SEC case to two alternate pricing cases. These sensitivity scenarios were not audited by a third party. In these sensitivity scenarios, all factors other than the commodity price assumption have been held constant with the SEC case, including the number of proved undeveloped locations, drill schedules and operating costs assumptions. These sensitivities are only meant to demonstrate the impact that changing commodity prices may have on estimated proved reserves and PV-10 and there is no assurance these outcomes will be realized. The table below shows our proved reserves utilizing the 2016 SEC case compared with two alternate price scenarios.

Price Cases

	SEC Case[1]	Scenario 1[2]	Scenario 2[3]
Net Proved Reserves (December 31, 2016)			
Oil (MBbl)			
Developed	32,245	35,248	36,030
Undeveloped	14,030	14,326	14,404
Total	46,275	49,574	50,434
Natural Gas (MMcf)			
Developed	32,808	36,076	36,932
Undeveloped	14,024	14,302	14,376
Total	46,832	50,378	51,308
Total Proved Reserves (MBOE)	54,081	57,970	58,985

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(1) Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for transportation and quality differentials to arrive at prices of $35.24 per Bbl for oil and $1.67 per Mcf for natural gas. Production costs were held constant for the life of the wells.

(2) Prices based on $55.00 per Bbl for oil and $3.00 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $47.49 per Bbl for oil and $2.01 per Mcf for natural gas. Production costs and the future development drilling program were both held constant with the SEC case.

(3) Prices based on $60.00 per Bbl for oil and $3.25 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $52.49 per Bbl for oil and $2.18 per Mcf for natural gas. Production costs and the future development drilling program were both held constant with the SEC case.

The following table provides the estimated pre-tax PV10% value as of December 31, 2016, of our proved reserves under the SEC case and the two alternate price cases, and also reconciles these amounts to the standardized measure of discounted future net cash flows. Pre-tax PV10% value may be considered a non-GAAP financial measure. See "Reconciliation of PV-10 to Standardized Measure" above.

	SEC Case(1)	Scenario 1(2)	Scenario 2(3)
Standardized Measure Reconciliation (in thousands)			
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$379,422	$664,600	$783,004
Future Income Taxes, Discounted at 10%(4)	(396)	(2,525)	(13,980)
Standardized Measure of Discounted Future Net Cash Flows	$379,026	$662,075	$769,024

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(1) Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for transportation and quality differentials to arrive at prices of $35.24 per Bbl for oil and $1.67 per Mcf for natural gas. Production costs were held constant for the life of the wells.

(2) Prices based on $55.00 per Bbl for oil and $3.00 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $47.49 per Bbl for oil and $2.01 per Mcf for natural gas. Production costs and the future development drilling program were both held constant with the SEC case.

(3) Prices based on $60.00 per Bbl for oil and $3.25 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $52.49 per Bbl for oil and $2.18 per Mcf for natural gas. Production costs and the future development drilling program were both held constant with the SEC case.

(4) The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of our assets at December 31, 2016, our future income taxes were significantly reduced.

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Independent Petroleum Engineers

We have utilized Ryder Scott Company, LP ("Ryder Scott"), an independent reservoir engineering firm, as our third-party engineering firm. The selection of Ryder Scott is approved by our Audit Committee. Ryder Scott is one of the largest reservoir-evaluation consulting firms and evaluates oil and natural gas properties and independently certifies petroleum reserves quantities for various clients throughout the United States and internationally. Ryder Scott has substantial experience calculating the reserves of various other companies with operations targeting the Bakken and Three Forks formations and, as such, we believe Ryder Scott has sufficient experience to appropriately determine our reserves. Ryder Scott utilizes proprietary technology, systems and data to calculate our reserves commensurate with this experience. The reports of our estimated proved reserves in their entirety are based on the information we provide to them. Ryder Scott is a Texas Registered Engineering Firm (F-1580). Our primary contact at Ryder Scott is James L. Baird, Managing Senior Vice President. Mr. Baird is a State of Colorado Licensed Professional Engineer (License #41521).

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using average prices at the beginning of each month in the 12-month period prior to the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation).

The reserves set forth in the Ryder Scott report for the properties are estimated by performance methods or analogy. In general, reserves attributable to producing wells and/or reservoirs are estimated by performance methods such as decline curve analysis which utilizes extrapolations of historical production data. Reserves attributable to non-producing and undeveloped reserves included in our report are estimated by analogy. The estimates of the reserves, future production, and income attributable to properties are prepared using the economic software package Aries for Windows, a copyrighted program of Halliburton.

To estimate economically recoverable oil and natural gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future of production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined as of the effective date of the report. With respect to the property interests we own, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, production taxes, recompletion and development costs and product prices are based on the SEC regulations, geological maps, well logs, core analyses, and pressure measurements.

