

NORTHERN OIL & GAS, INC.
Form 10-K
March 03, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

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

(State or Other Jurisdiction of Incorporation or
Organization)

95-3848122

(I.R.S. Employer Identification No.)

315 Manitoba Avenue – Suite 200, Wayzata, Minnesota 55391

(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
Common Stock, \$0.001 par value

Name of Each Exchange On Which Registered
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

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

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

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

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

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

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 \$802.2 million.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of February 21, 2014, the registrant had 61,852,670 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2014 Annual Meeting of Shareholders are incorporated by reference into Part III of this annual report.

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," "anticipate," "target," "plan," "intend," "seek," "goal," "will," "should," "may" 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: crude oil and natural gas prices, our ability to raise or access capital, 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, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, 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 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.

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“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 accumulations 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 (PDP’s).” 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 (PDNP’s).” 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 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.

(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 12-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.” The estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, calculated in accordance with Accounting Standards Codification (“ASC”) 932, formerly Statement of Financial Accounting Standards No. 69 “Disclosures About Oil and Gas Producing Activities.”

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, 2013

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 2013, we participated in the drilling and completion of 531 gross (40.0 net) wells in the Williston Basin. At December 31, 2013, we owned working interests in 1,758 gross (146.2 net) producing wells, consisting of 1,754 wells targeting the Bakken and Three Forks formations and four exploratory wells targeting other formations. As of December 31, 2013, we leased approximately 187,044 net acres, all located in the Williston Basin, of which approximately 107,999 net acres were developed.

As of December 31, 2013, our proved reserves were 84.2 MMBoe (all of which were in the Williston Basin) as estimated by our third-party independent reservoir engineering firm, Ryder Scott Company, LP, which represents 25% growth in our proved reserves compared to year end 2012. As of December 31, 2013, 42% of our reserves were classified as proved developed and 90% of our reserves were oil. The following table provides a summary of certain information regarding our assets:

	As of December 31, 2013							
	Net Acres	Productive Wells		Average Daily Production(1) (Boe per day)	Proved Reserves (MMBoe)	% Oil	% Proved	
Gross		Net	Developed					
North Dakota	145,335	1,672	134.7	13,440	82,774	90 %	42 %	\$1,493,032
Montana	41,709	86	11.5	506	1,386	88 %	67 %	28,257
Total	187,044	1,758	146.2	13,946	84,160	90 %	42 %	\$1,521,289

- (1) Represents the average daily production over the three months ended December 31, 2013.
- (2) PV-10 is a non-GAAP financial measure. For further information and reconciliation to the most directly comparable GAAP measure, see “Item 2. Properties–Proved Reserves.” The prices used to calculate this measure were \$96.78 per barrel of oil (WTI price) and \$3.67 per MMBtu of natural gas (Henry Hub price), which prices were then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2013 was \$88.00 per barrel of oil and \$5.23 per Mcf of natural gas.

Historically, we have acquired properties by purchasing individual or small groups of leases directly from mineral owners or from landmen or lease brokers, as well as by purchasing lease packages in identified project areas controlled by specific operators. We have increasingly focused our efforts on acquiring properties subject to specific drilling projects or included in permitted or drilling spacing units. We believe that our history of acquiring oil and gas interests in the Williston Basin, our early participation in the unconventional development of the Bakken and Three Forks formations and the relationships we have established with the various operators within the basin, provide us a competitive advantage in our efforts to secure additional oil and gas properties within the Williston Basin.

We seek to create value through strategic acreage acquisitions and partnering with operators who have experience in developing and producing oil in our core areas. We have targeted specific prospects and have consistently participated in drilling programs in the Williston Basin. We have more than 25 experienced operating partners that provide both technical capabilities and additional sources for acreage acquisitions. Additionally, through our participation in 1,758 gross (146.2 net) producing wells, we have assembled an extensive database of information related to well performance for different areas of the Williston Basin, which helps us evaluate acquisition opportunities and the drilling programs of our operating partners.

Business Strategy

Our business strategy is to create value for our shareholders by growing reserves, production and cash flow on a cost-efficient basis. Key elements of our business strategies include:

- **Continue Participation in the Development of Our Existing Properties in the Williston Basin as a Non-Operator.** Development of our existing position in the Williston Basin resource play is our primary objective. We plan to continue to concentrate our capital expenditures in the Williston Basin, where we believe our current acreage position provides 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 Larger 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, 2013, we have participated in 1,758 gross (146.2 net) producing wells in the Williston Basin with an average working interest of 8.3% in each gross well, with more than 25 experienced operating partners. We expect to continue partnering with numerous experienced operators across our leasehold positions.
- **Make Strategic Acquisitions in the Williston Basin at Attractive Prices.** 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. Historically, we have acquired properties by purchasing individual or small groups of leases directly from mineral owners or from landmen or lease brokers, as well as purchasing lease packages in identified project areas controlled by specific operators. We believe this acquisition strategy will allow us to expand our operations at attractive prices. During 2013, we acquired 20,900 net acres at an average cost of \$1,279 per acre. In addition, during 2013 we separately acquired working interests in 70 gross (7.0 net) wells in undrilled locations in which we do not hold the underlying leasehold interests, for a total cost of approximately \$9.0 million. During 2012, we acquired approximately 17,590 net acres at an average cost of \$1,788 per acre, and earned an additional 6,450 net acres through farm-in arrangements.
- **Maintain a Strong Balance Sheet and Actively Manage Commodity Price Risk.** Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity

price volatility. We employ an active commodity price risk management program to better enable us to execute our business plan over the entire commodity price cycle. Our current program includes a combination of swaps and costless collars on a significant percentage of our expected production over a rolling 24 to 36-month horizon. The following table summarizes the oil derivative contracts that we have entered into for each year as of December 31, 2013:

Costless Collars

Contract Period	Volume (Bbl)	Average Floor	Average Ceiling
2014	240,000	\$90.00	\$99.05

Swaps

Contract Period	Volume (Bbl)	Average Price
2014	3,750,000	\$90.46
2015	2,880,000	\$89.02

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. Daily WTI oil prices averaged \$98.05 per barrel in 2013 with a high of \$110.53 per barrel in September and a low of \$86.68 per barrel in April. 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 and continued lower product demand caused by a weakened economy. Natural gas prices are generally determined by North American supply and demand and are also affected by imports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

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, expertise of the operator and completed well cost from each project, as well as other factors. At the present time we expect to participate pursuant to our working interest in a majority of the wells proposed to us.

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 2013 was \$8.68 per barrel below NYMEX pricing. Our weighted average differential was approximately

\$14.98 per barrel below NYMEX pricing during the fourth quarter of 2013. 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.

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 natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and 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 properties are subject to customary royalty 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 all of 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.

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. All lease arrangements that comprise our acreage positions are 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.

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.

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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 establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. 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. Although we believe we are currently in substantial compliance with all applicable laws and regulations, 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.

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.

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 will be 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 EPA finalized rules proposed on July 28, 2011 that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance Standards 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. 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 subject hydraulic fracturing operations to regulation under the Act’s Underground Injection Control Program to require disclosure of chemicals used in the hydraulic fracturing process.

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. 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, or 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 global warming, 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," and 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, although on October 15, 2013, the U.S. Supreme Court announced it will review aspects of the rule in 2014. In 2013, one state, Colorado, proposed the imposition of controls on methane emissions from oil and gas facilities and there have been formal requests filed with the federal government that the EPA restrict emissions of methane from 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.

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 greenhouse gas 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 20 full time employees. As drilling production activities continue to increase, we may hire additional technical or administrative personnel as appropriate. 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 315 Manitoba Avenue, Suite 200, Wayzata, Minnesota 55391. Our office space consists of 4,653 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 current 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 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

Risks Related to our Business

Oil and natural gas prices are volatile. A protracted period of depressed oil and natural gas prices could adversely affect our 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. The prices we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. 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;
 - 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 may not only decrease our revenues but also may reduce the amount of oil and natural gas that our operators can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in 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. 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. Lower oil and natural gas prices may also 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.

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 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 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, 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.

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:

- 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;
 - unusual or unexpected geological formations;
 - loss of drilling fluid circulation;
 - 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.

If oil or natural gas prices decrease or drilling efforts are unsuccessful, we may be required to record writedowns of our oil and natural gas properties.

We could be required to write down the carrying value of certain of our oil and natural gas properties. 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.

Accounting rules require that the carrying value of oil and natural gas properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proved property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and natural gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. While an impairment charge reflects our long-term ability to recover an investment, reduces our reported earnings and increases our leverage ratios, it does not impact cash or cash flow from operating activities.

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.

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 successful business operations depends on the success of our 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.

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:

- 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.

Recently, major international oil and gas companies have publicly announced significant acquisition and joint venture transactions within the Williston Basin. This has resulted in increased activity and investment in the region. As 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.

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 industry 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.

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.

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 the shut-in of producing wells or the delay or discontinuance of development plans for our properties. The curtailments arising from these and similar circumstances may last from a few days to several months. 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, 2013, we estimate that we had leases that were not developed that represented 24,085 net acres potentially expiring in 2014, 21,998 net acres potentially expiring in 2015, 14,656 net acres potentially expiring in 2016 and 11,678 net acres potentially expiring in 2017 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 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. The decline in oil and natural gas prices in 2008 adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices (particularly oil prices) decline, it will have similar 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, which could restrict our ability to grow.

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.

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;
- 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, specifically those of Mr. Reger our Chief Executive Officer, 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.

Although all of the members of our management team have entered into employment agreements with us, they 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. 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 in obtaining rights to explore and develop oil and natural gas reserves and to market our production may impair our business.

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.

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.

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. Such spin-offs may occur at any time until mid-2015 depending on regulators’ decisions to allow a transitional period for a given counterparty. 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 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.

Environmental risks may adversely affect our business.

All phases of the oil and natural gas business 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 by 2014 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the DOI published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The revised proposed rule was subject to an extended 90-day public comment period, which ended on August 23, 2013.

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 and a final draft is anticipated by 2014 for peer review and public comment. 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, depending on their results, 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, EPA promulgated New Source Performance Standards 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, 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.

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.

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.

In December 2009, the U.S. Environmental Protection Agency (the “EPA”) determined that emissions of carbon dioxide, methane and other “greenhouse gases” (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to 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, although on October 15, 2013, the U.S. Supreme Court announced it will review aspects of the rule in 2014. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the September 2013 proposed GHG rule that, if finalized, would set new source performance standards for new coal-fired and natural gas-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

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
 - engage in transactions with our affiliates.

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 future indebtedness. Conversely, an event of default or an acceleration under any 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;

- 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.

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.

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, 2013 would cost us approximately \$750,000 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 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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Leasehold Properties

As of December 31, 2013, our principal assets included approximately 187,044 net acres located in the northern region of the United States. Net acreage represents our percentage ownership of gross acreage. The following table summarizes our estimated gross and net developed and undeveloped acreage by state at December 31, 2013.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota:						
Mountrail County	112,222	25,325	25,574	7,699	137,796	33,024
Dunn County	55,534	13,791	32,770	15,926	88,304	29,717
McKenzie County	65,579	18,194	27,931	7,301	93,510	25,495
Divide County	51,026	14,302	5,815	3,857	56,841	18,159
Williams County	54,520	15,118	7,260	1,549	61,780	16,667
Other	69,959	11,475	60,973	10,798	130,932	22,273
North Dakota	408,840	98,205	160,323	47,130	569,163	145,335
Montana	36,450	9,794	105,400	31,915	141,850	41,709

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Total:	445,290	107,999	265,723	79,045	711,013	187,044
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At 2013 year end, approximately 58% of our total acreage was developed. In addition, approximately 63% of our total acreage position was either developed, held by production or held by operations as of December 31, 2013. All of our proved reserves are located in North Dakota and Montana.

Recent Acquisitions

In 2013, we acquired leasehold interests covering an aggregate of approximately 20,900 net acres in our key prospect areas, for an average cost of \$1,279 per net acre. In addition, during 2013 we separately acquired working interests in 70 gross (7.0 net) wells in undrilled locations in which we do not hold the underlying leasehold interests, for a total cost of approximately \$9.0 million. During 2012, we acquired approximately 17,590 net acres at an average cost of \$1,788 per acre, and earned an additional 6,450 net acres through farm-in arrangements.

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 gross and net acres which are subject to expire between 2014 and 2018 and thereafter, are set forth below:

Year Ended	Acreage Subject to Expiration	
	Gross	Net
December 31, 2014	66,144	24,085
December 31, 2015	93,707	21,998
December 31, 2016	42,334	14,656
December 31, 2017	1,716	1,006
December 31, 2018 and thereafter	16,889	10,672
Total	220,790	72,417

During 2013, we had leases expire in Montana and North Dakota covering approximately 13,129 net acres, all of which was prospective for the Bakken and Three Forks Formations. The 2013 lease expirations carried a \$14.1 million cost that was transferred to the costs subject to depletion. 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 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.

Production History

The following table presents information about our produced oil and natural gas volumes during the years ended December 31, 2013, 2012 and 2011. As of December 31, 2013, we were selling oil and natural gas from a total of 1,758 gross (146.2 net) wells. As of December 31, 2012, we were selling oil and natural gas from a total of 1,227 gross (106.2 net) wells. As of December 31, 2011, we were selling oil and natural gas from a total of 664 gross (57.9 net) wells. All of the foregoing wells were located within the Williston Basin. All data presented below is derived from accrued revenue and production volumes for the relevant period indicated.

	Year Ended December 31,		
	2013	2012	2011
Net Production:			
Oil (Bbl)	4,046,701	3,465,311	1,791,979
Natural Gas and NGLs (Mcf)	2,572,251	1,768,872	800,207
Barrels of Oil Equivalent (Boe)	4,475,409	3,760,123	1,925,347
Average Sales Prices:			
Oil (per Bbl)	\$87.90	\$83.22	\$86.01
Effect of Loss on Settled Derivatives on Average Price (per Bbl)	(3.01)	(0.11)	(7.48)
Oil Net of Settled Derivatives (per Bbl)	84.89	83.11	78.53
Natural Gas and NGLs (per Mcf)	5.24	4.67	6.63
Realized Price on a Boe Basis Including All Realized Derivative Settlements	79.77	78.79	75.85
Average Costs:			
Production Expenses (per Boe)	\$9.35	\$8.61	\$6.77

Depletion of Oil and Natural Gas Properties

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 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Depletion of Oil and Natural Gas Properties	\$123,628,635	\$98,427,159	\$40,815,426
Depletion Expense (per Boe)	\$27.62	\$26.18	\$21.20

Drilling and Development Activity

The following table sets forth the number of gross and net productive and non-productive wells for all of our drilling and development activity in the years ended December 31, 2013, 2012 and 2011. The following table does not

include wells that were awaiting completion, in the process of completion or awaiting flowback subsequent to fracture stimulation. We have not participated in any wells solely targeting natural gas reserves. We have classified all wells drilled to-date targeting the Bakken and Three Forks formations as development wells.

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Oil	–	–	–	–	1	–
Natural Gas	–	–	–	–	–	–
Non-Productive	–	–	–	–	1	0.3
Development Wells:						
Oil	531	40.0	563	48.3	353	32.3
Natural Gas	–	–	–	–	–	–
Non-Productive	–	–	–	–	–	–
Total Productive Exploratory and Development Wells	531	40.0	563	48.3	354	32.3

The following table summarizes our cumulative gross and net productive oil wells by state at each of December 31, 2013, 2012 and 2011.

	At December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	1,672	134.7	1,173	97.9	642	54.4
Montana	86	11.5	54	8.3	22	3.5
Total	1,758	146.2	1,227	106.2	664	57.9

Research and Development

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

Proved Reserves

We recently completed our most current reservoir engineering calculation as of December 31, 2013.

Based on the results of our December 31, 2013 reserve analysis, our proved reserves increased approximately 25% during 2013 primarily as a result of drilling activity involving our acreage and our acquisition of acreage subject to specific drilling projects or included in permitted or drilling spacing units. We incurred approximately \$389.5 million of capital expenditures for drilling activities and \$29.4 million for acreage and other expenditures during the year ended December 31, 2013, all of which directly contributed to the increase in our proved developed reserves. No other expenditures materially contributed to the development of proved developed reserves in 2013. Our proved undeveloped reserves increased by approximately 30% during 2013 primarily as a result of drilling activity and our acquisitions of acreage. We estimate that approximately 14% of our proved undeveloped reserves, as of December 31, 2012, were converted to proved developed reserves during 2013. Our development drilling program includes the drilling of approximately 144.5 proven undeveloped net wells before the end of 2018 at an estimated cost of \$1.2 billion. Our development plan for drilling proved undeveloped wells calls for the drilling of 30.7 net wells during 2014, 27.4 net wells during 2015, 27.7 net wells during 2016, 28.6 net wells during 2017, and 30.1 net wells during 2018, for a total of 144.5 net wells. During 2013, our progress toward converting proved undeveloped reserves to proved developed reserves included the drilling and completion of 11.1 net undeveloped wells at a total estimated net

capital cost of \$116.9 million. 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.