The reserve data set forth in the Ryder Scott report represents only estimates, and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the actual revenues and costs could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency. See "Item 1A. Risk Factors – Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves."

Internal Controls Over Reserves Estimation Process

We utilize Ryder Scott, a third-party reservoir engineering firm, as our independent reserves evaluator for 100% of our reserves base. In addition, we employ one internal reserve engineer who is responsible for overseeing the preparation of our reserves estimates. Our internal reserve engineer has a B.S. in petroleum engineering from Montana Tech and has over ten years of oil and gas experience on the reservoir side. Our engineer has experience working for large independent and financial firms on projects and acquisitions, both domestic and international.

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Our technical team meets with our independent third-party engineering firm to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;
- Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineer;
- Discussion of material reserve variances among our internal reservoir engineer and our executive management; and
- Review of a preliminary copy of the reserve report by executive management.

Production, Price and Production Expense History

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past few years, and the supply of oil could impact oil prices in the United States if the supply outstrips domestic demand. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices, like we have experienced since late 2014, or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Years Ended December 31,		
	2016	2015	2014
Net Production:			
Oil (Bbl)	4,325,91[illegible]	5,168,687	5,150,913
Natural Gas and NGLs (Mcf)	4,026,89[illegible]	4,651,583	3,682,781
Total (Boe)	4,997,06[illegible]	5,943,950	5,764,710
Average Sales Prices:			
Oil (per Bbl)	$35.22	$ 37.77	$ 79.23
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	14.22	31.17	(1.53)
Oil Net of Settled Derivatives (per Bbl)	49.44	68.94	77.70
Natural Gas and NGLs (per Mcf)	1.82	1.60	6.38

Realized Price on a Boe Basis Including all Realized Derivative Settlements	44.27	61.19	73.51
Average Costs:			
Production Expenses (per Boe)	$9.14	$ 8.77	$ 9.66

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Drilling and Development Activity

The following table sets forth the number of gross and net productive and non-productive wells drilled in the years ended December 31, 2016, 2015 and 2014. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated. We have classified all wells drilled to-date targeting the Bakken and Three Forks formations as development wells.

	Years Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Oil	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Development Wells:						
Oil	294	10.7	292	18.6	589	41.6
Natural Gas	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Total Productive Exploratory and Development Wells	294	10.7	292	18.6	589	41.6

The following table summarizes our cumulative gross and net productive oil wells by state at each of December 31, 2016, 2015 and 2014.

	At December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	2,820	202.2	2,533	192.6	2,243	174.1
Montana	94	10.9	97	11.7	95	11.6
Total	2,914	213.1	2,630	204.3	2,338	185.7

Leasehold Properties

As of December 31, 2016, our principal assets included approximately 155,016 net acres located in the northern region of the United States. The following table summarizes our estimated gross and net developed and undeveloped acreage by state at December 31, 2016.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota:						
Mountrail County	117,107	26,546	11,760	1,629	128,867	28,175
McKenzie County	99,952	24,250	15,726	6,196	115,678	30,446
Williams County	67,909	16,606	7,419	3,342	75,328	19,948
Dunn County	68,424	14,492	14,043	5,456	82,467	19,948
Divide County	55,936	15,073	5,866	2,973	61,802	18,046
Other	90,151	13,977	13,474	4,570	103,625	18,547
North Dakota	499,479	110,944	68,288	24,166	567,767	135,110
Montana	41,789	10,994	17,436	8,912	59,225	19,906
Total:	541,268	121,938	85,724	33,078	626,992	155,016

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As of December 31, 2016, approximately 79% of our total acreage was developed. All of our proved reserves are located in North Dakota and Montana.

Recent Acquisitions

In 2016 and 2015, we acquired leasehold interests covering an aggregate of approximately 3,399 and 4,355 net acres in our key prospect areas, for an average cost of $1,515 and $1,314 per net acre, respectively.

In 2016, the Company entered into a definitive purchase and sale agreement with a third party, for their interests in 144 gross (3.8 net) producing oil and gas wells and associated acreage.

We generally assess acreage subject to near-term drilling activities on a lease-by-lease basis because we believe each lease's contribution to a subject spacing unit is best assessed on that basis if development timing is sufficiently clear. Consistent with that approach, the majority of our acreage acquisitions involve properties that are "hand-picked" by us on a lease-by-lease basis for their contribution to a well expected to be spud in the near future, and the subject leases are then aggregated to complete one single closing with the transferor. As such, we generally view each acreage assignment from brokers, landmen and other parties as involving several separate acquisitions combined into one closing with the common transferor for convenience. However, in certain instances an acquisition may involve a larger number of leases presented by the transferors as a single package without negotiation on a lease-by-lease basis. In those instances, we still review each lease on a lease-by-lease basis to ensure that the package as a whole meets our acquisition criteria and drilling expectations.