During 2013, we had a negative revision of 9.8 MMBoe, or 26%, of our December 31, 2012 estimated proved undeveloped reserves balance. The primary cause for these revisions was negative well performances. Within portions of our areas of operation, actual well results underperformed relative to the proved undeveloped forecasts in our December 31, 2012 reserve report. The proved undeveloped forecasts in these areas have been adjusted to reflect these well performances in our December 31, 2013 reserve report. A reconciliation of the change in proved undeveloped reserves during 2013 is as follows:

	MMBoe
Estimated Proved Undeveloped Reserves at 12-31-2012	37.4
PUD's converted to PDP's during 2013	(5.2)
Additional PUD's added during 2013	26.3
Revisions of previous estimates	(9.8)
Estimated Proved Undeveloped reserves at 12-31-2013	48.7

Preparation of our reserve report is outlined in our Sarbanes-Oxley Act Section 404 internal control procedures. Our procedures require that our reserve report be prepared by a third-party registered independent engineering firm at the end of every year based on information we provide to such engineer. We utilize historical production and expense data for our wells, calculate historical differentials, validate working interests and net revenue interests, and obtain updated authorizations for expenditure ("AFEs") from our operations department. This data is forwarded to our third-party engineering firm for review and calculation. Our Chief Executive Officer provides a final review of our reserve report and the assumptions relied upon in such report.

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.

We employ two internal reserve engineers who are responsible for overseeing the preparation of our reserves estimates. One of the internal reserve engineers has a B.S. in chemical and petroleum engineering from the University of Pittsburgh and has twelve years of oil and gas experience on the reservoir side. The other internal reserve engineer has a B.S. in petroleum engineering from Montana Tech and has eight years of oil and gas experience on the reservoir side. Our engineers have experience working for large independents and financial firms on projects and acquisitions, both domestic and international. The proved reserves tables below summarize our estimated proved reserves as of December 31, 2013, based upon reports prepared by Ryder Scott. 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.”

Ryder Scott prepared our reserve report valuing our proved reserves at December 31, 2013. The report values only our proved reserves and does not value our probable reserves or our possible reserves. The following table sets forth our estimated proved reserves based on the SEC rules as defined in Rule 4.10(a) of Regulation S-X and Item 1200 of Regulation S-K (“SEC Pricing Proved Reserves”).

SEC Pricing Proved Reserves(1)

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)(2)	Pre-Tax PV10% Value \$(3)
PDP Properties	26,150	16,538	28,906	\$881,698
PDNP Properties	5,893	4,105	6,577	151,080
PUD Properties	43,756	29,525	48,677	488,511
Total Proved Properties:	75,799	50,168	84,160	\$1,521,289

(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, 2013 assuming constant realized prices of \$88.00 per barrel of oil and

\$5.23 per Mcf of natural gas, which includes an uplift factor of 1.4 to reflect liquids and condensates (natural gas liquids are included with 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, which averages are then adjusted to reflect applicable transportation and quality differentials.

- (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% 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. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe Pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our Pre-tax PV10% as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and natural gas properties and acquisitions. However, Pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our Pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

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 “Pre-tax PV10%” values of our proved reserves presented in the foregoing table may be considered a non-GAAP financial measure as defined by the SEC. The following table reconciles the pre-tax PV10% value of our SEC Pricing Proved Reserves 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%)	\$1,521,289
Future income taxes, discounted at 10%	296,923
Standardized measure of discounted future net cash flows	\$1,224,367

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” to our financial statements included later in this report.

Delivery Commitments

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

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.

Item 4. Mine Safety Disclosures

None.

Executive Officers of the Registrant

Our executive officers, their ages and offices held are as follows:

Name	Age	Positions
Michael L. Reger	37	Chairman, Chief Executive Officer and Director
Thomas W. Stoelk	58	Chief Financial Officer
Brandon R. Elliott	42	Executive Vice President, Corporate Development and Strategy
Erik J. Romslo	36	Executive Vice President, General Counsel and Secretary

Michael L. Reger is a founder of our predecessor, Northern Oil and Gas, Inc., and has served as Chairman of the Board and Chief Executive Officer of our company since March 2007. Mr. Reger has been involved in the acquisition of oil and gas mineral rights for his entire career. Mr. Reger began working the oil and gas leasing business for his family's company, Reger Oil, in 1992 and worked as an oil and gas landman for Reger Oil from 1992 until co-founding Northern in 2006. Mr. Reger holds a B.A. in Finance and an M.B.A. in finance/management from the University of St. Thomas in St. Paul, Minnesota. The Reger family has a history of acreage acquisition in the Williston Basin dating to 1952.

Thomas W. Stoelk has served as our Chief Financial Officer since December 2011. Prior to joining our company, Mr. Stoelk served as the Vice President of Finance and Chief Financial Officer at Superior Well Services, Inc. from 2005 to 2011. Prior to Superior Well Services, Inc., Mr. Stoelk served as the Chief Financial Officer of Great Lakes Energy Partners, LLC from 1999 to 2005 and the Senior Vice President of Finance and Administration for Range Resources Corporation from 1994 to 1999. Prior to his employment with Range Resources Corporation, Mr. Stoelk was a senior manager at Ernst & Young LLP and worked as a certified public accountant in their auditing practice. Mr. Stoelk holds a BS in Industrial Administration from Iowa State University.

Brandon R. Elliott has served as our Executive Vice President, Corporate Development and Strategy since January 2013. Prior to joining our company, Mr. Elliott served as Vice President of Investor Relations of CONSOL Energy Inc., a Fortune 500 coal and natural gas company, from 2010 until 2012. Prior to CONSOL, Mr. Elliott worked from 2000 until 2010 at Friess Associates LLC, managers of The Brandywine Funds, most recently as a portfolio manager. Mr. Elliott holds a bachelor's degree from Dartmouth College, is a Chartered Financial Analyst (CFA) and is a member of the National Investor Relations Institute.

Erik J. Romslo has served as our General Counsel and Secretary since October 2011 and as an Executive Vice President since January 2013. Prior to joining our company, Mr. Romslo practiced law in the Minneapolis office of our outside counsel, Faegre Baker Daniels LLP (formerly Faegre & Benson LLP), from 2005 until 2011, where he was a member of the Corporate group. Prior to joining Faegre, Mr. Romslo practiced law in the New York City office of Fried, Frank, Harris, Shriver & Jacobson LLP. Mr. Romslo holds a bachelor's degree from St. Olaf College and a law degree from the New York University School of Law.

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 2012 and 2013 are set forth below.

	Sales Price	
	High	Low
Fiscal Year Ended December 31, 2012		
First Quarter	\$28.00	\$20.04
Second Quarter	21.40	14.94
Third Quarter	19.70	14.40
Fourth Quarter	17.88	13.73
Fiscal Year Ended December 31, 2013		
First Quarter	\$17.55	\$13.15
Second Quarter	14.99	12.00
Third Quarter	14.85	11.79
Fourth Quarter	17.90	13.97

The closing price for our common stock on the NYSE MKT on February 18, 2014 was \$15.77 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, 2008, 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, 2008 to December 31, 2013.

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

	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13
Northern Oil & Gas, Inc.	\$100.00	\$455.38	\$1,046.54	\$922.31	\$646.92	\$579.62
S&P 500	100.00	126.46	145.51	148.59	172.37	228.19
NYSE Arca Oil Index	100.00	113.19	119.67	127.72	130.22	154.19

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

Holdings

As of February 1, 2014, we had 61,852,670 shares of our common stock outstanding, held by approximately 358 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

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 prohibited from paying 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, 2013.

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)
Month #1				\$
October 1, 2013 to October 31, 2013	694	\$ 15.63	-	123.9 million
Month #2				
November 1, 2013 to November 30, 2013	-	-	-	123.9 million
Month #3				

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December 1, 2013 to December 31, 2013	15,058	15.30	-	123.9 million
				\$
Total	15,752	\$ 15.32	-	123.9 million

- (1) All shares purchased reflect shares surrendered by company directors or employees as payment of exercise price for stock options exercised or in satisfaction of tax obligations in connection with restricted stock awards.
- (2) In May 2011, our board of directors approved a stock repurchase program to acquire up to \$150 million shares of our company's outstanding common stock. We have repurchased 2,036,383 shares under this program through December 31, 2013 at an average price of \$12.82 per share.

Item 6. Selected Financial Data

	Fiscal Years				
	2013	2012	2011	2010	2009
	(in thousands, except share and per common share data)				
Statements of Income Information:					
Revenues					
Oil and Gas Sales	\$369,187	\$296,638	\$159,440	\$59,488	\$15,172
(Loss) Gain on Settled Derivatives	(12,199)	(391)	(13,408)	(470)	(625)
(Loss) Gain on the Mark-to-Market of Derivative Instruments	(21,259)	15,147	3,072	(14,545)	(363)
Other Revenue	44	179	285	86	38
Total Revenues	335,773	311,573	149,389	44,559	14,222
Operating Expenses					
Production Expenses	41,859	32,382	13,044	3,288	755
Production Taxes	34,959	28,486	14,301	5,478	1,300
General and Administrative Expense	16,575	22,645	13,625	7,204	3,686
Depletion, Depreciation, Amortization and Accretion	124,383	98,923	41,169	17,084	4,351
Total Expenses	217,776	182,436	82,139	33,054	10,092
Income from Operations	117,997	129,137	67,250	11,505	4,130
Other Income (Expense)	(453)	25	783	414	671
Interest Expense, Net of Capitalization	(32,709)	(13,875)	(586)	(583)	(535)
Total Other Income (Expense)	(33,162)	(13,850)	197	(169)	136
Income Before Income Taxes	84,835	115,287	67,447	11,336	4,266
Income Tax Provision	31,768	43,002	26,835	4,419	1,466
Net Income	\$53,067	\$72,285	\$40,612	\$6,917	\$2,800
Net Income Per Common Share – Basic	\$0.85	\$1.16	\$0.66	\$0.14	\$0.08
Net Income Per Common Share – Diluted	\$0.85	\$1.15	\$0.65	\$0.14	\$0.08
Weighted Average Shares Outstanding – Basic	62,364,957	62,485,836	61,789,289	50,387,203	36,705,267
Weighted Average Shares Outstanding – Diluted	62,747,298	62,869,079	62,195,340	50,778,245	36,877,070
Statements of Cash Flows Information:					
Net Cash Provided By Operating Activities	\$222,774	\$198,527	\$85,150	\$73,307	\$9,813

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Net Cash Used For Investing Activities	\$(358,536)	\$(532,172)	\$(300,868)	\$(207,893)	\$(71,849)
Net Cash Provided By Financing Activities	\$128,061	\$340,754	\$69,887	\$280,464	\$67,488

Balance Sheet Information:

Assets:

Cash and Cash Equivalents	\$5,687	\$13,388	\$6,280	\$152,111	\$6,233
Total Current Assets	104,388	94,215	80,505	233,018	42,018
Property and Equipment, net	1,397,307	1,083,245	643,703	275,308	92,150
Total Assets	1,519,600	1,190,935	725,594	509,694	135,595

Liabilities:

Total Current Liabilities	194,088	100,457	119,661	59,667	8,910
Revolving Line of Credit	75,000	124,000	69,900	-	-
8% Senior Notes Due 2020, Net	509,540	300,000	-	-	-
Total Liabilities	899,772	604,750	229,024	74,334	12,036
Total Shareholders' Equity	619,828	586,185	496,570	435,360	123,559

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 2013 Results

During 2013, we achieved the following financial and operating results:

- Increased total production by 19% compared to 2012;
- Increased total estimated proved reserves to 84.2 million Boe as of December 31, 2013, an increase of 25% compared to 2012 year-end;
 - Participated in the completion of 531 gross (40.0 net) wells;
- Continued to high-grade and grow our leasehold position to 187,044 net acres with approximately 63% of our total acreage position either developed, held by production or held by operations as of December 31, 2013; and
- Ended the year with \$6 million in cash and, including availability under our revolving credit facility, liquidity of approximately \$381 million.

Operationally, our 2013 performance reflects another year of successfully executing our strategy of developing our acreage position and building a long-life reserve base. Our success enabled us to increase proved reserves by 16.6 million Boe, which is approximately 3.7 times our 2013 production. During 2013, production increased 19% to 4.5 million Boe as compared to 2012 production of 3.8 million Boe. The increase in 2013 production was driven by a 38% increase in producing net wells from 106.2 net wells at December 31, 2012 to 146.2 net wells at December 31, 2013.

Total revenues increased 8% or \$24.2 million in 2013 compared to 2012. This increase was due to higher production levels that generated \$72.5 million in oil and gas revenue growth, which was partially offset by a \$12.2 million loss on settled derivatives and a \$21.3 million loss on the mark-to-market of derivative instruments. Average realized prices on a Boe basis (including all realized derivative settlements) were 1% higher in 2013 compared to 2012. As discussed elsewhere in this report, significant changes in oil and natural gas prices can have a material impact on our results of operations and our balance sheet, including the fair value of our derivatives.

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.
- (Loss) gain on the mark-to-market of derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. This account activity represents the recognition of gains and losses associated with our outstanding derivative contracts as commodity prices and commodity derivative contracts change on contracts that have not been designated for hedge accounting.
- Realized gain (loss) on derivative instruments. This account activity represents our realized gains and losses on the settlement of commodity derivative instruments.
- 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 and amortization. Depreciation, depletion and amortization 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.
- Income tax expense. Our provision for taxes includes both federal and state taxes. We account for income taxes using the asset and liability method, which requires 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 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
 - 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 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 been high enough to justify shipment by rail to markets, such as St. James, Louisiana, which offer 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.

Over the past several years, oil production in the Williston Basin has increased dramatically. For example, North Dakota's oil production in October 2013 was up approximately 93% as compared to October 2011. The surging oil production has created a huge need for oil takeaway infrastructure, which has struggled to keep pace with the growth in production. This caused the price of Bakken crude to lag significantly behind WTI crude at certain times over the last few years. In response to rapidly rising production, rail capacity out of the area has greatly expanded, which has allowed Bakken crude to reach refining markets on the East Coast, West Coast and Gulf Coast. As the takeaway solution developed, the Bakken crude differential to WTI in 2013 has lowered, and even traded at points at a premium to WTI. During the fourth quarter of 2013, our crude differential widened to approximately \$14.98 per barrel due to several factors such as takeaway capacity lagging behind production, 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 return to historical levels. Our weighted average oil price differential to the NYMEX WTI benchmark price during 2013 was approximately \$8.68 per barrel, as compared to \$9.79 per barrel in 2012.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells has increased significantly over the past few years as rising oil prices have triggered increased drilling activity in the Williston Basin. Although 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), the total cost of drilling and completing an oil well has increased. This increase is largely due to longer horizontal laterals and more fracture stimulation stages, but also higher demand for rigs and completion services throughout the region. In addition, because of the rapid growth in drilling, the availability of well completion services has at times been

constrained, resulting at times in a backlog of wells awaiting completion.

Market Conditions

Prices for various quantities of oil, natural gas, and NGLs that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following tables list average NYMEX prices for oil and natural gas for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Average NYMEX prices(1)			
Oil (per Bbl)	\$98.05	\$94.15	\$95.11
Natural Gas (per Mcf)	\$3.73	\$2.83	\$4.03

(1) Based on average of daily closing prices.

Results of Operations for 2013, 2012 and 2011

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

	Year Ended December 31,		
	2013	2012	2011
Net Production:			
Oil (Bbl)	4,046,701	3,465,311	1,791,979
Natural Gas and NGLs (Mcf)	2,572,251	1,768,872	800,207
Total (Boe)(1)	4,475,409	3,760,123	1,925,347
Net Sales (in thousands):			
Oil Sales	\$355,702	\$288,382	\$154,133
Natural Gas and NGL Sales	13,485	8,256	5,307
Loss on Settled Derivatives	(12,199)	(391)	(13,408)
(Loss) Gain on the Mark-to-Market of Derivative Instruments	(21,259)	15,147	3,072
Other Revenue	44	179	285
Total Revenues	335,773	311,573	149,389
Average Sales Prices:			
Oil (per Bbl)	\$87.90	\$83.22	\$86.01
Effect of Loss on Settled Derivatives on Average Price (per Bbl)	(3.01)	(0.11)	(7.48)
Oil Net of Settled Derivatives (per Bbl)	84.89	83.11	78.53
Natural Gas and NGLs (per Mcf)	5.24	4.67	6.63
Realized price on a Boe basis including all realized derivative settlements(2)	79.77	78.79	75.85
Operating Expenses (in thousands):			
Production Expenses	\$41,859	\$32,382	\$13,044
Production Taxes	34,959	28,486	14,301
General and Administrative Expense (Including Non-Cash Stock Based Compensation)	16,575	22,645	13,625
Depletion of Oil and Gas Properties	124,383	98,427	40,815

(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.

(2) Realized prices include realized gains and losses on cash settlements for commodity derivatives.

Oil, Natural Gas and NGL Sales

Our revenues vary from year to year primarily as a result of changes in realized commodity prices and production volumes. In 2013, oil, natural gas and NGL sales increased 24% from 2012, driven primarily by a 19% increase in production and partially aided by a 5% increase in our average sales price per Boe in 2013 as compared to 2012. In 2012, oil, natural gas and NGL sales increased 86% from 2011 due to a 95% increase in production, partially offset by a 4% decrease in our average sales price per Boe in 2012 as compared to 2011.

Our production continues to grow through drilling success as we place new wells into production and through additions from acquisitions, partially offset by the natural decline of our production from existing wells. Our production primarily increased due to the addition of 40.0 and 48.3 net productive wells in 2013 and 2012, respectively. Our production for each of the last three years is set forth in the following table:

	Year Ended		
	2013	2012	2011
Production			
Oil (Bbl)	4,046,701	3,465,311	1,791,979
Natural Gas and NGL (Mcf)	2,572,251	1,768,872	800,207
Total (Boe)(1)	4,475,409	3,760,123	1,925,347
Average Daily Production			
Oil (Bbl)	11,087	9,468	4,910
Natural Gas and NGL (Mcf)	7,047	4,833	2,192
Total (Boe)(1)	12,261	10,274	5,275

(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. For 2013, we incurred a loss on settled derivatives of \$12.2 million, compared to losses of \$0.4 million in 2012 and \$13.4 million in 2011. Our average realized price (including all derivative settlements) received during 2013 was \$79.77 per Boe compared to \$78.79 per Boe in 2012 and \$75.85 per Boe in 2011.

Mark-to-market derivative gains and losses was a loss of \$21.3 million in 2013 compared to a \$15.1 million gain in 2012 and a \$3.1 million loss in 2011. 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, 2013, all of our derivative contracts are recorded at their fair value, which was a net liability of \$17.9 million, a decrease of \$21.2 million from the \$3.3 million net asset recorded as of December 31, 2012. 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 \$41.9 million in 2013 compared to \$32.4 million in 2012 and \$13.0 million in 2011. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses increased from \$8.61 per Boe in 2012 to \$9.35 per Boe in 2013. On an absolute dollar basis, our production expenses in 2013 were 29% higher when compared to the same period in 2012 due primarily to a 19% increase in production levels and a 38% increase in the total number of net wells. Also contributing to the increase were increased water production and costs associated with more workover, repair and maintenance and salt water trucking and disposal activities during 2013 as compared to 2012. On a per unit basis, production expenses per Boe increased from \$6.77 per barrel sold in 2011 to \$8.61 in 2012. On an absolute dollar basis, our spending for production expenses for 2012 was 148% higher when compared to 2011 due to production levels increasing 95%, as well as higher water hauling and disposal costs and higher servicing expenses.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. These costs were \$35.0 million in 2013 compared to \$28.5 million in 2012 and \$14.3 million in 2011. Our average production tax rates were 9.5%, 9.6% and 9.0% in 2013, 2012 and 2011, respectively. The 2013 average production tax rate was lower than the 2012 average due to well additions that qualified for reduced rates/or tax exemptions during 2013. Certain portions of our production occurs in Montana and North Dakota jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate. The 2012 average production tax rate was higher than the 2011 average due to fewer well additions that qualified for reduced rates for tax exemptions during 2012. The majority of our production is located in North Dakota which imposes a standard 11.5% tax on our production revenues except for where properties qualify for reduced rates.

General and Administrative Expense

General and administrative expense was \$16.6 million for 2013 compared to \$22.6 million for 2012 and \$13.6 million in 2011. The \$6.0 million decrease in 2013 when compared to 2012 was primarily due to \$5.5 million of severance charges recognized in 2012 in connection with the departures of our former president and our former chief operating officer. Additionally, salaries and benefit expenses decreased \$1.5 million in 2013 as compared to 2012, which was partially offset by increased insurance (\$0.6 million) and legal and professional (\$0.2 million) expenses. Lower share based compensation in 2013 drove the year over year drop in salary and benefit expenses. The 2012 increase of \$9.0 million when compared to 2011 is due to higher salary and benefit expenses (\$3.6 million), increased travel expenses (\$0.2 million) and partially offset by lower office and other administrative expenses (\$0.3 million). Our personnel costs in 2012 as compared to 2011 continued to increase as we invested in our technical teams and other staffing to support our growth. Additionally, 2012 general and administrative expenses include \$5.5 million of severance charges in connection with the departures of our former president and former chief operating officer.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was \$124.4 million in 2013 compared to \$98.9 million in 2012 and \$41.2 million in 2011. Depletion expense, the largest component of DD&A, was \$27.62 per Boe in 2013 compared to \$26.18 per Boe in 2012 and \$21.20 per Boe in 2011. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. The aggregate increase in depletion expense for 2013 compared to 2012 was driven by a 19% increase in production. Additionally, depletion rates rose in

2013 primarily due to higher production expenses and revised reserve estimates in certain of our areas of operation. Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. As these plays mature, new technologies, well completion methodologies and additional historical operating information impact the reserve evaluations. The aggregate increase in depletion expense for 2012 compared to 2011 was driven by a 95% increase in production. Depreciation, amortization and accretion was \$0.8 million in 2013 compared to \$0.5 million in 2012 and \$0.4 million in 2011. The following table summarizes DD&A expense per Boe for 2013, 2012 and 2011:

	Year Ended December 31,					Year Ended December 31,				
	2013	2012	Change	Change		2012	2011	Change	Change	
Depletion	\$27.62	\$26.18	\$1.44	6	%	\$26.18	\$21.20	\$4.98	23	%
Depreciation, amortization, and accretion	0.17	0.13	0.04	31	%	0.13	0.18	(0.05)	(28)	%
Total DD&A expense	\$27.79	\$26.31	\$1.48	6	%	\$26.31	\$21.38	\$4.93	23	%

Interest Expense

Interest expense was \$32.7 million for 2013 compared to \$13.9 million in 2012. Interest expense was \$13.9 million for 2012 compared to \$0.6 million in 2011. In May 2013 and 2012, we issued \$200 million and \$300 million of 8% senior unsecured notes, respectively. The increase in interest expense for 2013 as compared to 2012 was primarily due to different weighted average debt amounts outstanding between years. The increase in interest expense for 2012 as compared to 2011 was primarily due to different weighted average debt amounts outstanding between years, as well as the higher interest rate applicable to the senior notes.

Interest Income

Interest income was \$21,000 for 2013 compared to \$1,000 in 2012. Interest income was comparable between periods due to similar levels of cash and short term investments. Interest income was \$1,000 for 2012 compared to \$0.6 million in 2011. Interest income for 2012 decreased \$0.6 million as compared to 2011 because of lower levels of cash and short term investments. In 2011, the higher amount of cash and short term investments resulted from proceeds from the sale of common stock in November 2010.

Income Tax Provision

The provision for income taxes was \$31.8 million in 2013 compared to \$43.0 million in 2012 and \$26.8 million in 2011. The effective tax rate in 2013 was 37.4% compared to an effective tax rate of 37.3% in 2012. The effective tax rate was different than the statutory rate of 35% primarily due to state tax rates. The 2012 effective tax rate was 37.3% compared to an effective tax rate in 2011 of 39.8%. Due to higher pre-tax income levels, we increased our federal statutory rate from 34% to 35% in 2011. The effective tax rate was different than the statutory rate of 35% primarily due to state tax rates.

Net Income

Net income was \$53.1 million in 2013 compared to \$72.3 million in 2012 and \$40.6 million in 2011. The increase in net income in 2012 as compared to 2011 was driven by higher production levels and higher average sales prices received in 2012 compared to 2011. The decrease in net income in 2013 as compared to 2012 was driven by 2013 losses on settled derivatives and losses on the mark-to-market of derivative instruments of \$12.2 million and \$21.3 million, respectively. In 2012, our loss on settled derivatives was \$0.4 million and our gain on the mark-to-market of derivative instruments was \$15.1 million. Additionally, the higher oil and gas revenues in 2013 were partially offset by increased production expenses, production taxes, depletion expenses, and interest expense in 2013 compared to 2012. Our net income translated to diluted net income per common share of \$0.85, \$1.15 and \$0.65 in 2013, 2012 and 2011, respectively.

Non-GAAP Financial Measures

We define Adjusted Net Income as net income excluding (i) loss (gain) on the mark-to-market of derivative instruments, net of tax and (ii) severance expenses in connection with the departures of our former president and former chief operating officer, net of tax. Our Adjusted Net Income for the year ended December 31, 2013, was \$66.4 million (representing approximately \$1.06 per diluted share), as compared to \$66.2 million (representing approximately \$1.05 per diluted share) for the year ended December 31, 2012, and \$38.8 million (representing approximately \$0.62 per diluted share) for the year ended December 31, 2011. These increases in Adjusted Net Income are primarily due to our continued addition of oil and natural gas production from new wells and higher realized commodity prices in 2013 compared to 2012 and in 2012 compared to 2011.

We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) loss (gain) on the mark-to-market of derivative instruments and (v) non-cash share based compensation expense. Adjusted EBITDA for the year ended December 31, 2013 was \$268.0 million, compared to Adjusted EBITDA of \$225.3 million for the year ended December 31, 2012 and \$112.3 million for the year ended December 31, 2011. These increases in Adjusted EBITDA are primarily due to our continued addition of oil and natural gas production from new wells and higher realized commodity prices in 2013 compared to 2012 and in 2012 compared to 2011.

We believe the use of these non-GAAP financial measures provides useful information to investors to gain an overall understanding of our current financial performance. Specifically, we believe the non-GAAP financial measures included herein provide useful information to both management and investors by excluding certain expenses and unrealized commodity gains and losses that our management believes are not indicative of our core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring our performance, and we believe that we are providing investors with financial measures that most closely align to our internal measurement processes. We consider these non-GAAP measures to be useful in evaluating our core operating results as they more closely reflect our essential revenue generating activities and direct operating expenses (resulting in cash expenditures) needed to perform these revenue generating activities. Our management also believes, based on feedback provided by the investment community, that the non-GAAP financial measures are necessary to allow the investment community to construct its valuation models to better compare our results with our competitors and market sector.

These measures should be considered in addition to results prepared in accordance with GAAP. In addition, these non-GAAP financial measures are not based on any comprehensive set of accounting rules or principles. We believe that non-GAAP financial measures have limitations in that they do not reflect all of the amounts associated with our results of operations as determined in accordance with GAAP and that these measures should only be used to evaluate our results of operations in conjunction with the corresponding GAAP financial measures.

Adjusted Net income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

NORTHERN OIL AND GAS, INC.
Reconciliation of GAAP Net Income to Adjusted Net Income

	Year Ended December 31		
	2013	2012	2011
(in thousands, except share and per common share data)			
Net Income	\$53,067	\$72,285	\$40,611
Add:			
Loss (Gain) on the Mark-to-Market of Derivative Instruments, Net of Tax (a)	13,300	(9,497)	(1,849)
Severance Expense, Net of Tax (b)	-	3,425	-
Adjusted Net Income	\$66,367	\$66,213	\$38,762
Weighted Average Shares Outstanding – Basic	62,364,957	62,485,836	61,789,289
Weighted Average Shares Outstanding – Diluted	62,747,298	62,869,079	62,195,340
Net Income Per Common Share – Basic	\$0.85	\$1.16	\$0.66
Add:			
Change due to Loss (Gain) on the Mark-to-Market of Derivative Instruments, Net of Tax	0.21	(0.15)	(0.03)
Change due to Severance Expense, Net of Tax	-	0.05	-
Adjusted Net Income Per Common Share – Basic	\$1.06	\$1.06	\$0.63
Net Income Per Common Share – Diluted	\$0.85	\$1.15	\$0.65
Add:			
Change due to Loss (Gain) on the Mark-to-Market of Derivative Instruments, Net of Tax	0.21	(0.15)	(0.03)
Change due to Severance Expense, Net of Tax	-	0.05	-
Adjusted Net Income Per Common Share – Diluted	\$1.06	\$1.05	\$0.62

(a) Adjusted to reflect related tax benefit (expense) of \$8.0 million, (\$5.6 million) and (\$1.2 million) for the years ended December 31, 2013, 2012 and 2011 respectively.

(b) Reflects severance expense recognized in connection with the departures during 2012 of our former president and former chief operating officer. Adjusted to reflect related tax benefit of \$2.0 million, for the year ended December 31, 2012.

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net Income	\$53,067	\$72,285	\$40,611
Add Back:			
Interest Expense	32,709	13,875	586
Income Tax Provision	31,768	43,002	26,835
Depreciation, Depletion, Amortization and Accretion	124,383	98,923	41,170
Non-Cash Share Based Compensation	4,799	12,382	6,164
Loss (Gain) on the Mark-to-Market of Derivative Instruments	21,259	(15,147)	(3,072)
Adjusted EBITDA	\$267,985	\$225,320	\$112,294

2014 Operation Plan

We expect our total 2014 capital expenditure budget to range between \$430 million and \$440 million. Our 2014 budget anticipates we will participate in the drilling and completion of approximately 44 net wells targeting the Bakken and Three Forks formations at an estimated cost of approximately \$388 million. Based on evolving conditions in the field, we expect our spending to range between \$30 million and \$40 million on acreage and other expenditures during 2014. In addition, we estimate that we will spend approximately \$12 million on other capital expenditure activities, primarily capitalized workover expenses. We have the ability to adjust capital expenditures by reducing the number of projects we elect to participate in. We currently expect to fund all 2014 commitments using a combination of cash-on-hand, cash flow generated by operations, bank borrowings and potential debt financings.

Liquidity and Capital Resources

Overview

Historically, our main sources of liquidity and capital resources have been internally generated cash flow from operations, credit facility borrowings and issuances of debt and equity. We generally maintain low cash and cash equivalent balances because we use cash from operations to fund our development activities or reduce our bank debt. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In February 2012, we amended and restated the credit agreement governing our revolving credit facility (the "Revolving Credit Facility") to increase the maximum facility size to \$750 million, subject to a borrowing base that is currently \$450 million. In May 2012, we issued \$300 million aggregate principal amount, and in May 2013, we issued an additional \$200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (collectively the "Notes").

With our Revolving Credit Facility and our anticipated cash reserves and cash from operations, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months. Any significant acquisition of additional properties or significant increase in drilling activity may require us to seek additional capital. We may also choose to seek additional financing from the capital markets rather than utilize our Revolving Credit Facility to fund such activities. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

At December 31, 2013, our debt to total capitalization ratio was 48%, we had \$584.5 million of total debt outstanding, \$619.8 million of stockholders' equity, and \$5.7 million of cash on hand. Additionally, at December 31, 2013, there was \$375 million of availability under our Revolving Credit Facility. At December 31, 2012, we had \$424 million of debt outstanding, \$586.2 million of stockholders' equity, and \$13.4 million of cash on hand.

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to fund our development activities or reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our revolving credit facility. We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future oil production for the next 12 to 36 months. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under the revolving credit facility. As of December 31, 2013, we had entered into derivative agreements covering 4.0 million barrels for 2014 and 2.9 million barrels for 2015, with average floor prices of \$90.43 and \$89.02, respectively. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Our cash flows for the years ended December 31, 2013, 2012 and 2011 are presented below:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net cash provided by operating activities	\$222,774	\$198,527	\$85,150
Net cash used in investing activities	(358,536)	(532,172)	(300,868)
Net cash provided by financing activities	128,061	340,754	69,887
Net change in cash	\$(7,701)	\$7,109	\$(145,831)

Cash flows provided by operating activities

Net cash provided by operating activities was \$222.8 million, \$198.5 million and \$85.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2013 as compared to 2012 was primarily the result of a 19% increase in oil and natural gas production that drove an oil and gas sales increase of 24%. Cash flows provided by operating activities during the year ended December 31, 2012 increased compared to 2011 primarily as a result of an increase in oil and natural gas production of 95%.

Cash flows used in investing activities

We had cash flows used in investing activities of \$358.5 million, \$532.2 million and \$300.9 million during the years ended December 31, 2013, 2012 and 2011, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. Oil and gas expenditure spending decreased from \$532.2 million in 2012 to \$358.5 million in 2013, a 33% decrease that was driven by a decrease in the number of net producing well additions in 2013 as compared to 2012. In 2013, our net producing well additions totaled 40.0 as compared to 48.2 in 2012. Oil and gas expenditure spending increased from \$341.4 million in 2011 to \$532.0 million in 2012, a 56% increase that was driven by a 50% increase in the number of net producing well additions in 2012 as compared to 2011. In 2012,

our net producing well additions totaled 48.3 as compared to 32.3 in 2011. The 2012 oil and gas expenditures include approximately \$190.4 million for wells spud prior to 2012. The spending on wells spud prior to 2012 related to wells awaiting completion at December 31, 2011, as well as completion spending for wells placed into production prior to 2012.

Development and acquisition activities are highly discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns. Our capital expenditures for development and acquisition activities for the years ended December 31, 2013, 2012 and 2011 are summarized in the following table:

	Year Ended December 31,		
	2013	2012	2011
	(in millions)		
Drilling and completion costs	\$389.5	\$486.0	\$312.9
Acreage and other related activities	38.5	37.3	79.2
Other capital expenditures	11.1	14.2	21.9
Total	\$439.1	\$537.5	\$414.0

Cash flows provided by financing activities

Net cash provided by financing activities was \$128.1 million, \$340.8 million and \$69.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. For the year ended December 31, 2013 and 2012, cash sourced through financing activities was primarily provided from the issuance of senior unsecured notes and advances under our Revolving Credit Facility. The decrease in cash provided by financing activities for 2013 as compared to 2012 was attributable to a lower level of senior unsecured note issuance in 2013. Additionally, during 2013 we repurchased 2,036,383 shares of our common stock at a cost of approximately \$26.1 million and repaid \$49 million of net borrowings under our Revolving Credit Facility with proceeds from the issuance of senior unsecured notes. During 2012, net cash provided by financing activities was primarily attributable to \$300 million from the issuance of senior unsecured notes and \$54.1 million in net borrowings under our Revolving Credit Facility. We did not repurchase any shares of our common stock during 2012. Our long term debt at December 31, 2013 was \$584.5 million, which was comprised of \$509.5 million in senior unsecured notes and \$75 million of borrowings under our Revolving Credit Facility. At December 31, 2013 we had \$375 million of available borrowing capacity under our Revolving Credit Facility. For the year ended December 31, 2011, cash increases through financing activities was primarily provided by advances under our revolving credit facility.