Acreage Expirations

As a non-operator, we are subject to lease expirations if an operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other "savings clause" is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to establish production from most of our acreage prior to expiration of the applicable lease terms, there can be no guarantee we can do so. The approximate expiration of our net acres which are subject to expire between 2017 and 2021 and thereafter, are set forth below:

	Acreage Subject to Expiration	
Year Ended	Gross	Net
December 31, 2017	47,068	14,873
December 31, 2018	24,205	10,736
December 31, 2019	9,854	4,483
December 31, 2020	1,877	898
December 31, 2021 and thereafter	2,720	2,088
Total	85,724	33,078

During 2016, we had leases expire in Montana (9,265 net acres) and North Dakota (2,915 net acres) covering approximately 12,180 net acres, all of which was prospective for the Bakken and Three Forks Formations. The 2016 lease expirations carried a cost of $13.4 million. We believe that the expired acreage was not material to our capital deployed in these prospects.

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

We assess all items classified as unproved property on an annual basis, or if certain circumstances exist, more frequently, for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization. For the years ended

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December 31, 2016, 2015 and 2014, we included $7.0 million, $37.6 million and $21.4 million, respectively, related to expiring leases within costs subject to the depletion calculation.

We historically have acquired our properties by purchasing individual or small groups of leases directly from mineral owners or from landmen or lease brokers, which leases generally have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. We generally participate in drilling activities on a proportionate basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

We believe that the majority of our unproved costs will become subject to depletion within the next five years by proving up reserves relating to its acreage through exploration and development activities, by impairing the acreage that will expire before we can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of our reserves.

Impairment and Depletion of Oil and Natural Gas Properties

As a result of currently prevailing low commodity prices and their effect on the proved reserve values of properties in 2016 and 2015, we recorded a non-cash ceiling test impairment of $237.0 million and $1.2 billion in 2016 and 2015, respectively. There was no non-cash ceiling test impairment recorded in 2014. The impairment charge affected our reported net income but did not reduce our cash flow.

Depending on future commodity price levels, the trailing 12-month average price used in the ceiling calculation could decline and may cause additional future write downs of our oil and natural gas properties. Continued write downs of oil and natural gas properties are expected to occur until such time as commodity prices have stabilized or recovered long enough to stabilize or increase the trailing 12-month average price used in the ceiling calculation. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. At December 31, 2016, if the trailing 12-month average prices used in the impairment calculation had been 10% and 20% lower, our impairment expense would have increased by $78.4 million and $160.2 million, respectively.

Our depletion expense is driven by many factors including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. The following table presents our depletion expenses during 2016, 2015 and 2014.

	Years Ended December 31,		
	2016	2015	2014
Depletion of Oil and Natural Gas Properties	$60,637,746	$137,105,397	$172,106,389
Depletion Expense (per Boe)	12.13	23.07	29.86

Research and Development

We do not anticipate performing any significant research and development under our plan of operation.

Delivery Commitments

We do not currently have any delivery commitments for product obtained from our wells.

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Item 3. Legal Proceedings

Our company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

On August 16, 2016, Michael Reger filed a complaint against our company in the State of Minnesota, Fourth Judicial District, alleging breach of contract and defamation in connection with the company's termination of Mr. Reger's employment as chief executive officer on August 15, 2016. Mr. Reger's complaint alleges that the company breached his employment agreement by, among other things, purporting to terminate him for cause, removing him from the company's board of directors based on such termination, and denying him payments and other benefits to which he alleges that he is entitled under the employment agreement (including payments and benefits in connection with a termination without cause). Mr. Reger is seeking unspecified damages, an order reinstating him to the company's board of directors, and other equitable relief.

On August 18, 2016, plaintiff Jeffrey Fries, individually and on behalf of all others similarly situated, filed a putative class action complaint in the United States District Court for the Southern District of New York against our company, Michael Reger (our former chief executive officer), and Thomas Stoelk (our chief financial officer and interim chief executive officer) as defendants. The complaint purports to bring a federal securities class action on behalf of a class of persons who acquired the company's securities between March 1, 2013 and August 15, 2016, and seeks to recover damages caused by defendants' alleged violations of the federal securities laws and to pursue remedies under Sections 10(a) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder.

Item 4. Mine Safety Disclosures

None.

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PART II

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

Market Information

Our common stock trades on the NYSE MKT under the symbol "NOG." The high and low sales prices for shares of common stock of our company for each quarter during 2015 and 2016 are set forth below.

	Sales Price	
	High	Low
Fiscal Year Ended December 31, 2015		
First Quarter	$9.48	$5.16
Second Quarter	9.51	6.15
Third Quarter	6.74	4.05
Fourth Quarter	5.95	3.36
Fiscal Year Ended December 31, 2016		
First Quarter	5.07	1.99
Second Quarter	5.85	3.70
Third Quarter	4.94	2.52
Fourth Quarter	3.50	1.55

The closing price for our common stock on the NYSE MKT on February 28, 2017 was $3.00 per share.

Comparison Chart

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

The following graph compares the 60-month cumulative total shareholder return on our common stock since December 31, 2011, and the cumulative total returns of Standard & Poor’s Composite 500 Index and the NYSE Arca Oil Index (formerly the AMEX Oil Index) for the same period. This graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends) from December 31, 2011 to December 31, 2016.

*$100 invested on 12/31/11 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

* The following table sets forth the total returns utilized to generate the foregoing graph.

	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016
Northern Oil & Gas, Inc.	100.00	70.14	62.84	23.56	16.10	11.47
S&P 500	100.00	116.00	153.58	174.60	177.01	198.18
NYSE Arca Oil Index	100.00	101.96	120.73	110.50	92.08	115.46

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Holders

As of February 28, 2017, we had 63,251,197 shares of our common stock outstanding, held by approximately 266 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

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Dividends

The payment of dividends is subject to the discretion of our Board of Directors and will depend, among other things, upon our earnings, our capital requirements, our financial condition, and other relevant factors. We have not paid or declared any dividends upon our common stock since our inception and do not presently anticipate paying any dividends upon our common stock in the foreseeable future. Under our revolving credit facility, we are restricted in our ability to pay cash dividends on our common stock. Any cash dividends in the future to common shareholders will be payable when, as and if declared by our Board of Directors based upon the Board's assessment of:

- our financial condition and performance;
- earnings;
- need for funds;
- capital requirements;
- prior claims of preferred stock to the extent issued and outstanding; and
- other factors, including income tax consequences, contractual restrictions and any applicable laws.

There can be no assurance, therefore, that any dividends on the common stock will ever be paid.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of our common stock during the quarter ended December 31, 2016.

Period	Total Number of Shares Purchased[1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publically Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs[2]
Month #1 October 1, 2016 to October 31, 2016	—	$ —	—	$ 108.3 million
Month #2 November 1, 2016 to November 30, 2016	969	2.00	—	108.3 million
Month #3				

December 1, 2016 to December 31, 2016	32,258	2.29	—	108.3 million
Total	33,227	$ 2.29	—	$ 108.3 million

(1) All shares purchased reflect shares surrendered in satisfaction of tax obligations in connection with the vesting of restricted stock awards.

(2) In May 2011, our board of directors approved a stock repurchase program to acquire up to $150 million worth of shares of our Company's outstanding common stock. In total, we have repurchased 3,190,268 shares under this program through December 31, 2016 at a weighted average price of $13.06 per share. The last time we repurchased shares under this program was in 2014.

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Item 6. Selected Financial Data

	Fiscal Years				
	2016	2015	2014	2013	2012
	(in thousands, except share and per common share data)				
Statements of Operations Information:					
Revenues					
Oil and Gas Sales	$159,691	$202,639	$431,605	$369,187	$296,638
Gain (Loss) on Derivative Instruments, Net	(14,819)	72,383	163,413	(33,458)	14,756
Other Revenue	31	36	9	44	179
Total Revenues	144,903	275,057	595,027	335,773	311,573
Operating Expenses					
Production Expenses	45,680	52,108	55,696	41,859	32,382
Production Taxes	15,514	21,567	43,674	34,959	28,486
General and Administrative Expense	14,758	19,042	17,602	16,575	22,645
Depletion, Depreciation, Amortization and Accretion	61,244	137,770	172,884	124,383	98,923
Impairment of Oil and Natural Gas Properties	237,013	1,163,959	—	—	—
Total Expenses	374,208	1,394,446	289,855	217,776	182,436
Income (Loss) from Operations	(229,305)	(1,119,388)	305,171	117,997	129,137
Interest Expense, Net of Capitalization	(64,486)	(58,360)	(42,106)	(32,709)	(13,875)
Write-off of Debt Issuance Costs	(1,090)	—	—	—	—
Other Income (Expense)	(16)	(30)	47	(453)	25
Total Other Income (Expense)	(65,591)	(58,390)	(42,058)	(33,162)	(13,850)
Income (Loss) Before Income Taxes	(294,896)	(1,177,779)	263,113	84,835	115,287
Income Tax Provision (Benefit)	(1,402)	(202,424)	99,367	31,768	43,002
Net Income (Loss)	$(293,494)	$(975,355)	$163,746	$53,067	$72,285
Net Income (Loss) Per Common Share – Basic	$(4.80)	$(16.08)	$2.70	$0.85	$1.16
Net Income (Loss) Per Common Share – Diluted	$(4.80)	$(16.08)	$2.69	$0.85	$1.15
Weighted Average Shares Outstanding – Basic	61,173,547	60,652,447	60,691,701	62,364,957	62,485,836
Weighted Average Shares Outstanding – Diluted	61,173,547	60,652,447	60,860,769	62,747,298	62,869,079
Statements of Cash Flows Information:					
Net Cash Provided By Operating Activities	$101,892	$247,016	$274,258	$222,774	$198,527
Net Cash Used For Investing Activities	$(90,964)	$(288,936)	$(477,040)	$(358,536)	$(532,172)
Net Cash (Used For) Provided By Financing Activities	$(7,832)	$35,973	$206,433	$128,061	$340,754