Revolving Credit Facility

In February 2012, we entered into an amended and restated credit agreement providing for a revolving credit facility (the "Revolving Credit Facility"), which replaced our previous revolving credit facility with a syndicated facility. Our bank group is comprised of a group of commercial banks, with no single bank holding more than 12% of the total facility. The Revolving Credit Facility, which is secured by substantially all of our assets, provides for a commitment equal to the lesser of the facility amount or the borrowing base. At December 31, 2013, the facility amount was \$750 million, the borrowing base was \$450 million and there was a \$75 million outstanding balance, leaving \$375 million of borrowing capacity available under the facility. Under the terms of the Revolving Credit Facility, we may issue an unlimited amount of permitted additional indebtedness, as defined, provided that the borrowing base will be reduced by 25% of the stated amount of any such permitted additional indebtedness. The \$500 million in Notes described below is "permitted additional indebtedness" as defined in the Revolving Credit Facility.

The Revolving Credit Facility matures on September 30, 2018 and provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. Borrowings under the Revolving Credit Facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.5% to 1.5% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined) plus a spread ranging from 1.5% to 2.5%. The applicable spread at any time is dependent upon the amount of

borrowings relative to the borrowing base at such time. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of either 0.375% or 0.50%. At December 31, 2013, the commitment fee was 0.375% and the interest rate margin was 1.5% on LIBOR loans and 0.5% on base rate loans.

The Revolving Credit Facility contains negative covenants that limit our ability, among other things, to pay any cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a current ratio of no less than 1.0 to 1.0. We were in compliance with our covenants under the Revolving Credit Facility at December 31, 2013.

All of our obligations under the Revolving Credit Facility are secured by a first priority security interest in any and all of our assets.

8.000% Senior Notes due 2020

On May 18, 2012, we issued at par value \$300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Original Notes"). On May 13, 2013, we issued at a price of 105.25% an additional \$200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Follow-on Notes" and, together with the Original Notes, the "Notes"). Interest is payable on the Notes semi-annually in arrears on each June 1 and December 1. The issuance of the Original Notes resulted in net proceeds to us of approximately \$291.2 million and the issuance of the Follow-on Notes resulted in net proceeds to us of approximately \$200.1 million, which are in use to fund our exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under our Revolving Credit Facility at the time the Notes were issued).

At any time prior to June 1, 2015, we may redeem up to 35% of the Notes at a redemption price of 108% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to June 1, 2016, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, we may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June 1, 2018, plus accrued and unpaid interest to the redemption date.

The Notes are governed by an Indenture (the "Indenture") dated May 18, 2012, with Wilmington Trust, National Association, as trustee (the "Trustee").

The Indenture restricts our ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase, equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and any of our subsidiaries will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;

- failure by us to comply with our other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to our other indebtedness and certain of our subsidiaries, if any, in the aggregate principal amount of \$25 million or more;
- certain events of bankruptcy, insolvency or reorganization of our company or a significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary;
- failure by us or any significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary to pay certain final judgments aggregating in excess of \$25 million within 60 days; and
- any guarantee of the Notes by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and natural gas properties and payment of interest on outstanding indebtedness. During 2013, our acreage and development expenditures included approximately \$389.5 million of drilling, completion and capitalized workover costs, \$1.8 million related to asset retirement obligations, \$3.3 million of capitalized internal costs and \$6.0 million of capitalized interest. Also in 2013, approximately \$38.5 million was expended on acreage and other expenditures in the Williston Basin. Our 2013 capital program was funded by cash on hand, net cash flow from operations and borrowings under our Revolving Credit Facility and the Notes. Our capital expenditure budget for 2014 is discussed above under the heading “2014 Operation Plan.”

Development and acreage activities are highly discretionary, and, for the near term, we expect such activities to be maintained at levels we can fund through internal cash flow and borrowing under our Revolving Credit Facility. To the extent capital requirements exceed internal cash flow and borrowing capacity under our Revolving Credit Facility, debt may be issued to fund these requirements. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and also between our projects, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. Our future success in growing proved reserves and production may be dependent on our ability to access outside sources of capital. If internally generated cash flow and borrowing capacity is not available under our Revolving Credit Facility, we may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Satisfaction of Our Cash Obligations for the Next 12 Months

With our Revolving Credit Facility and our cash flows from operations, we believe we have sufficient capital to meet our drilling commitments and expected general and administrative expenses for the next twelve months. Nonetheless, any strategic acquisition of assets or increase in drilling activity may require us to seek additional capital. We may also choose to seek additional capital rather than utilize our credit facility or other debt instruments to fund accelerated or continued drilling at the discretion of management and depending on prevailing market conditions. We will evaluate any potential opportunities for acquisitions as they arise. However, there can be no assurance that any additional capital will be available to us on favorable terms or at all.

Over the next 24 months it is possible that our existing capital, our Revolving Credit Facility and anticipated funds from operations may not be sufficient to sustain continued acreage acquisitions and drilling activities. Consequently, we may seek additional capital in the future to fund growth and expansion through additional debt or equity financing or credit facilities. No assurance can be made that such financing would be available, and if available it may take either the form of debt or equity. In either case, the financing could have a negative impact on our financial condition and our shareholders.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and

their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Contractual Obligations and Commitments

The following table summarizes our obligations and commitments at December 31, 2013 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

Contractual Obligations	Payment due by Period				Total
	Less than 1 year	1-3 years	3-5 years	More than 5 years	
Office Lease(1)	\$278,000	\$177,000	\$-	\$-	\$455,000
Automobile Leases(2)	27,000	-	-	-	27,000
Long Term Debt(3)	-	-	75,000,000	500,000,000	575,000,000
Cash Interest Expense on Debt(4)	41,253,000	82,505,000	82,192,000	56,667,000	262,617,000
Total	\$41,558,000	\$82,682,000	\$157,192,000	\$556,667,000	\$838,099,000

(1) Office lease through 2015

(2) Automobile leases for certain executives through 2014

(3) Revolving Credit Facility and 8.000% Senior Notes due 2020 (see Note 4 to financial statements)

(4) Cash interest on Revolving Credit Facility and 8.000% Senior Notes due 2020 are estimated assuming no principal repayment until the due date

The above contractual obligations schedule does not include future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the amount and/or timing of such payments.

Critical Accounting Policies

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our financial statements in accordance with generally accepted accounting principles in the United States (GAAP), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our estimates of our proved oil and natural gas reserves, future development costs, estimates relating to certain oil and natural gas revenues and expenses and fair value of derivative instruments are the most critical to our financial statements.

Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a

function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to our properties included in the prior year's estimates. These revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in oil and natural gas prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

The estimates of our proved oil and natural gas reserves used in the preparation of our financial statements were prepared by Ryder Scott Company, our registered independent petroleum consultants, and were prepared in accordance with the rules promulgated by the SEC.

Oil and Natural Gas Properties

The method of accounting we use to account for our oil and natural gas investments determines what costs are capitalized and how these costs are ultimately matched with revenues and expensed.

We utilize the full cost method of accounting to account for our oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs that are directly attributable to the properties and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for oil and natural gas investments. The primary difference between these two methods is the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unproved properties pending determination of proved reserves. If no proved reserves are discovered, these costs are then amortized with all the costs in the full cost pool.

Capitalized amounts except unproved costs are depleted using the units of production method. The depletion expense per unit of production is the ratio of the sum of our unamortized historical costs and estimated future development costs to our proved reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting periods. For the year ended December 31, 2013, our average depletion expense per unit of production was \$27.62 per Boe. A 10% decrease in our estimated net proved reserves at December 31, 2013 would result in a \$0.94 per Boe increase in our per unit depletion.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on period-end oil and natural gas prices) of the estimated future net cash flows from our proved oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a capitalized ceiling impairment. Such costs would be charged to operations as a reduction of the carrying value of oil and natural gas properties. The risk that we will be

required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or estimations of our proved reserves are substantially reduced. A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and shareholders' equity. Once recognized, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. The risk that we will experience a ceiling test writedown increases when oil and natural gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves. As of December 31, 2013 we have not incurred a capitalized ceiling impairment charge. However, no assurance can be given that we will not experience a capitalized ceiling impairment charge in future periods. In addition, capitalized ceiling impairment charges may occur if estimates of proved hydrocarbon reserves are substantially reduced or estimates of future development costs increase significantly. See "Item 2. Properties—Proved Reserves," for a discussion of our reserve estimation assumptions.

Revenue Recognition

We derive revenue primarily from the sale of the oil and natural gas from our interests in producing wells, hence our revenue recognition policy for these sales is significant.

We recognize revenue from the sale of oil and natural gas when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable.

We use the sales method of accounting for natural gas balancing of natural gas production and would recognize a liability if the existing proved reserves were not adequate to cover the current imbalance situation. As of December 31, 2013, our natural gas production was in balance, meaning our cumulative portion of natural gas production taken and sold from wells in which we have an interest equaled our entitled interest in natural gas production from those wells.

In general, settlements for hydrocarbon sales occur around two months after the end of the month in which the oil, natural gas or other hydrocarbon products were produced. We estimate and accrue for the value of these sales using information available to us at the time our financial statements are generated. Differences are reflected in the accounting period that payments are received from the operator.

Derivative Instrument Activities

We use derivative instruments from time to time to manage market risks resulting from fluctuations in the prices of oil and natural gas. We may periodically enter into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. We have, and may continue to use exchange traded futures contracts and option contracts to hedge the delivery price of oil at a future date.

All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and unrealized gains or losses are recorded to (losses) gains on the mark-to-market of derivative instruments on the statements of comprehensive income rather than as a component of accumulated other comprehensive income. See Note 14 for a description of the derivative contracts which we executed during 2013 and 2012.

The resulting cash flows from derivatives are reported as cash flows from operating activities.

New Accounting Pronouncements

Recently Issued

Balance Sheet Offsetting— In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. These disclosure requirements do not affect the presentation of amounts in the balance sheets, and are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual reporting periods. We implemented the disclosure guidance effective January 1, 2013, and the implementation did not have a material impact on our financial statements.

Recent Accounting Pronouncements Not Yet Adopted

For a description of the accounting standards that we adopted in 2013, see Notes to Financial Statements—Note 2. Significant Accounting Policies.

Various accounting standards and interpretations were issued in 2013 with effective dates subsequent to December 31, 2013. We have evaluated the recently issued accounting pronouncements that are effective in 2014 and believe that none of them will have a material effect on our financial position, results of operations or cash flows when adopted.

Further, we are monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2014 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

Off-Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and our management believes these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue during 2013 generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil price volatility. On November 1, 2009, due to the volatility of price differentials in the Williston Basin, we de-designated all derivatives that were previously classified as cash flow hedges and we have elected not to designate any subsequent derivative contracts as accounting hedges. As such, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and mark-to-market gains or losses are recorded to (losses) gains on the mark-to-market of derivative instruments on the statements of comprehensive income rather than as a component of other comprehensive income (loss) or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production over a rolling 36 month horizon. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the

counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

The following table reflects open commodity swap contracts as of December 31, 2013, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price
Swaps-Crude Oil		
01/01/14 – 06/30/14	300,000	\$89.50
01/01/14 – 06/30/14	240,000	90.00
01/01/14 – 06/30/14	240,000	100.00
01/01/14 – 12/31/14	240,000	91.65
01/01/14 – 12/31/14	345,000	88.55
01/01/14 – 12/31/14	345,000	88.60
01/01/14 – 12/31/14	345,000	88.40
01/01/14 – 12/31/14	345,000	88.50
01/01/14 – 12/31/14	120,000	91.35
01/01/14 – 12/31/14	120,000	90.00
01/01/14 – 12/31/14	240,000	90.15
01/01/14 – 12/31/14	240,000	91.00
01/01/14 – 12/31/14	120,000	93.00
07/01/14 – 12/31/14	120,000	90.00
07/01/14 – 12/31/14	120,000	90.00
07/01/14 – 12/31/14	120,000	93.50
07/01/14 – 12/31/14	30,000	90.58
01/01/14 – 06/30/15	480,000	89.15
01/01/15 – 06/30/15	60,000	90.50
01/01/15 – 06/30/15	180,000	88.55
01/01/15 – 06/30/15	180,000	88.00
01/01/15 – 06/30/15	60,000	90.75
01/01/15 – 06/30/15	60,000	90.25
01/01/15 – 06/30/15	90,000	89.00
01/01/15 – 06/30/15	90,000	89.00
01/01/15 – 12/31/15	720,000	89.00
01/01/15 – 12/31/15	360,000	89.00
01/01/15 – 12/31/15	360,000	89.02
01/01/15 – 12/31/15	180,000	89.00
01/01/15 – 12/31/15	180,000	89.00

As of December 31, 2013, we had a total volume on open commodity swaps of 6.6 million barrels at a weighted average price of approximately \$89.84.

The following table reflects the weighted average price of open commodity swap derivative contracts as of December 31, 2013, by year with associated volumes.

Year	Weighted Average Price Of Open Commodity Swap Contracts	
	Volumes (Bbl)	Weighted Average Price

2014	3,750,000	\$90.46
2015	2,880,000	89.02

In addition to the open commodity swap contracts, we have entered into costless collar contracts. The costless collars are used to establish floor and ceiling prices on anticipated crude oil production. There were no premiums paid or received by us related to the costless collar contracts. The following table reflects open costless collar contracts as of December 31, 2013.

Term	Oil (Barrels)	Floor/Ceiling Price	Basis
Costless Collars – Crude Oil 01/01/14 – 12/31/14	240,000	\$ 90.00/\$99.05	NYMEX

Interest Rate Risk

Our long-term debt is comprised of borrowings that contain fixed and floating interest rates. The Notes bear interest at an annual fixed rate of 8% and our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. During the year ended December 31, 2013, we had \$73.5 million in average outstanding borrowings under our Revolving Credit Facility at a weighted average rate of 2.14%. We have the option to designate the reference rate of interest for each specific borrowing under the Revolving Credit Facility as amounts are advanced. Borrowings based upon the London Interbank Offered Rate (“LIBOR”) will bear interest at a rate equal to LIBOR plus a spread ranging from 1.5% to 2.5% depending on the percentage of borrowing base that is currently advanced. Any borrowings not designated as being based upon LIBOR will bear interest at a rate equal to the current prime rate published by the Wall Street Journal, plus a spread ranging from 0.5% to 1.5%, depending on the percentage of borrowing base that is currently advanced. We have the option to designate either pricing mechanism. Interest payments are due under the Revolving Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Revolving Credit Facility.

Our Revolving Credit Facility allows us to fix the interest rate of borrowings under it for all or a portion of the principal balance for a period up to three months; however our borrowings are generally withdrawn with interest rates fixed for one month. Thereafter, to the extent we do not repay the principle, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or prime rate as applicable. As a result, changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt at December 31, 2013 would cost us approximately \$750,000 in additional annual interest expense.

Item 8. Financial Statements and Supplementary Data

The financial statements and supplementary financial information required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods

specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

As of December 31, 2013, our management, including our Chief Executive Officer and Chief Financial Officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our Chief Executive Officer and Chief Financial Officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of December 31, 2013.

No change in our company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2013, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The management of Northern Oil and Gas, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (1992).

Based on our evaluation under the framework in Internal Control-Integrated Framework, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our Company's internal control over financial reporting as of December 31, 2013, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Northern Oil and Gas, Inc.

We have audited the internal control over financial reporting of Northern Oil and Gas, Inc. (the “Company”) as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the financial statements as of and for the year ended December 31, 2013 of the Company and our report dated March 3, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota

March 3, 2014

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Item 9B. Other Information

None.

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PART III

Certain information required by this Part III is incorporated by reference from our definitive Proxy Statement for the Annual Meeting of Shareholders to be held in 2014 (the “Proxy Statement”), which we intend to file with the SEC pursuant to Regulation 14A within 120 days after December 31, 2013. Except for those portions specifically incorporated into this Annual Report on Form 10-K by reference to the Proxy Statement, no other portions of the Proxy Statement are deemed to be filed as part of this Annual Report on Form 10-K.

Item 10. Directors, Executive Officers and Corporate Governance

The information included in “Part I – Executive Officers of the Registrant” of this report is incorporated herein by reference.

The information appearing under the headings “Proposal 1: Election of Directors,” “Corporate Governance” and “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics that applies to our chief executive officer, chief financial officer and persons performing similar functions. A copy is available on our website at www.northernoil.com. We intend to post on our website any amendments to, or waivers from, our Code of Business Conduct and Ethics pursuant to the rules of the SEC and NYSE MKT.

Item 11. Executive Compensation

The information appearing under the headings “Executive Compensation” and “Compensation Committee Report,” and the information regarding compensation committee interlocks and insider participation under the heading “Corporate Governance,” in the Proxy Statement is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information with respect to our common shares issuable under our equity compensation plans as of December 31, 2013:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
2006 Incentive Stock Option Plan	241,872	\$ 5.18	–
2013 Equity Incentive Plan	–	–	2,019,048
Equity compensation plans not approved by security holders	–	–	–
Total	241,872	\$ 5.18	2,019,048

The information appearing under the heading “Security Ownership of Certain Beneficial Owners and Management” in the Proxy Statement is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information appearing under the headings “Certain Relationships and Related Transactions” and “Corporate Governance” in the Proxy Statement is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information appearing under the heading “Proposal 2: Ratification of Appointment of Independent Registered Public Accountants” in the Proxy Statement is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this Report:

1. Financial Statements
See Index to Financial Statements on page F-1.
2. Financial Statement Schedules
Supplemental Oil and Gas Information

All other schedules are omitted because they are either not applicable or required information is shown in the financial statements or notes thereto.