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	Fiscal Years				
	2016	2015	2014	2013	2012
	(in thousands)				
Balance Sheet Information:					
Assets:					
Cash and Cash Equivalents	$6,486	$3,390	$ 9,338	$ 5,687	$ 13,388
Total Current Assets	46,894	122,030	226,000	104,388	94,215
Total Property and Equipment, Net	376,208	589,320	1,761,927	1,397,307	1,083,245
Total Assets	431,533	721,431	2,026,746	1,519,600	1,190,935
Liabilities:					
Total Current Liabilities	77,444	78,115	285,734	194,088	100,457
Revolving Line of Credit	144,000	150,000	298,000	75,000	124,000
8% Senior Notes	688,625	685,290	508,053	509,540	300,000
Total Liabilities	918,955	919,033	1,255,885	899,772	604,750
Total Stockholders' Equity (Deficit)	(487,422)	(197,602)	770,861	619,828	586,185

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

The following discussion should be read in conjunction with the "Selected Financial Data" in Item 6 and the Financial Statements and Accompanying Notes appearing elsewhere in this report.

Overview of 2016 Results

During 2016, we achieved the following financial and operating results:

- 2016 new well additions averaged an estimated 27% rate of return based upon NYMEX strip prices at year-end;
- Decreased total capital expenditures below discretionary cash flows allowing for a year-over-year reduction in bank borrowings;
- Reduced cash general and administrative expenses by $1.2 million or 9% compared to 2015;
- Added 294 gross (10.7 net) wells to production;
- Amended covenant requirements in bank agreements to relax the covenant requirements up to June 30, 2018; and
- Ended 2016 in a strong liquidity position with borrowing availability under our revolving credit facility of $206 million.

Operationally, 2016 proved to be another challenging year due to low commodity prices. North Dakota drilling activity declined approximately 45% during the year with the majority of activity focused in the core areas located in McKenzie, Mountrail, Williams and Dunn counties. Since approximately 98,517 net acres or 64% of Northern's total lease inventory is located in those four counties, we were able to add 10.7 net wells to production in 2016 and increase our in-process inventory to 13.4 net uncompleted wells at year-end. In response to low commodity prices in 2016, we lowered our capital expenditures by 34% to $84.5 million as compared to last year, which was less than discretionary cash flow generated by operations. Through continued capital discipline, the development wells that we elected to participate in during 2016 have an estimated ultimate recovery ("EUR") average of 787 MBoe.

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Low commodity prices and reduced development activity in the Williston Basin led to a reduction in our capital expenditures and new well additions in 2016, which contributed to the 16% reduction in average daily production for 2016 when compared to 2015. On a Boe basis, approximately 87% of our production is derived from crude oil, which significantly affected our revenues due to the low oil price environment. During 2016, our average sales price per barrel, after reflecting the impact of settled derivatives, decreased by 28% as compared to 2015. The lower average sales price in 2016 as compared to 2015 was due to a decline in the average NYMEX prices per barrel, a lower overall percentage of oil hedged, as well as lower fixed prices received on the settled derivative transactions during 2016. Approximately 42% of Northern's 2016 oil production was hedged using derivative arrangements that increased our realized oil price per Bbl by $14.22. Our oil, natural gas and NGL sales, including the effect of settled derivatives, totaled $221.2 million in 2016, which is a 39% decrease as compared to 2015. Total revenues decreased 47% or $130.2 million in 2016 compared to 2015.

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements. Our average realized price calculations include the effects of the settlement of all derivative contracts regardless of the accounting treatment.

Principal Components of Our Cost Structure

- Oil price differentials. The price differential between our Williston Basin well head price and the NYMEX WTI benchmark price is driven by the additional cost to transport oil from the Williston Basin via train, barge, pipeline or truck to refineries.

- Gain (loss) on derivative instruments, net. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash market-to-market gains and losses we incur on derivative instruments outstanding at period end.

- Production expenses. Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

- Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

- Depreciation, depletion, amortization and impairment. Depreciation, depletion, amortization and impairment includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method.

- General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

- Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our full cost pool. We include interest expense that is not capitalized into the full cost pool, the amortization of deferred financing costs and bond premiums (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

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- Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;
- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of our acreage and wells in the Williston Basin subjects our operating results to factors specific to this region. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, and the limitations of the developing infrastructure and transportation capacity in this region.

The price of oil in the Williston Basin can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market. Light sweet crude from the Williston Basin has a higher value at many major refining centers because of its higher quality relative to heavier and sour grades of oil; however, because of North Dakota’s location relative to traditional oil transport centers, this higher value is generally offset to some extent by higher transportation costs. While rail transportation has historically been more expensive than pipeline transportation, Williston Basin prices have justified shipment by rail to markets such as St. James, Louisiana, which offers prices benchmarked to Brent/LLS. Although pipeline, truck and rail capacity in the Williston Basin has historically lagged production in growth, we believe that additional planned infrastructure growth will help keep price discounts from significantly eroding wellhead values in the region.

The price at which our oil production is sold typically reflects a discount to the NYMEX WTI benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX WTI and the sales prices we receive for our oil production. Our oil price differential to the NYMEX WTI benchmark price during 2016 was $8.25 per barrel, as compared to $9.42 per barrel in 2015. Fluctuations in our oil price differential are due to several factors such as takeaway capacity relative to production levels in the Williston Basin, and seasonal refinery maintenance temporarily depressing crude demand. As the rail capacity continues to increase and planned pipeline expansions are completed, we believe the oil price differentials will improve.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells has varied significantly over the past few years as volatility in oil prices has substantially impacted the level of drilling activity in the Williston Basin. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the choice of proppant (sand or ceramic).

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Given the significant decline in oil and gas prices that began in the second half of 2014, drilling activity in the Williston Basin has significantly reduced. North Dakota's average rig count dropped from an average of 58 in December 2015 to 32 in December 2016. The declines in drilling activity and commodity prices have recently lowered drilling costs. During 2016, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $7.0 million, compared to $7.7 million for the wells we elected to participate in during 2015.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Being primarily an oil producer, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially the production quota set by OPEC, and the strength of the U.S. dollar has adversely impacted oil prices. Additionally, an economic slowdown in Europe and Asia has reduced overall demand. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2016, 2015 and 2014.

	Years Ended December 31,		
	2016	2015	2014
Average NYMEX Prices(1)			
Oil (per Bbl)	$43.47	$48.76	$92.91
Natural Gas (per MMBtu)	2.55	2.63	4.26

(1) Based on average NYMEX closing prices.

Oil and natural gas prices have fallen significantly since their early third quarter 2014 levels. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices has adversely affected our business and may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce. During 2016, the average WTI NYMEX pricing was $43.47 per barrel or 11% lower than the average NYMEX price per barrel in 2015. Although oil and natural gas prices have shown slight increases, if a lower pricing environment reoccurs our net revenue per BOE could decrease due to the lower average WTI NYMEX prices, as well as a reduced percentage of our oil production being hedged in 2017 as compared to 2016. Also, lower oil and gas prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves. At December 31, 2016, we have hedged 3.3 million barrels in 2017 and 2018 with swaps at an average price of $53.00 per barrel. Additionally, as of December 31, 2016, we had hedged 0.3 million barrels under costless collar arrangements in 2017 with an average floor price of $50.00 per barrel and an average ceiling price of $60.06 per barrel.

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Results of Operations for 2016, 2015 and 2014

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Years Ended December 31,		
	2016	2015	2014
Net Production:			
Oil (Bbl)	4,325,919	5,168,687	5,150,913
Natural Gas and NGLs (Mcf)	4,026,899	4,651,583	3,682,781
Total (Boe)	4,997,069	5,943,950	5,764,710
Net Sales (in thousands):			
Oil Sales	$152,348	$195,203	$408,124
Natural Gas and NGL Sales	7,343	7,436	23,481
Gain (Loss) on Derivative Instruments, Net	(14,819)	72,383	163,413
Other Revenue	31	36	9
Total Revenues	144,903	275,058	595,027
Average Sales Prices:			
Oil (per Bbl)	$35.22	$37.77	$79.23
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	14.22	31.17	(1.53)
Oil Net of Settled Derivatives (per Bbl)	49.44	68.94	77.70
Natural Gas and NGLs (per Mcf)	1.82	1.60	6.38
Realized Price on a Boe Basis Including all Realized Derivative Settlements	44.27	61.19	73.51
Operating Expenses (in thousands):			
Production Expenses	$45,680	$52,108	$55,696
Production Taxes	15,514	21,567	43,674
General and Administrative Expense	14,758	19,042	17,602
Depletion, Depreciation, Amortization and Accretion	61,244	137,770	172,884
Costs and Expenses (per Boe):			
Production Expenses	$9.14	$8.77	$9.66
Production Taxes	3.10	3.63	7.58
General and Administrative Expense	2.95	3.20	3.05
Depletion, Depreciation, Amortization and Accretion	12.26	23.18	29.99
Net Producing Wells at Period End	213.1	204.3	185.7