(b) Exhibits:

Unless otherwise indicated, all documents incorporated by reference into this report are filed with the SEC pursuant to the Securities and Exchange Act of 1934, as amended, under file number 001-33999.

Exhibit No.	Description	Reference
3.1	Articles of Incorporation of Northern Oil and Gas, Inc. dated June 28, 2010	Incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed with the SEC on July 2, 2010
3.2	By-Laws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.2 to the Registrant’s Current Report on Form 8-K filed with the SEC on July 2, 2010
4.1	Specimen Stock Certificate of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 10-K filed with the SEC on February 29, 2012
4.2	Indenture, dated May 18, 2012, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.000% Senior Note due 2020)	Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed with the SEC on March 18, 2012
10.1	Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and *Michael L. Reger, dated January 30, 2009	Incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed with the SEC on February 2, 2009 (File No. 001-33999)
10.2	Amendment No. 1 to Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and Michael L. Reger, *dated January 14, 2011	Incorporated by reference to Exhibit 10.3 to the Registrant’s Current Report on Form 10-K filed with the SEC on March 4, 2011 (File No. 001-33999)
10.3	*Separation Agreement and Release, dated October 1, 2012, between Northern Oil and Gas,	Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed

	Inc. and Ryan R. Gilbertson	with the SEC on October 1, 2012
	Consulting Agreement, dated October 1, 2012, between Northern Oil and Gas, Inc. and Ryan R. *Gilbertson	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2012
10.4		

10.5	Employment Agreement by and between Northern Oil and Gas, Inc. and Thomas W. Stoelk, dated *November 8, 2011	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 9, 2011
10.6	Employment Agreement by and between Northern Oil and Gas, Inc. and Brandon Elliott, dated *January 1, 2013	Incorporated by reference to Exhibit 10.10 to the Registrant's Current Report on Form 10-K filed with the SEC on March 1, 2013
10.7	Employment Agreement by and between Northern Oil and Gas, Inc. and Erik J. Romslo, dated October *10, 2011	Incorporated by reference to Exhibit 10.11 to the Registrant's Current Report on Form 10-K filed with the SEC on March 1, 2013
10.8	Northern Oil and Gas, Inc. Amended and Restated *2009 Equity Incentive Plan	Incorporated by reference to Appendix A to the Registrant's Definitive Proxy Statement filed with the SEC on May 2, 2011
10.9	Northern Oil and Gas, Inc. Amended and Restated *2009 Equity Incentive Plan Amendment No.1	Incorporated by reference to Exhibit 10.14 to the Registrant's Current Report on Form 10-K filed with the SEC on March 1, 2013
10.10	Form of Restricted Stock Agreement under the Northern Oil and Gas, Inc. 2009 Equity Incentive *Plan (for grants prior to June 8, 2011)	Incorporated by reference to Exhibit 10.19 to the Registrant's Current Report on Form 10-K filed with the SEC on March 8, 2010
10.11	Form of Restricted Stock Agreement under the Northern Oil and Gas, Inc. Amended and Restated 2009 Equity Incentive Plan (for "single trigger" *grants after June 8, 2011)	Incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 10-K filed with the SEC on February 29, 2012
10.12	Form of Restricted Stock Agreement under the Northern Oil and Gas, Inc. Amended and Restated 2009 Equity Incentive Plan (for "double trigger" *grants after December 20, 2012)	Incorporated by reference to Exhibit 10.17 to the Registrant's Current Report on Form 10-K filed with the SEC on March 1, 2013
10.13	* Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Appendix A to the Registrant's Definitive Proxy Statement filed with the SEC on April 19, 2013
10.14	Northern Oil and Gas, Inc. Form of Restricted Stock Award Agreement (Single Trigger) under the *Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2013
10.15	Northern Oil and Gas, Inc. Form of Restricted Stock Award Agreement (Double Trigger) under *the Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2013
10.16	Third Amended and Restated Credit Agreement, dated as of February 28, 2012, among Northern Oil and Gas, Inc., as Borrower, Royal Bank of Canada, as Administrative Agent, SunTrust Bank, as Syndication Agent, Bank of Montreal, KeyBank, N.A. and U.S. Bank N.A., as Co-Documentation Agents, and the Lenders party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on March 2, 2012
10.17	First Amendment to Third Amended and Restated Credit Agreement, dated June 29, 2012, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders Party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2012
10.18	Second Amendment to Third Amended and Restated Credit Agreement, dated September 28,	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with

2012, by and among Northern Oil and Gas, Inc., the SEC on October 2, 2012
Royal Bank of Canada, and the Lenders Party
thereto

10.19	Third Amendment to Third Amended and Restated Credit Agreement, dated March 28, 2013, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders Party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 1, 2013
10.20	Fourth Amendment to Third Amended and Restated Credit Agreement and Second Amendment to Third Amended and Restated Guaranty and Collateral Agreement, dated September 30, 2013, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders Party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2013
12	Calculation of Ratio of Earnings to Fixed Charges	Filed herewith
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP	Filed herewith
23.2	Consent of Ryder Scott Company, LP	Filed herewith
24.1	Powers of Attorney	Filed herewith (included on signature page)
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Report of Ryder Scott Company, LP	Filed herewith
101.INS	XBRL Instance Document(1)	Filed Electronically
101.SCH	XBRL Taxonomy Extension Schema Document(1)	Filed Electronically
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document(1)	Filed Electronically
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document(1)	Filed Electronically
101.LAB	XBRL Taxonomy Extension Label Linkbase Document(1)	Filed Electronically
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document(1)	Filed Electronically

* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report.

(1)The XBRL related information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability of that

section and shall not be incorporated by reference into any filing or other document pursuant to the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such filing or document.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date: March 3, 2014

By: /s/ Michael L. Reger
Michael L. Reger
Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints, Michael L. Reger and Thomas W. Stoelk, or either of them, his/her true and lawful attorney-in-fact and agent, acting alone, with full power of substitution and resubstitution, for him/her and in his/her name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Commission, granting unto said attorney-in-fact and agent, each acting alone, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all said attorney-in-fact and agent, acting alone, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ Michael L. Reger Michael L. Reger	Chief Executive Officer, Chairman and Director	March 3, 2014
/s/ Thomas W. Stoelk Thomas W. Stoelk	Chief Financial Officer, Principal Financial Officer, Principal Accounting Officer	March 3, 2014
/s/ Richard Weber Richard Weber	Director	March 3, 2014
/s/ Jack King Jack King	Director	March 3, 2014
/s/ Robert Grabb Robert Grabb	Director	March 3, 2014
/s/ Lisa Bromiley Lisa Bromiley	Director	March 3, 2014

/s/ Delos Cy Jamison
Delos Cy Jamison

Director

March 3, 2014

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NORTHERN OIL AND GAS, INC.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Northern Oil and Gas, Inc.:

We have audited the accompanying balance sheets of Northern Oil and Gas, Inc. (the “Company”) as of December 31, 2013 and 2012, and the related statements of comprehensive income, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Northern Oil and Gas, Inc. as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 3, 2014 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 3, 2014

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31,	
	2013	2012
CURRENT ASSETS		
Cash and Cash Equivalents	\$5,687,166	\$13,387,998
Trade Receivables	86,816,981	70,219,669
Advances to Operators	618,786	3,109,591
Prepaid and Other Expenses	770,740	1,707,089
Derivative Instruments	62,890	4,095,197
Deferred Tax Asset	10,431,000	1,695,000
Total Current Assets	104,387,563	94,214,544
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	1,611,073,747	1,159,191,601
Unproved	70,148,348	82,926,384
Other Property and Equipment	1,701,366	3,158,224
Total Property and Equipment	1,682,923,461	1,245,276,209
Less - Accumulated Depreciation and Depletion	(285,616,752)	(162,031,493)
Total Property and Equipment, Net	1,397,306,709	1,083,244,716
DERIVATIVE INSTRUMENTS	1,745,405	1,763,008
DEBT ISSUANCE COSTS	16,160,283	11,713,030
TOTAL ASSETS	\$1,519,599,960	\$1,190,935,298
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	\$168,936,785	\$95,822,162
Accrued Expenses	2,645,178	2,454,085
Accrued Interest	3,386,409	2,180,416
Derivative Instruments	19,119,646	-
Total Current Liabilities	194,088,018	100,456,663
LONG-TERM LIABILITIES		
Revolving Credit Facility	75,000,000	124,000,000
8% Senior Notes Due 2020, Net of Accumulated Amortization of \$960,177 and \$0 at December 31, 2013 and 2012, respectively	509,539,823	300,000,000
Derivative Instruments	637,208	2,547,745
Other Noncurrent Liabilities	3,832,550	1,570,630
Deferred Tax Liability	116,674,000	76,175,000
Total Long-Term Liabilities	705,683,581	504,293,375
TOTAL LIABILITIES	899,771,599	604,750,038
COMMITMENTS AND CONTINGENCIES (NOTE 8)		

STOCKHOLDERS' EQUITY

Preferred Stock, Par Value \$.001; 5,000,000 Authorized, No Shares Outstanding	-	-
Common Stock, Par Value \$.001; 95,000,000 Authorized (12/31/2013 – 61,858,199 Shares Outstanding and 12/31/2012 – 63,532,622 Shares Outstanding)	61,858	63,532
Additional Paid-In Capital	446,044,159	465,466,420
Retained Earnings	173,722,344	120,655,308
Total Stockholders' Equity	619,828,361	586,185,260

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	\$ 1,519,599,960	\$ 1,190,935,298
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The accompanying notes are an integral part of these financial statements.

NORTHERN OIL AND GAS, INC.
STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

	Year Ended December 31,		
	2013	2012	2011
REVENUES			
Oil and Gas Sales	\$369,187,120	\$296,637,857	\$159,439,508
Loss on Settled Derivatives	(12,198,633)	(391,420)	(13,407,878)
(Losses) Gains on the Mark-to-Market of Derivative Instruments	(21,259,018)	15,147,122	3,072,229
Other Revenue	44,402	179,331	285,234
Total Revenues	335,773,871	311,572,890	149,389,093
OPERATING EXPENSES			
Production Expenses	41,859,135	32,382,310	13,043,633
Production Taxes	34,958,975	28,485,594	14,300,720
General and Administrative Expense	16,575,440	22,645,315	13,624,892
Depletion, Depreciation, Amortization and Accretion	124,383,374	98,923,240	41,169,618
Total Expenses	217,776,924	182,436,459	82,138,863
INCOME FROM OPERATIONS	117,996,947	129,136,431	67,250,230
OTHER INCOME (EXPENSE)			
Other Income (Expense)	(453,241)	24,874	782,544
Interest Expense, Net of Capitalization	(32,709,056)	(13,874,909)	(585,982)
Total Other Income (Expense)	(33,162,297)	(13,850,035)	196,562
INCOME BEFORE INCOME TAXES	84,834,650	115,286,396	67,446,792
INCOME TAX PROVISION	31,767,614	43,001,772	26,835,300
NET INCOME	\$53,067,036	\$72,284,624	\$40,611,492
OTHER COMPREHENSIVE INCOME, NET OF TAX			
Unrealized Gains on Marketable Securities (Net of Tax of \$109,000 for the year ended December 31, 2011)	-	-	173,846
Reclassification of Derivative Instruments Included in Income (Net of Tax of \$39,000 and \$448,000 for the years ended December 31, 2012 and 2011, respectively)	-	62,309	709,776
Total Other Comprehensive Income	-	62,309	883,622
COMPREHENSIVE INCOME	\$53,067,036	\$72,346,933	\$41,495,114
Net Income Per Common Share – Basic	\$0.85	\$1.16	\$0.66
Net Income Per Common Share – Diluted	\$0.85	\$1.15	\$0.65
Weighted Average Shares Outstanding – Basic	62,364,957	62,485,836	61,789,289
Weighted Average Shares Outstanding – Diluted	62,747,298	62,869,079	62,195,340

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

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NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

	Year Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	\$53,067,036	\$72,284,624	\$40,611,492
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depletion, Depreciation, Amortization and Accretion	124,383,374	98,923,240	41,169,618
Amortization of Debt Issuance Costs	2,625,240	1,527,194	430,760
Amortization of Senior Unsecured Notes Premium	(960,177)	-	-
Loss on the Sale of Other Property & Equipment	473,915	(23,611)	-
Deferred Income Taxes	31,763,000	42,984,000	26,833,000
Net (Gain) Loss on Sale of Available for Sale Securities	-	-	(215,092)
Loss (Gain) on the Mark-to-Market of Derivative Instruments	21,259,018	(15,147,122)	(3,072,229)
Amortization of Deferred Rent	(19,541)	(33,230)	(19,795)
Share - Based Compensation Expense	4,798,977	12,381,757	6,164,324
Changes in Working Capital and Other Items:			
Trade Receivables	(16,597,312)	(18,800,839)	(29,385,183)
Prepaid Expenses and Other	28,350	4,792	17,781
Accounts Payable	2,006,516	(63,025)	2,486,667
Accrued Interest	(245,082)	2,081,618	98,798
Accrued Expenses	191,093	2,407,216	29,385
Net Cash Provided By Operating Activities	222,774,407	198,526,614	85,149,526
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchases of Oil and Natural Gas Properties and Development Capital Expenditures	(360,058,127)	(531,954,977)	(341,363,955)
Advances to Operators	-	-	(4,304,824)
Proceeds from Sale of Oil and Natural Gas Properties	908,000	-	5,027,162
Proceeds from Sale of Available for Sale Securities	-	-	58,606,328
Proceeds from Sale of Other Property and Equipment	1,003,025	39,000	-
Purchase of Available for Sale Securities	-	-	(18,381,690)
Purchases of Other Property and Equipment	(389,317)	(256,445)	(450,822)
Net Cash Used For Investing Activities	(358,536,419)	(532,172,422)	(300,867,801)
CASH FLOWS FROM FINANCING ACTIVITIES			
Advances on Revolving Credit Facility	133,000,000	475,600,000	79,900,000
Repayments on Revolving Credit Facility	(182,000,000)	(421,500,000)	(10,000,000)
Issuance of Senior Unsecured Notes	210,500,000	300,000,000	-
Debt Issuance Costs Paid	(7,072,493)	(11,854,023)	(449,837)
Repurchases of Common Stock	(26,366,327)	(1,546,148)	(1,081,132)
Proceeds from Exercise of Warrants	-	-	1,500,000
Proceeds from Exercise of Stock Options	-	54,390	18,130
Net Cash Provided by Financing Activities	128,061,180	340,754,219	69,887,161
	(7,700,832)	7,108,411	(145,831,114)

NET INCREASE (DECREASE) IN CASH AND CASH
EQUIVALENTS

CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	13,387,998	6,279,587	152,110,701
CASH AND CASH EQUIVALENTS – END OF PERIOD	\$5,687,166	\$13,387,998	\$6,279,587
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Period for Interest	\$35,761,112	\$15,579,140	\$286,710
Cash Paid During the Period for Income Taxes	\$13,614	\$8,772	\$-
Non-Cash Financing and Investing Activities:			
Oil and Natural Gas Properties Included in Accounts Payable	\$162,884,221	\$91,776,113	\$106,024,212
Capitalized Asset Retirement Obligations	\$1,852,580	\$539,727	\$401,241
Non-Cash Compensation Capitalized in Oil and Gas Properties	\$2,143,415	\$6,378,273	\$13,114,137

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

NORTHERN OIL AND GAS, INC.
 STATEMENTS OF STOCKHOLDERS' EQUITY
 FOR THE YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

	Common Stock		Additional	Accumulated Other Comprehensive	Retained	Total
	Shares	Amount	Paid-In Capital	Income (Loss)	Earnings	Stockholders' Equity
Balance - December 31, 2010	62,129,424	\$62,129	\$428,484,092	\$ (945,931)	\$7,759,192	\$435,359,482
Net Issuance of Common Stock	1,200,997	1,201	4,770,710	-	-	4,771,911
Share Based Compensation	-	-	14,943,548	-	-	14,943,548
Net Change in Cash Flow Hedge Derivatives	-	-	-	709,776	-	709,776
Net Change in Unrealized Gain(Loss) on Short-term Investments	-	-	-	173,846	-	173,846
Net Income	-	-	-	-	40,611,492	40,611,492
Balance - December 31, 2011	63,330,421	\$63,330	\$448,198,350	\$ (62,309)	\$48,370,684	\$496,570,055
Net Issuance of Common Stock	202,201	202	(1,491,960)	-	-	(1,491,758)
Share Based Compensation	-	-	18,760,030	-	-	18,760,030
Net Change in Cash Flow Hedge Derivatives	-	-	-	62,309	-	62,309
Net Income	-	-	-	-	72,284,624	72,284,624
Balance - December 31, 2012	63,532,622	\$63,532	\$465,466,420	\$ -	\$120,655,308	\$586,185,260
Net Issuance of Common Stock	361,960	362	(252,993)	-	-	(252,631)
	-	-	6,942,020	-	-	6,942,020

Share Based
Compensation

Repurchases of Common Stock	(2,036,383)	(2,036)	(26,111,288)	-	-	(26,113,324)
Net Income	-	-	-	-	53,067,036	53,067,036
Balance - December 31, 2013	61,858,199	\$61,858	\$446,044,159	\$ -	\$173,722,344	\$619,828,361

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

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2013

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the “Company,” “Northern,” “our” and words of similar import), a Minnesota corporation, is an independent energy company engaged in the acquisition, exploration, exploitation, development and production of crude oil and natural gas properties. The Company’s common stock trades on the NYSE MKT market under the symbol “NOG”.