Oil and Natural Gas Sales

Our revenues vary from year to year primarily as a result of changes in realized commodity prices and production volumes. In 2016, oil, natural gas and NGL sales, excluding the effect of settled derivatives, decreased 21% from 2015, driven primarily by a 16% decrease in production and a 7% decrease in our average oil sales price. The lower average realized price per Boe, excluding the effect of settled derivatives, in 2016 as compared to 2015 was primarily driven by lower average NYMEX oil and gas prices, which were partially offset by a lower oil price differential. Oil price differential during 2016 averaged $8.25 per barrel, as compared to $9.42 per barrel in 2015.

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In 2015, oil, natural gas and NGL sales decreased 53% from 2014, driven primarily by a 52% decrease in our average oil sales price, excluding the effect of settled derivatives, but partially offset by a 3% increase in production. The lower average realized price per Boe, excluding the effect of settled derivatives, in 2015 as compared to 2014 was primarily driven by lower average NYMEX oil and gas prices, which were partially offset by a lower oil price differential. Oil price differential during 2015 average $9.42 per barrel, as compared to $13.67 per barrel in 2014.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas sales from existing wells. Low commodity prices and reduced development activity in the Williston Basin caused our 2015 annual capital expenditure spending to be reduced by 76% as compared to the prior year and lowered the number of new wells placed into production. In 2016, low commodity prices and reduced activity persisted and our annual capital expenditure spending was further reduced by 34% compared to 2015. Although the per well productivity of our wells has improved, that was more than offset by the natural decline of oil and gas production in 2016 due to the lower number of new wells placed into production. In addition, during 2016 certain of our operators have curtailed production due to their desire to produce the wells at higher prices than currently exist, and/or shut-in production to protect surrounding wells while completion activities were occurring on new wells being drilled. Fewer new well additions coupled with these production curtailments and shut-in wells resulted in a production volume decrease of 16% in 2016 compared to 2015. The higher number of net well completions in 2015, coupled with a higher number of well completions during 2014 resulted in a 3% increase in production volumes in 2015, as compared to 2014. The net productive wells added to production in 2016, 2015 and 2014 was 10.7, 18.6 and 41.6, respectively. Our production for each of the last three years is set forth in the following table:

	Years Ended December 31,		
	2016	2015	2014
Production			
Oil (Bbl)	4,325,919	5,168,687	5,150,913
Natural Gas and NGL (Mcf)	4,026,899	4,651,583	3,682,781
Total (Boe)(1)	4,997,069	5,943,950	5,764,710
Average Daily Production			
Oil (Bbl)	11,819	14,161	14,112
Natural Gas and NGL (Mcf)	11,002	12,744	10,090
Total (Boe)(1)	13,653	16,285	15,794

(1) Natural gas and NGLs are converted to Boe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on derivative instruments, net was a loss of $14.8 million in 2016, compared to a gain of $72.4 million in 2015, and a gain of $163.4 million in 2014. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on derivative instruments outstanding at period-end.

For 2016, we realized a gain on settled derivatives of $61.5 million, compared to a $161.1 million gain in 2015 and a $7.9 million loss in 2014. The percentage of oil production hedged under our derivative contracts was 42%, 77%, and 46% in 2016, 2015, and 2014, respectively. The weighted average oil price on our settled derivative contracts in 2016, 2015, and 2014 was $77.50, $89.44, and $91.49, respectively. Our average realized price (including all cash derivative settlements) in 2016 was $44.27 per Boe compared to $61.19 per Boe in 2015, and $73.51 per Boe in 2014. The gain (loss) on settled derivatives increased our average realized price per Boe by $12.31 in 2016, increased our average realized price per Boe by $27.10 in 2015 and decreased our average realized price per Boe by $1.36 in 2014.