Northern’s principal business is crude oil and natural gas exploration, development, and production with operations in North Dakota and Montana that primarily target the Bakken and Three Forks formations in the Williston Basin of the United States. The Company acquires leasehold interests that comprise of non-operated working interests in wells and in drilling projects within its area of operations. As of December 31, 2013, approximately 58% of Northern’s 187,044 total net acres were developed. As of December 31, 2012, approximately 50% of Northern’s 179,131 total net acres were developed.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). In connection with preparing the financial statements for the year ended December 31, 2013, the Company has evaluated subsequent events for potential recognition and disclosure through the date of this filing and determined that there were no subsequent events which required recognition or disclosure in the financial statements through the date of this filing.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to proved crude oil and natural gas reserve volumes, future development costs, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, and deferred income taxes. Actual results may differ from those estimates.

Cash and Cash Equivalents

Northern considers highly liquid investments with insignificant interest rate risk and original maturities to the Company of three months or less to be cash equivalents. Cash equivalents consist primarily of interest-bearing bank accounts and money market funds. The Company’s cash positions represent assets held in checking and money market accounts. These assets are generally available on a daily or weekly basis and are highly liquid in nature. Due to the balances being greater than \$250,000, the Company does not have FDIC coverage on the entire amount of bank deposits. The Company believes this risk is minimal. In addition, the Company is subject to Security Investor Protection Corporation (“SIPC”) protection on a vast majority of its financial assets.

Accounts Receivable

Accounts receivable are carried on a gross basis, with no discounting. The Company regularly reviews all aged accounts receivable for collectability and establishes an allowance as necessary for individual customer balances.

At December 31, 2013 and 2012, the allowance for doubtful accounts was \$1,050,000 and \$0, respectively. The amount charged to operations for doubtful accounts was \$1,050,000, \$0, and \$0 for the years ended December 31, 2013, 2012 and 2011, respectively.

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Advances to Operators

The Company participates in the drilling of crude oil and natural gas wells with other working interest partners. Due to the capital intensive nature of crude oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to seven years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was \$325,859, \$409,888, and \$298,137 for the years ended December 31, 2013, 2012 and 2011, respectively.

Full Cost Method

Northern follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are initially capitalized into a single cost center (“full cost pool”). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to the production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Capitalized costs are summarized as follows for the years ended December 31, 2013, 2012 and 2011, respectively:

	Year Ended December 31,		
	2013	2012	2011
Capitalized Certain Payroll and Other Internal Costs	\$3,295,427	\$8,477,678	\$16,952,995
Capitalized Interest Costs	5,976,981	5,929,473	405,984
Total	\$9,272,408	\$14,407,151	\$17,358,979

As of December 31, 2013, the Company held leasehold interests in the Williston Basin on acreage located in North Dakota and Montana targeting the Bakken and Three Forks formations.

Proceeds from property sales will generally be credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool. In the years ended December 31, 2013, 2012 and 2011, the Company sold acreage and interests in producing properties for \$0, \$908,000, and \$5.0 million, respectively. The proceeds for these sales were applied to reduce the capitalized costs of crude oil and natural gas properties.

Capitalized costs associated with impaired properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum

engineers. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the years ended December 31, 2013, 2012 and 2011, the Company transferred into the full cost pool costs related to expired leases of \$14.1 million, \$7.1 million, and \$9.0 million, respectively.

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Capitalized costs of crude oil and natural gas properties (net of related deferred income taxes) may not exceed an amount equal to the present value, discounted at 10% per annum, of the estimated future net cash flows from proved crude oil and natural gas reserves plus the cost of unproved properties (adjusted for related income tax effects). Should capitalized costs exceed this ceiling, impairment is recognized. The present value of estimated future net cash flows is computed by applying the 12-month average price of crude oil and natural gas to estimated future production of proved crude oil and natural gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. Such present value of proved reserves' future net cash flows excludes future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet. Should this comparison indicate an excess carrying value, the excess is charged to earnings as an impairment expense. During the three year period ended December 31, 2013, the Company has not realized any impairment of its properties.

Asset Retirement Obligations

Asset retirement obligation is included in other noncurrent liabilities and relates to future costs associated with the plugging and abandonment of crude oil and natural gas wells, removal of equipment and facilities from leased acreage and returning the land to its original condition. Estimates are based on estimated remaining lives of those wells based on reserve estimates, external estimates to plug and abandon the wells in the future, inflation, credit adjusted discount rates and federal and state regulatory requirements. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Debt Issuance Costs

Deferred financing costs include origination, legal and other fees to issue debt in connection with the Company's credit facility and senior unsecured notes. These debt issuance costs are being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method (see Note 4).

The amortization of debt issuance costs for the years ended December 31, 2013, 2012 and 2011 was \$2,625,240, \$1,527,194 and \$430,760, respectively.

Bond Premium on Senior Notes

At December 31, 2013, the Company had recorded a bond premium of \$10.5 million in connection with the "8% Senior Notes Due 2020" (see Note 4). This bond premium is being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

The amortization of the bond premium for the years ended December 31, 2013, 2012 and 2011 was \$960,177, \$0 and \$0, respectively.

Revenue Recognition

The Company recognizes crude oil and natural gas revenues from its interests in producing wells when production is delivered to, and title has transferred to, the purchaser and to the extent the selling price is reasonably determinable. The Company uses the sales method of accounting for natural gas balancing of natural gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of December 31, 2013, 2012 and 2011, the Company's natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

Concentrations of Market and Credit Risk

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company's receivables include amounts due from purchasers of its crude oil and natural gas production. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations over the long-term. Trade receivables are generally not collateralized.

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The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its customers is generally high. In the normal course of business, letters of credit or parent guarantees may be required for counterparties which management perceives to have a higher credit risk.

Stock-Based Compensation

The Company records expense associated with the fair value of stock-based compensation. For fully vested stock and restricted stock grants the Company calculates the stock based compensation expense based upon estimated fair value on the date of grant. For stock options, the Company uses the Black-Scholes option valuation model to calculate stock based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate.

Stock Issuance

The Company records the stock-based compensation awards issued to non-employees and other external entities for goods and services at either the fair market value of the goods received or services rendered or the instruments issued in exchange for such services, whichever is more readily determinable.

Income Taxes

Deferred income tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is “more likely than not” that some component or all of the benefits of deferred tax assets will not be realized. No valuation allowance has been recorded as of December 31, 2013 and 2012.

Net Income Per Common Share

Basic earnings per share (“EPS”) are computed by dividing net income (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include stock options and warrants and restricted stock. The number of potential common shares outstanding relating to stock options and warrants and restricted stock is computed using the treasury stock method.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the years ended December 31, 2013, 2012 and 2011 are as follows:

	Year Ended December 31,		
	2013	2012	2011
Weighted average common shares outstanding – basic	62,364,957	62,485,836	61,789,289
Plus: Potentially dilutive common shares			
Stock options, warrants, and restricted stock	382,341	383,243	406,051

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Weighted average common shares outstanding – diluted	62,747,298	62,869,079	62,195,340
Restricted stock excluded from EPS due to the anti-dilutive effect	7,330	18,348	29,876

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As of December 31, 2013, 2012 and 2011, potentially dilutive shares from stock options were 241,872, 251,963, and 262,463, respectively. These options are all exercisable at December 31, 2013, 2012 and 2011, at an exercise price of \$5.18.

The Company also has potentially dilutive shares from restricted stock grants outstanding of 592,565, 777,437, and 1,216,992, at December 31, 2013, 2012, and 2011, respectively.

In January 2011, 300,000 warrants that were issued in conjunction with the February 2009 revolving credit facility were exercised at a price of \$5.00 per share.

Derivative Instruments and Price Risk Management

The Company uses derivative instruments to manage market risks resulting from fluctuations in the prices of crude oil. The Company enters into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company has, and may continue to use exchange traded futures contracts and option contracts to hedge the delivery price of crude oil at a future date.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and in addition, the Company has elected not to designate any subsequent derivative contracts as accounting hedges. As such, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses are recorded to gain (loss) on settled derivatives and mark-to-market gains or losses are recorded to (loss) gain on the mark-to-market of derivative instruments on the statements of income and comprehensive income rather than as a component of accumulated other comprehensive income (loss) or other income (expense). See Note 14 for a description of the derivative contracts which the Company has entered into.

Prior to November 1, 2009, the Company, at the inception of a derivative contract, designated the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documented the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company historically measured hedge effectiveness on a quarterly basis and hedge accounting would be discontinued prospectively if it determined that the derivative was no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses deferred in accumulated other comprehensive income (loss) related to cash flow hedge derivatives that become ineffective remain unchanged until the related production was delivered. If the Company determined that it was probable that a hedged forecasted transaction would not occur, deferred gains or losses on the derivative were recognized in earnings immediately.

Derivatives, historically, were recorded on the balance sheet at fair value and changes in the fair value of derivatives were recorded each period in current earnings or other comprehensive income (loss), depending on whether a derivative was designated as part of a hedge transaction and, if it was, depending on the type of hedge transaction. The Company's derivatives historically consisted primarily of cash flow hedge transactions in which the Company was hedging the variability of cash flows related to a forecasted transaction. Period to period changes in the fair value of derivative instruments designated as cash flow hedges were reported in accumulated other comprehensive income (loss) and reclassified to earnings in the periods in which the hedged item impacts earnings. The ineffective portion of the cash flow hedges were reflected in current period earnings as gain or loss from derivatives. Gains and

losses on derivative instruments that did not qualify for hedge accounting were included in income or loss from derivatives in the period in which they occur. The resulting cash flows from derivatives were reported as cash flows from operating activities.

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Impairment

Long-lived assets to be held and used are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Crude oil and natural gas properties accounted for using the full cost method of accounting (which the Company uses) are excluded from this requirement but continue to be subject to the full cost method's impairment rules. There was no impairment recorded at December 31, 2013, 2012, and 2011.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

Recently Adopted

Balance Sheet Offsetting — In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. These disclosure requirements do not affect the presentation of amounts in the balance sheets, and are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual reporting periods. The implementation of this disclosure guidance did not have a material impact on the Company's financial statements.

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The value of the Company's crude oil and natural gas properties consists of all acreage acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying statements of income and comprehensive income from the closing date of the acquisition. Purchase prices are allocated to acquired assets based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of equity securities. Purchases of properties and development capital expenditures that were in accounts payable and not yet paid in cash at December 31, 2013 and 2012 were approximately \$163 million and \$92 million, respectively.

2013 Acquisitions

During 2013, the Company acquired approximately 20,900 net acres, for an average cost of approximately \$1,279 per net acre, in its key prospect areas in the form of effective leases. During the same period, the Company separately acquired working interests in 70 gross (7.0 net) wells in undrilled locations in which it does not hold the underlying leasehold interests, for a total cost of approximately \$9.0 million.

2012 Acquisitions

During 2012, the Company acquired approximately 17,590 net acres, for an average cost of approximately \$1,788 per net acre, in its key prospect areas in the form of effective leases, and earned an additional 6,450 net acres through farm-in arrangements.

2011 Acquisitions

During 2011, the Company acquired approximately 43,239 net acres, for an average cost of approximately \$1,832 per net acre, in its key prospect areas in the form of effective leases.

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Divestitures

In April 2011, the Company sold its interest in the Anvil project for \$5.0 million. As of the date of sale, the Company's cost basis in the Anvil project was \$1.8 million. The Company sold its interest in the project along with Slawson Exploration Company, Inc. ("Slawson"), who also desired to sell its entire interest in the project. Slawson had drilled and completed one well in the project area prior to the divestiture – the Mayhem #1-19H well – and the Company retained its interest in that wellbore in connection with the divestiture. The proceeds from the sale were applied to reduce the capitalized costs of crude oil and natural gas properties. In the fourth quarter of 2012, the Company sold its interest in certain North Dakota and Montana properties covering 835 net acres for \$0.9 million in consideration.

From time-to-time the Company may also trade leasehold interests with operators to balance working interests in spacing units to facilitate and encourage a more expedited development of the Company's acreage.

Unproved Properties

Unproved properties not being amortized comprise approximately 60,600 net acres and 63,000 net acres of undeveloped leasehold interests at December 31, 2013 and 2012, respectively. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company 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 its reserves.

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2013 by year incurred.

	Year Ended December 31,			
	2013	2012	2011	Prior Years
Property Acquisition	\$19,608,861	\$18,629,120	\$33,133,410	\$30,971,709
Development	-	193,017	-	-
Total	\$19,608,861	\$18,822,137	\$33,133,410	\$30,971,709

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.

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

NOTE 4 REVOLVING CREDIT FACILITY AND LONG TERM DEBT

Revolving Credit Facility

In February 2012, the Company entered into an amended and restated credit agreement providing for a revolving credit facility (the “Revolving Credit Facility”), which replaced its previous revolving credit facility with a syndicated facility. The Revolving Credit Facility, which is secured by substantially all of the Company’s assets, provides for a commitment equal to the lesser of the facility amount or the borrowing base. At December 31, 2013, the facility amount was \$750 million, the borrowing base was \$450 million and there was a \$75 million outstanding balance, leaving \$375 million of borrowing capacity available under the facility. Under the terms of the Revolving Credit Facility, the Company may issue an unlimited amount of permitted additional indebtedness, as defined, provided that the borrowing base will be reduced by 25% of the stated amount of any such permitted additional indebtedness. The \$500 million in Notes described below is “permitted additional indebtedness” as defined in the Revolving Credit Facility.

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The Revolving Credit Facility matures on September 30, 2018 and provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. Borrowings under the Revolving Credit Facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.5% to 1.5% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined) plus a spread ranging from 1.5% to 2.5%. The applicable spread at any time is dependent upon the amount of borrowings relative to the borrowing base at such time. The Company may elect, from time to time, to convert all or any part of its LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. A commitment fee is paid on the undrawn balance based on an annual rate of either 0.375% or 0.50%. At December 31, 2013, the commitment fee was 0.375% and the interest rate margin was 1.5% on LIBOR loans and 0.5% on base rate loans.

The Revolving Credit Facility contains negative covenants that limit the Company's ability, among other things, to pay any cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of its business or operations, merge, consolidate, or make investments. In addition, the Company is required to maintain a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0.

All of the Company's obligations under the Revolving Credit Facility are secured by a first priority security interest in any and all assets of the Company.

8.000% Senior Notes Due 2020

On May 18, 2012, the Company issued at par value \$300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Original Notes"). On May 13, 2013, the Company issued at a price of 105.25% an additional \$200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Follow-on Notes" and, together with the Original Notes, the "Notes"). Interest is payable on the Notes semi-annually in arrears on each of June 1 and December 1. The Company currently does not have any subsidiaries and, as a result, the Notes are not currently guaranteed. Any subsidiaries the Company forms in the future may be required to unconditionally guarantee, jointly and severally, payment obligation under the Notes on a senior unsecured basis. The issuance of the Original Notes resulted in net proceeds to the Company of approximately \$291.2 million and the issuance of the Follow-on Notes resulted in net proceeds to the Company of approximately \$200.1 million, which are in use to fund the Company's exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

At any time prior to June 1, 2015, the Company may redeem up to 35% of the Notes at a redemption price of 108% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings, so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to June 1, 2016, the Company may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after June 1, 2016, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104% for the twelve-month period beginning on June 1, 2016, 102% for the twelve-month period beginning June 1, 2017 and 100% beginning on June 1, 2018, plus accrued and unpaid interest to the redemption date.

The Notes are governed by an Indenture (the "Indenture"), dated as of May 18, 2012, by and among the Company and Wilmington Trust, National Association, as trustee (the "Trustee").

The Indenture restricts the Company's ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or, repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries (if any) will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;

- failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and certain of its subsidiaries, if any, in the aggregate principal amount of \$25 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary;
- failure by the Company or any significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary to pay certain final judgments aggregating in excess of \$25 million within 60 days; and
- any guarantee of the Notes by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

NOTE 5 COMMON AND PREFERRED STOCK

The Company's Articles of Incorporation authorize the issuance of up to 100,000,000 shares. The shares are classified in two classes, consisting of 95,000,000 shares of common stock, par value \$.001 per share, and 5,000,000 shares of preferred stock, par value \$.001 per share. The board of directors is authorized to establish one or more series of preferred stock, setting forth the designation of each such series, and fixing the relative rights and preferences of each such series. The Company has neither designated nor issued any shares of preferred stock.

Common Stock

The following is a schedule of changes in the number of shares of common stock since the beginning of 2011:

	Year Ended December 31,		
	2013	2012	2011
Beginning Balance	63,532,622	63,330,421	62,129,424
Stock Based Compensation	57,371	53,140	161,628
Stock Options Exercised	10,091	10,500	3,500
Restricted Stock Grants (Note 7)	353,596	837,239	786,263
Warrants Exercised	-	-	300,000
Stock Repurchase	(2,036,383)	-	-
Other Surrenders	(59,098)	(698,678)	(50,394)
Ending Balance	61,858,199	63,532,622	63,330,421

2013 Activity

In 2013, the Company's Chief Executive Officer received shares of common stock as compensation in lieu of any cash base salary. In 2013, the Company issued 57,371 shares valued at approximately \$825,000 to the Chief Executive Officer as compensation in lieu of any cash base salary.