Mark-to-market derivative gains and losses was a loss of $76.3 million in 2016 compared to a loss of $88.7 million in 2015 and a gain of $171.3 million in 2014. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Any gains on our derivatives will be offset by lower wellhead revenues in the future or any losses will be offset by higher future wellhead revenues based on the value at the settlement date. At December 31, 2016, all of our derivative contracts are recorded at their fair value, which was a net liability of $11.7 million, a decrease of $76.3 million from the $64.6 million net asset recorded as of December 31, 2015. The increase in the net liability at December 31, 2016 as compared to net asset at December 31, 2015 was primarily due to settlements of those derivative instruments that matured during 2016, as well as changes in oil prices on the open oil derivative contracts. Our open oil derivative contracts are summarized in "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Production Expenses

Production expenses were $45.7 million in 2016 compared to $52.1 million in 2015 and $55.7 million in 2014. On a per unit basis, production expenses increased 4% from $8.77 per Boe in 2015 to $9.14 per Boe in 2016 due to lower production levels over which fixed costs are spread. On an absolute dollar basis, our production expenses in 2016 were 12% lower when compared to 2015 due primarily to lower contract labor and maintenance costs and reduced variable costs on lower production levels which was partially offset by a 4% increase in the total number of net wells. On a per unit basis, production expenses decreased 9% from $9.66 per Boe in 2014 to $8.77 per Boe in 2015. On an absolute dollar basis, our production expenses in 2015 were 6% lower when compared to 2014 due primarily to lower contract labor and maintenance costs which was partially offset by a 3% increase in production levels and a 10% increase in the total number of net wells.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Lower production tax rates, production levels and commodity prices in 2016 as compared to 2015 lowered the taxable base that is used to calculate production taxes. Lower commodity prices in 2015 as compared to 2014 lowered the taxable base that is used to calculate production taxes. Production taxes were $15.5 million in 2016 compared to $21.6 million in 2015 and $43.7 million in 2014. As a percentage of oil and natural gas sales, our average production tax rates were 9.7%, 10.6% and 10.1% in 2016, 2015 and 2014, respectively. In 2016, the decrease in production tax rates as a percentage of oil and gas sales is due to a lower oil production tax rate in North Dakota, which dropped to 10% beginning in 2016. The 2015 average production tax rates were higher than the 2014 average due to fewer wells that qualified for reduced rates or tax exemptions.

General and Administrative Expense

General and administrative expense was $14.8 million for 2016 compared to $19.0 million for 2015 and $17.6 million for 2014. General and administrative expenses in 2016 as compared to 2015 were lower due primarily to a $5.9 million decrease in compensation expenses due in large part to the termination of the employment of the Company's chief executive officer, which resulted in the reversal of $3.2 million in compensation expenses. Additionally, compensation expenses in 2016 were lower as compared to 2015 due to workforce reductions in the fourth quarter of 2015 and $1.9 million of stock-based compensation costs incurred in 2015 in connection with a new employment agreement with our former chief executive officer. Partially offsetting the lower compensation expenses in 2016 was a

$1.4 million increase in legal expenses and $0.5 million in other professional fees.

General and administrative expenses in 2015 as compared to 2014 included higher compensation expenses of $3.9 million that included $0.5 million of restructuring expenses incurred in connection with workforce reductions in response to the low commodity price environment. The 2015 increase in compensation expenses is comprised of $0.7 million of cash expense and $3.2 million of non-cash stock based compensation expense. The higher stock based compensation costs during 2015 included $1.9 million of expense recognized in connection with a new employment agreement with our former chief executive officer. Partially offsetting the higher compensation expenses in 2015 were cost reductions in legal and professional expenses ($1.4 million), travel expenses ($0.6 million) and insurance expenses ($0.5 million).

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Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $61.2 million in 2016 compared to $137.8 million in 2015 and $172.9 million in 2014. Depletion expense, the largest component of DD&A, was $12.13 per Boe in 2016 compared to $23.07 per Boe in 2015 and $29.86 per Boe in 2014. The aggregate decrease in depletion expense for 2016 compared to 2015 was driven by a 47% decrease in the depletion rate per Boe, as well as a 16% decrease in production levels. The 2016 depletion rate per Boe was lower due to the impairment of oil and gas properties, which lowered the depletable base. The aggregate decrease in depletion expense for 2015 compared to 2014 was driven by a 23% decrease in the depletion rate per Boe, which was partially offset by a 3% production increase in 2015 as compared to 2014. The 2015 depletion rate per Boe was lower due to the impairment of oil and gas properties, which lowered the depletable base. The following table summarizes DD&A expense per Boe for 2016, 2015 and 2014:

	Years Ended December 31,				Years Ended December 31,			
	2016	2015	Change	Change	2015	2014	Change	Change
Depletion	$12.13	$23.07	$(10.94)	(47)%	$23.07	$29.86	$(6.79)	(23)%
Depreciation, Amortization, and Accretion	0.13	0.11	0.02	18 %	0.11	0.13	(0.02)	(15)%
Total DD&A expense	$12.26	$23.18	$(10.92)	(47)%				