In 2013, 16,585 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately \$253,000, which was based on the market price on the date the shares were surrendered.

In 2013, 39,049 shares of restricted common stock were surrendered by employees who terminated employment with the Company.

In 2013, a director of the Company exercised an aggregate of 10,091 stock options, which were granted in 2007. Of those stock options, 3,464 shares were surrendered to cover the aggregate exercise price of approximately \$52,000, based on the market price on the date the shares were surrendered.

2012 Activity

In 2012, a director of the Company exercised an aggregate of 10,500 stock options granted in 2007.

In 2012, the Company issued 53,140 shares of common stock in aggregate to executives and employees of the Company as compensation for their services. The shares were fully vested on the date of the grant. The fair value of the stock issued was approximately \$1.3 million. The value of the stock was between \$19.34 and \$24.89 per share, the market value of the shares of common stock on the date the stock was issued. The Company expensed approximately \$0.5 million in share-based compensation related to these fully vested shares in the year ended December 31, 2012. The remainder of fair value was capitalized into the full cost pool.

In 2012, 70,128 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately \$1.5 million, which was based on the market price on the date the shares were surrendered.

In 2012, 628,550 shares of common stock were surrendered by certain employees who terminated employment with the Company in connection with their restricted stock awards.

2011 Activity

In January 2011, CIT exercised the 300,000 warrants that were issued as part of a prior revolving credit facility. Total proceeds to the Company from the exercise of these warrants were \$1.5 million.

In 2011, the Company issued 161,628 shares of common stock in aggregate to executives, employees and directors of the Company as compensation for their services. The shares were fully vested on the date of the grant. The fair value of the stock issued was approximately \$4.3 million. The value of the stock was between \$17.81 and \$27.98 per share, the market value of the shares of common stock on the date the stock was issued. The Company expensed approximately \$1.4 million in share-based compensation related to these fully vested shares in the year ended December 31, 2011. The remainder of fair value was capitalized into the full cost pool.

In October 2011, a director of the Company exercised 3,500 stock options granted to him in 2007.

In 2011, 50,394 shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately \$1.1 million, which was based on the market price on the date the shares were surrendered.

Stock Repurchase Program

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to \$150 million of the Company's outstanding common stock. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

During the third quarter of 2013, the Company repurchased 2,036,383 shares of its common stock under the stock repurchase program. These shares are now included in the Company's pool of authorized but unissued shares. This stock had a cost of approximately \$26.1 million. The Company's accounting policy upon the repurchase of shares is to deduct its par value from Common Stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital.

NOTE 6 RELATED PARTY TRANSACTIONS

Carter Stewart, a former director of the Company (until August 2011), owned a 25% interest in Gallatin Resources, LLC (“Gallatin”). Legal counsel for Gallatin informed the Company that Mr. Stewart did not have the power to control Gallatin because each member of Gallatin has the right to vote on matters in proportion to their respective membership interest in the company and company matters are determined by a vote of the holders of a majority of membership interests. Further, Mr. Stewart was neither an officer nor a director of Gallatin. As such, Mr. Stewart did not have the ability to individually control company decisions for Gallatin. In 2011, the Company paid Gallatin a total of approximately \$6,500 related to previously acquired leasehold interests. In 2012, the Company paid Gallatin a total of approximately \$500 related to previously acquired leasehold interests. There were no such payments for the year ended December 31, 2013.

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The Company is a non-operating participant in a number of wells in North Dakota that are operated by Emerald Oil, Inc. (“Emerald”), by virtue of leased acreage held by the Company in drilling units operated by Emerald. As of December 31, 2013, such wells included 14 gross (3.1 net) producing wells, and an additional 3 gross (0.7 net) wells that were drilling or awaiting completion. Based on authorizations for expenditure (or AFEs) provided by Emerald with respect to each of the wells, the total drilling and completion costs for these 17 gross wells was estimated at approximately \$176 million, approximately \$40 million of which is attributable to Northern Oil’s working interest in the wells. James Russell (J.R.) Reger is a director, executive officer and less than 5% shareholder of Emerald, which is a publicly-traded company. J.R. Reger is also the brother of Northern Oil’s Chairman and Chief Executive Officer, Michael Reger. At December 31, 2013, the Company’s accounts receivable and accounts payable balances with Emerald were \$4.6 million and \$23.2 million, respectively. There were no outstanding accounts receivable or accounts payable balances with Emerald at December 31, 2012. The Company recorded total revenues of \$7.8 million, \$0 million, and \$0 million from Emerald for the years ended December 31, 2013, 2012, and 2011, respectively.

All transactions involving related parties were approved or ratified by the Company’s board of directors or Audit Committee.

NOTE 7 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

On April 5, 2013, the board of directors approved the Company’s 2013 Incentive Plan (the “2013 Plan”), which was subsequently approved at the 2013 annual meeting of shareholders. 1,500,000 shares were authorized for grant under the 2013 Plan, plus the number of shares remaining available for future grants under the Company’s predecessor 2009 Equity Incentive Plan on the date the shareholders approved the 2013 Plan. The 2013 Plan is intended to provide a means whereby the Company may be able, by granting equity and other types of awards, to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors of the Company, for the benefit of the Company and its shareholders.

Restricted Stock Awards

During the years ended December 31, 2013, 2012 and 2011, the Company issued 353,596, 837,239 and 786,263, respectively, restricted shares of common stock as compensation to officers, employees, and directors of the Company. Unvested restricted shares vest over various terms with all restricted shares vesting no later than February 2017. As of December 31, 2013, there was approximately \$5.4 million of total unrecognized compensation expense related to unvested restricted stock. This compensation expense will be recognized over the remaining vesting period of the grants. The Company has assumed a zero percent forfeiture rate for restricted stock due to the small number of officers, employees and directors that have received restricted stock awards.

The following table reflects the outstanding restricted stock awards and activity related thereto for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013		Year Ended December 31, 2012		Year Ended December 31, 2011	
	Number of Shares	Weighted- Average Price	Number Of Shares	Weighted- Average Price	Number Of Shares	Weighted- Average Price
Restricted Stock Awards:						
Restricted Shares Outstanding at the Beginning of the Year	777,437	\$ 18.93	1,216,992	\$ 19.87	1,135,622	\$ 13.28

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Shares Granted	353,596	15.33	837,239	19.91	786,263	27.11
Shares Forfeited	(39,049)	16.78	(628,550)	19.08	-	-
Lapse of Restrictions	(499,419)	19.03	(648,244)	21.83	(704,893)	17.32
Restricted Shares Outstanding at the End of the Year	592,565	\$16.84	777,437	\$18.93	1,216,992	\$19.87

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Stock Option Awards

On November 1, 2007, the board of directors granted options to purchase 560,000 shares of the Company's common stock under the Company's 2006 Incentive Stock Option Plan. The Company granted options to purchase 500,000 shares of the Company's common stock to members of the board and options to purchase 60,000 shares of the Company's common stock to one employee pursuant to an employment agreement. These options were granted at a price of \$5.18 per share and the optionees were fully vested on the grant date. As of December 31, 2013, options to purchase a total of 241,872 shares of the Company's common stock remain outstanding but unexercised. The board of directors determined that no future grants will be made pursuant to the 2006 Incentive Stock Option Plan. All future stock compensation will be issued under the 2013 Plan.

The Company used the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. The Company used the simplified method to determine the expected term of the options due to the lack of sufficient historical data. Changes in these assumptions can materially affect the fair value estimate. The total fair value of the options is recognized as compensation over the vesting period. There were no stock options granted by the Company in 2013, 2012 and 2011. All exercises of options during 2013, 2012 and 2011 related to 2007 grants.

Changes in stock options for the years ended December 31, 2013, 2012, and 2011 were as follows:

	Number of Shares	Weighted Average Exercise Price	Remaining Contractual Term (in Years)	Intrinsic Value
2013:				
Beginning Balance	251,963	\$-	-	\$-
Granted	-	-	-	-
Exercised	(10,091)	5.18	-	-
Forfeited	-	-	-	-
Outstanding at December 31	241,872	5.18	3.8	2,392,000
Exercisable	241,872	5.18	3.8	2,392,000
Ending Vested	241,872	5.18	3.8	2,392,000
Weighted Average Fair Value of Options Granted During Year		\$-		
2012:				
Beginning Balance	262,463	\$-	-	\$-
Granted	-	-	-	-
Exercised	(10,500)	5.18	-	-
Forfeited	-	-	-	-
Outstanding at December 31	251,963	5.18	4.8	2,933,000
Exercisable	251,963	5.18	4.8	2,933,000
Ending Vested	251,963	5.18	4.8	2,933,000
Weighted Average Fair Value of Options Granted During Year		\$-		

2011:

Beginning Balance	265,963	\$-	-	\$-
Granted	-	-	-	-
Exercised	(3,500)	5.18	-	-
Forfeited	-	-	-	-
Outstanding at December 31	262,463	5.18	5.8	4,934,000
Exercisable	262,463	5.18	5.8	4,934,000
Ending Vested	262,463	5.18	5.8	4,934,000
Weighted Average Fair Value of Options Granted During Year		\$-		

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Currently Outstanding Options

- No options were forfeited during the years ended December 31, 2013, 2012, and 2011.
 - No options expired during the years ended December 31, 2013, 2012, and 2011.
- Options covering 241,872 shares were exercisable and outstanding at December 31, 2013.
- The Company recorded no compensation expense related to these options for the years ended December 31, 2013, 2012, and 2011. All of the compensation expense was reported in 2008 when the options vested. There is no further compensation expense that will be recognized in future periods relative to any options that had been granted as of December 31, 2013, because the Company recognized the entire fair value of such compensation upon vesting of the options.
 - There were no unvested options at December 31, 2013, 2012, and 2011.

Warrants Granted February 2009

On February 27, 2009, in conjunction with the closing of a prior revolving credit facility, the Company issued warrants to purchase a total of 300,000 shares of common stock exercisable at \$5.00 per share. The total fair value of the warrants was calculated using the Black-Scholes valuation model based on factors present at the time the warrants were issued. The fair value of the warrants is included in debt issuance costs and is being amortized over the term of the facility. The warrants were exercised in January 2011.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to, court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

The Company is party to a quiet title action in North Dakota that relates to its interest in certain crude oil and natural gas leases. In the event the action results in a final judgment that is adverse to the Company, the Company would be required to reverse approximately \$1.5 million in revenue (net of accrued taxes) that has been accrued since the second quarter of 2008 based on the Company's purported interest in the crude oil and natural gas leases at issue, \$0.3 million, \$0.2 million and \$0.2 million of which relates to the years ended December 31, 2013, 2012 and 2011, respectively. The Company fully maintains the validity of its interest in the crude oil and natural gas leases, and is vigorously defending such interest.

NOTE 9 ASSET RETIREMENT OBLIGATION

The Company has asset retirement obligations ("ARO") associated with the future plugging and abandonment of proved properties and related facilities. Initially, the fair value of a liability for an ARO is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. No settlements of asset retirement obligations have occurred during the periods presented.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO, a corresponding adjustment is made to the oil and gas property balance. For example, as the Company analyzes actual plugging and abandonment information, the Company may revise its estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of its wells. During 2013, the Company increased its existing ARO by \$1.1 million or approximately 71% of the ARO liability at December 31, 2012. This increase was due to an increase in the estimated costs to plug and abandon the Company's wells and a decrease in the productive life of certain of its oil and gas properties.

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The following table summarizes the company's asset retirement obligation transactions recorded during the year ended December 31, 2013 and 2012.

	Year Ended December 31	
	2013	2012
Beginning Asset Retirement Obligation	\$1,542,542	\$916,622
Liabilities Incurred for New Wells Placed in Production	755,484	539,727
Revision of Estimates	1,097,097	-
Accretion of Discount on Asset Retirement Obligations	428,879	86,193
Ending Asset Retirement Obligation	\$3,824,002	\$1,542,542

NOTE 10 INCOME TAXES

The Company utilizes the asset and liability approach to measuring deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

In 2013, the State of North Dakota lowered its corporate income tax rate. The impact of this rate change was to lower the Company's deferred state income tax expense by approximately \$0.5 million during the year ended December 31, 2013.

The income tax provision for the year ended December 31, 2013, 2012, and 2011 consists of the following:

	2013	2012	2011
Current Income Taxes	\$(8,386)	\$17,772	\$2,300
Deferred Income Taxes			
Federal	29,826,000	39,850,000	22,982,000
State	1,950,000	3,134,000	3,851,000
Total Expense	\$31,767,614	\$43,001,772	\$26,835,300

The following is a reconciliation of the reported amount of income tax expense for the years ended December 31, 2013, 2012, and 2011 to the amount of income tax expenses that would result from applying the statutory rate to pretax income.

Reconciliation of reported amount of income tax expense:

	2013	2012	2011
Income Before Taxes and NOL	\$84,834,650	\$115,286,396	\$67,446,792
Federal Statutory Rate	X 35 %	X 35 %	X 35 %
Taxes Computed at Federal Statutory Rates	29,692,000	40,350,000	23,606,000
State Taxes, Net of Federal Taxes	909,614	2,086,772	2,408,300
Executive Compensation Deductibility Limits	987,000	523,000	617,000
Other	179,000	42,000	204,000
Reported Provision	\$31,767,614	\$43,001,772	\$26,835,300

At December 31, 2013, the Company had a net operating loss carryforward for Federal income tax purposes of \$850.1 million. If unutilized, the federal net operating losses will expire in 2027-2033.

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The components of the Company's deferred tax asset (liability) were as follows:

	Year Ended December 31,	
	2013	2012
Deferred Tax Assets		
Current:		
Share Based Compensation	\$ 1,834,000	\$ 2,384,000
Accrued Interest	1,241,000	751,000
Derivative Instruments	7,094,000	-
Other	391,000	201,000
Total Current	10,560,000	3,336,000
Non-Current:		
Net Operating Loss Carryforwards (NOLs)	316,266,000	256,473,000
Derivative Instruments	-	295,000
Other	69,000	65,000
Total Non-Current	316,335,000	256,833,000
Total Deferred Tax Asset	\$ 326,895,000	\$ 260,169,000
Deferred Tax Liabilities		
Current:		
Derivative Instruments	-	(1,538,000)
Other	(129,000)	(103,000)
Total Current	\$(129,000)	\$(1,641,000)
Non-Current:		
Crude Oil and Natural Gas Properties and Other Property	(432,596,000)	(333,008,000)
Derivative Instruments	(413,000)	-
Total Non-Current	(433,009,000)	(333,008,000)
Total Deferred Tax Liability	(433,138,000)	(334,649,000)
Total Net Deferred Tax Liability	\$(106,243,000)	\$(74,480,000)

The balances in the components of deferred tax asset (liability) table above were corrected to increase the deferred tax asset for net operating losses and the deferred tax liability for crude oil and natural gas properties and other property by approximately \$62 million. The adjustment had no impact to the total net deferred tax liability.

Tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards.

The Company has no liabilities for unrecognized tax benefits.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the years ended December 31, 2013, 2012 and 2011, the Company did not recognize

any interest or penalties in its statements of comprehensive income, nor did it have any interest or penalties accrued in its balance sheet at December 31, 2013 and 2012 relating to unrecognized benefits.

The tax years 2013, 2012, 2011 and 2010 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject.

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NOTE 11 OPERATING LEASES

Vehicles

The Company leases vehicles under noncancelable operating leases. Total lease expense under the agreements was approximately \$28,000, \$48,000 and \$63,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

Minimum future lease payments under these vehicle leases are approximately \$27,000 in 2014.

Building

Effective November 2011, the Company extended their original operating lease agreement on 3,044 square feet of office space and added an additional 1,609 square feet of office space, for a total of 4,653 square feet. The two leases require initial gross monthly lease payments of \$18,612. The monthly payments increase by 4% on each anniversary date. The leases expire in November 2015. The Company also has annual and month to month lease agreements related to storage and parking spaces. Total rent expense under the agreements was approximately \$249,000, \$217,000 and \$150,000 for the years ended December 31, 2013, 2012, and 2011, respectively.

The Company has prepaid the last three months rent in the amount of \$53,553. Minimum future lease payments under the building leases are as follows:

Year Ended December 31,	Amount
2014	\$278,000
2015	177,000
	Total \$455,000

The Company received \$91,320 of landlord incentives under the original lease agreement and an additional \$58,620 under the lease for the additional 1,609 square feet. The Company has recorded a deferred rent liability for these amounts that are being amortized over the term of the leases.

NOTE 12 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

The following schedule summarizes the valuation of financial instruments measured at fair value on a recurring basis in the balance sheet as of December 31, 2013 and 2012.

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	Fair Value Measurements at December 31, 2013 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Asset (crude oil swaps and collars)	\$-	\$62,890	\$ -
Commodity Derivatives – Current Liability (crude oil swaps and collars)	-	(19,119,646)	-
Commodity Derivatives – Non-Current Asset (crude oil swaps and collars)	-	1,745,405	-
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(637,208)	-
Total	-	\$(17,948,559)	\$ -

	Fair Value Measurements at December 31, 2012 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives – Current Asset (crude oil swaps and collars)	\$-	\$4,095,197	\$ -
Commodity Derivatives – Non-Current Asset (crude oil swaps and collars)	-	1,763,008	-
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(2,547,745)	-
Total	\$-	\$3,310,460	\$ -

Level 2 assets and liabilities consist of derivative assets and liabilities (see Note 14), the Revolving Credit Facility (see Note 4) and the Notes (see Note 4). The fair value of the Company's derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of all derivative contracts is reflected on the balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent year. The book value of the Revolving Credit Facility approximates fair value because of its floating rate structure. The fair value of our 8% senior notes is based on an end of period market quote.

The Company's long-term debt is not measured at fair value on the balance sheets and the fair value is being provided for disclosure purposes. At December 31, 2013, the Company had \$500 million of senior unsecured notes and \$75 million under the Revolving Credit Facility outstanding with a fair value of \$527.5 million and \$75 million, respectively. At December 31, 2012, the Company had \$300 million of senior unsecured notes and \$124 million

under the Revolving Credit Facility outstanding with a fair value of \$310.5 million and \$124.0 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable inputs regarding interest rates available to the Company at the end of each respective period.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the years ended December 31, 2013 and 2012.

NOTE 13 FINANCIAL INSTRUMENTS

The Company's non-derivative financial instruments include cash and cash equivalents, and credit facility and are not measured at fair value on the balance sheets. The carrying amount of these non-derivative financial instruments approximate their fair values (See Note 12).

The Company's accounts receivable relate to crude oil and natural gas sold to various industry companies. Credit terms, typical of industry standards, are of a short-term nature and the Company does not require collateral. Management believes the Company's accounts receivable at December 31, 2013 and 2012 do not represent significant credit risks as they are dispersed across many counterparties. As of December 31, 2013, outstanding derivative contracts with commercial banks participating in the revolving credit facility represent all of the Company's crude oil volumes hedged. These commercial banks have investment-grade ratings from Moody's and Standard & Poor and are lenders under the Company's revolving credit facility and management believes this does not represent a significant credit risk.

NOTE 14 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity swap contracts and costless collars (purchased put options and written call options) to (i) reduce the effects of volatility in price changes on the crude oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and, in addition, the Company has elected not to designate any subsequent derivative contracts as cash flow hedges. Beginning on November 1, 2009, all derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives are recorded to gain or loss on settled derivatives and gains or losses on the mark-to-market of derivative instruments are recorded to (loss) gain on the mark-to-market of derivative instruments on the statement of comprehensive income rather than as a component of other comprehensive income (loss) or other income (expense).

The Company has master netting agreements on individual crude oil contracts with certain counterparties and therefore the current asset and liability are netted on the balance sheet and the non-current asset and liability are netted on the balance sheet for contracts with these counterparties.

Crude Oil Derivative Contracts Cash-flow Hedge

Prior to November 1, 2009, all derivative positions that qualified for hedge accounting were designated on the date the Company entered into the contract as a hedge against the variability in cash flows associated with the forecasted sale of future crude oil production. The cash flow hedges were valued at the end of each period and adjustments to the fair value of the contract prior to settlement were recorded on the statement of stockholders' equity as other comprehensive income. Upon settlement, the gain (loss) on the cash flow hedge was recorded as an increase or decrease in revenue on the statements of comprehensive income. The Company reports average crude oil and natural gas prices and revenues including the net results of hedging activities.

The net mark-to-market loss on the Company's remaining swaps that qualified for cash flow hedge accounting at the date the decision was made to discontinue hedge accounting totaled approximately \$101,000 as of December 31, 2011. The Company has recorded that amount as accumulated other comprehensive income in stockholders' equity

and the entire amount was amortized into revenues as the original forecasted hedged crude oil production occurred in the first quarter of 2012.

Crude Oil Derivative Contracts Cash-flow Not Designated as Hedges

The Company recorded realized losses on settled derivatives of \$12.2 million, \$0.4 million and \$13.4 million as a loss on settled derivatives in the statement of comprehensive income for the years ended December 31, 2013, 2012 and 2011, respectively. The Company recorded (losses) gains of \$(21.3) million, \$15.1 million and \$3.1 million as (losses) gains on the mark-to-market of derivatives in the statement of comprehensive income for the years ended December 31, 2013, 2012 and 2011, respectively. Mark-to-market gains and losses represent changes in fair values of derivatives that have not been settled.

The following table reflects open commodity swap contracts as of December 31, 2013, the associated volumes and the corresponding fixed price.

Settlement Period	Oil (Barrels)	Fixed Price
Swaps-Crude Oil		
01/01/14 – 06/30/14	300,000	\$89.50
01/01/14 – 06/30/14	240,000	90.00
01/01/14 – 06/30/14	240,000	100.00
01/01/14 – 12/31/14	240,000	91.65
01/01/14 – 12/31/14	345,000	88.55
01/01/14 – 12/31/14	345,000	88.60
01/01/14 – 12/31/14	345,000	88.40
01/01/14 – 12/31/14	345,000	88.50
01/01/14 – 12/31/14	120,000	91.35
01/01/14 – 12/31/14	120,000	90.00
01/01/14 – 12/31/14	240,000	90.15
01/01/14 – 12/31/14	240,000	91.00
01/01/14 – 12/31/14	120,000	93.00
07/01/14 – 12/31/14	120,000	90.00
07/01/14 – 12/31/14	120,000	90.00
07/01/14 – 12/31/14	120,000	93.50
07/01/14 – 12/31/14	30,000	90.58
01/01/14 – 06/30/15	480,000	89.15
01/01/15 – 06/30/15	60,000	90.50
01/01/15 – 06/30/15	180,000	88.55
01/01/15 – 06/30/15	180,000	88.00
01/01/15 – 06/30/15	60,000	90.75
01/01/15 – 06/30/15	60,000	90.25
01/01/15 – 06/30/15	90,000	89.00
01/01/15 – 06/30/15	90,000	89.00
01/01/15 – 12/31/15	720,000	89.00
01/01/15 – 12/31/15	360,000	89.00
01/01/15 – 12/31/15	360,000	89.02
01/01/15 – 12/31/15	180,000	89.00
01/01/15 – 12/31/15	180,000	89.00

As of December 31, 2013, the Company had a total volume on open commodity swaps of 6.6 million barrels at a weighted average price of approximately \$89.84.

The following table reflects the weighted average price of open commodity derivative contracts as of December 31, 2013, by year with associated volumes.

Year	Weighted Average Price Of Open Commodity Swap Contracts	
	Volumes (Bbl)	Weighted Average Price

2014	3,750,000	\$90.46
2015	2,880,000	89.02

In addition to the open commodity swap contracts the Company has entered into costless collars. The costless collars are used to establish floor and ceiling prices on anticipated crude oil production. There were no premiums paid or received by the Company related to the costless collar agreements. The following table reflects open costless collar agreements as of December 31, 2013.

Term	Oil (Barrels)	Floor/Ceiling Price	Basis
Costless Collars – Crude Oil			
01/01/14 – 12/31/14	240,000	\$ 90.00/\$99.05	NYMEX

We determine the estimated fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets and quotes from third parties, among other things. The Company also performs an internal valuation to ensure the reasonableness of third party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. For further details regarding our derivative contracts see Note 12, Fair Value in the Notes to the Financial Statements.

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at December 31, 2013 and 2012, respectively. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement:

Type of Crude Oil Contract	Balance Sheet Location	December 31, Estimated Fair Value	
		2013	2012
Derivative Assets:			
Swap Contracts	Current assets/liabilities	\$ 62,890	\$ 680,647
Swap Contracts	Non-current assets	1,745,405	1,977,722
Costless Collars	Current assets/liabilities	-	11,769,415
Costless Collars	Non-current asset/liabilities	-	5,629,996
Total Derivative Assets		\$ 1,808,295	\$ 20,057,780
Derivative Liabilities:			
Swap Contracts	Current assets/liabilities	\$ (19,111,820)	\$ (2,037,070)
Swap Contracts	Non-current assets	(637,208)	(3,170,945)
Costless Collars	Current assets/liabilities	(7,826)	(6,317,795)
Costless Collars	Non-current assets/liabilities	-	(5,221,510)
Total Derivative Liabilities		\$ (19,756,854)	\$ (16,747,320)

The following disclosures are applicable to the Company's financial statements, as of December 31, 2013, 2012 and 2011:

Derivative Type	Location of Loss for Effective and Ineffective Portion of Derivative in Income	Amount of Loss Reclassified from AOCI into Income Year Ended December 31,		
		2013	2012	2011
		Commodity – Cash Flow	Loss on Settled Derivatives	\$ -

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted on the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected on the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

Estimated Fair Value at December 31, 2013

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	\$ 629,178	\$ (566,288)	\$ 62,890
Non-Current Assets	2,589,079	(843,674)	1,745,405
Total Derivative Assets	\$ 3,218,257	\$ (1,409,962)	\$ 1,808,295
Offsetting of Derivative Liabilities:			
Current Liabilities	\$ (19,685,934)	\$ 566,288	\$ (19,119,646)
Non-Current Liabilities	(1,480,882)	843,674	(637,208)
Total Derivative Liabilities	\$ (21,166,816)	\$ 1,409,962	\$ (19,756,854)

Estimated Fair Value at December 31, 2012

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	\$ 12,450,062	\$ (8,354,865)	\$ 4,095,197
Non-Current Assets	7,607,718	(5,844,710)	1,763,008
Total Derivative Assets	\$ 20,057,780	\$ (14,199,575)	\$ 5,858,205
Offsetting of Derivative Liabilities:			
Current Liabilities	\$ (8,354,865)	\$ 8,354,865	\$ -
Non-Current Liabilities	(8,392,455)	5,844,710	(2,547,745)
Total Derivative Liabilities	\$ (16,747,320)	\$ 14,199,575	\$ (2,547,745)

NOTE 15 EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator used to calculate basic earnings per share and diluted earnings per share for the years ended December 31, 2013, 2012, and 2011:

	2013			2012			2011		
	Net Income	Shares	Per Share	Net Income	Shares	Per Share	Net Income	Shares	Per Share
Basic									
EPS	\$53,067,036	62,364,957	\$0.85	\$72,284,624	62,485,836	\$1.16	\$40,611,492	61,789,289	\$0.66
Dilutive Effect	-	382,341	-	-	383,243	(0.01)	-	406,051	(0.01)

of
Options
Diluted

EPS	\$53,067,036	62,747,298	\$0.85	\$72,284,624	62,869,079	\$1.15	\$40,611,492	62,195,340	\$0.65
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For the year ended December 31, 2013 and 2012 restricted stock of 7,330 and 18,348 shares of common stock were excluded from EPS due to the anti-dilutive effect.

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NOTE 16 EMPLOYEE BENEFIT PLANS

In 2009, the Company adopted a defined contribution 401(k) plan for substantially all of its employees. The plan provides for Company matching of employee contributions to the plan. During 2013, 2012 and 2011, the Company provided a match contribution equal to 100% of an eligible employee's deferral contribution, up to 8% of the employee's earnings up to the maximum allowable amount. The Company contributed approximately \$240,000, \$189,000 and \$103,000 to the 401(k) plan for the years ended December 31, 2013, 2012 and 2011, respectively.

NOTE 17 SEVERANCE ARRANGEMENTS

The Company's former president, Ryan Gilbertson, resigned effective October 1, 2012. In connection with his resignation, the Company and Mr. Gilbertson entered into a separation and release agreement and a consulting agreement (collectively, the "New Agreements"), which terminate and supersede his prior employment agreement with the Company (except for certain surviving provisions). Pursuant to the New Agreements, Mr. Gilbertson's outstanding and unvested restricted stock awards will continue to vest on their original vesting schedules, so long as Mr. Gilbertson does not terminate the consulting agreement and the Company does not terminate the consulting agreement for cause (as defined). In addition, pursuant to the New Agreements the Company (i) provided Mr. Gilbertson with a prorated portion of his 2012 year-end bonus (based on predetermined performance metrics and as determined by the Company's compensation committee following the end of 2012), (ii) bought out the lease and transferred title to Mr. Gilbertson on his Company-leased vehicle, and (iii) is reimbursing Mr. Gilbertson for continuation coverage pursuant to COBRA on the Company's health plans for up to 18 months.

In connection with the New Agreements, the Company concluded the unvested restricted stock awards were modified in connection with the change in Mr. Gilbertson's employment status and service requirements. Because the Company expects Mr. Gilbertson's awards will vest under the modified conditions but his period of active service in substance has concluded, \$4.3 million of share based compensation costs was reflected in general and administrative expense during the third quarter of 2012 related to the modified awards. Additionally, the cash expenses estimated for Mr. Gilbertson's prorated 2012 bonus, Company-leased vehicle and continuation coverage pursuant to COBRA was estimated at approximately \$0.6 million and was reflected in general and administrative expense during the third quarter of 2012.

On October 16, 2012, the Company terminated the employment of its Chief Operating Officer, James R. Sankovitz. Mr. Sankovitz's termination was "not for cause" under his existing employment agreement with the Company, and as a result he was entitled to certain severance benefits which included a single lump-sum payment of one times his \$325,000 base salary. In addition, the Company agreed to buy out the lease and transfer title to Mr. Sankovitz on his Company-leased vehicle, and reimburse Mr. Sankovitz for continuation coverage pursuant to COBRA on the Company's health plans for up to 18 months.

SUPPLEMENTAL OIL AND GAS INFORMATION
(UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

Oil and gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the company's crude oil and natural gas production activities are provided in the Company's related statements of income.

Costs Incurred and Capitalized Costs

The costs incurred in crude oil and natural gas acquisition, exploration and development activities are highlighted in the table below.

	Year Ended December 31,		
	2013	2012	2011
Costs Incurred for the Year:			
Proved Property Acquisition and Other	\$29,404,632	\$24,791,828	\$53,497,199
Unproved Property Acquisition	20,207,844	27,304,425	57,867,660
Development	389,491,634	485,392,505	302,594,511
Total	\$439,104,110	\$537,488,758	\$413,959,370

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2013 by year incurred.

	Year Ended December 31,			
	2013	2012	2011	Prior Years
Property Acquisition	\$17,086,145	\$8,076,277	\$22,875,092	\$22,110,834
Development	-	-	-	-
Total	\$17,086,145	\$8,076,277	\$22,875,092	\$22,110,834

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to the Company's crude oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by Ryder Scott Company, independent petroleum consultants based on information provided by the Company.

Oil and Natural Gas Reserve Data

The following tables present the Company's independent petroleum consultants' estimates of its proved crude oil and natural gas reserves. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Natural Gas (MCF)	Oil (BBLs)
Proved Developed and Undeveloped Reserves at December 31, 2010	10,449,962	13,993,697
Revisions of Previous Estimates	(940,065)	924,434
Extensions, Discoveries and Other Additions	20,959,474	28,750,826
Production	(800,207)	(1,791,979)
Proved Developed and Undeveloped Reserves at December 31, 2011	29,669,164	41,876,978
Revisions of Previous Estimates	(1,410,547)	812,371
Extensions, Discoveries and Other Additions	14,788,384	21,490,244
Production	(1,768,872)	(3,465,312)
Proved Developed and Undeveloped Reserves at December 31, 2012	41,278,129	60,714,281
Revisions of Previous Estimates	(8,634,689)	(12,749,049)
Extensions, Discoveries and Other Additions	20,096,944	31,880,594
Production	(2,572,251)	(4,046,701)
Proved Developed and Undeveloped Reserves at December 31, 2013	50,168,133	75,799,125
Proved Developed Reserves:		
December 31, 2010	3,513,427	5,840,745
December 31, 2011	8,452,653	14,338,576
December 31, 2012	17,350,166	27,345,824
December 31, 2013	20,642,967	32,043,405
Proved Undeveloped Reserves		
December 31, 2010	6,936,535	8,152,952
December 31, 2011	21,216,511	27,538,402
December 31, 2012	23,927,963	33,368,457
December 31, 2013	29,525,166	43,755,720

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932-235-555. Future cash inflows were computed by applying average prices of crude oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses were calculated by applying appropriate year end tax rates to future pretax cash flows relating to proved crude oil and natural gas reserves, less the tax basis of properties involved and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted future cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company's crude oil and natural gas reserves.

	Year Ended December 31,		
	2013	2012	2011
Future Cash Inflows	\$6,932,701,500	\$5,353,167,000	\$3,959,403,500
Future Production Costs	(2,093,282,688)	(1,436,711,062)	(925,165,656)
Future Development Costs	(1,281,664,750)	(846,363,500)	(624,607,500)
Future Income Tax Expense	(952,120,002)	(817,296,323)	(740,132,743)
Future Net Cash Inflows	\$2,605,634,060	\$2,252,796,115	\$1,669,497,601
10% Annual Discount for Estimated Timing of Cash Flows	(1,381,267,234)	(1,211,441,321)	(830,800,217)
Standardized Measure of Discounted Future Net Cash Flows	\$1,224,366,826	\$1,041,354,794	\$838,697,384

The twelve month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company's reserves. The price of other liquids is included in natural gas. The prices for the Company's reserve estimates were as follows:

	Natural Gas MCF	Oil Bbl
December 31, 2013	\$5.23	\$88.00
December 31, 2012	\$4.78	\$84.92
December 31, 2011	\$6.18	\$90.17

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum follow:

	Year Ended December 31,		
	2013	2012	2011
Beginning of Period	\$1,041,354,794	\$838,697,384	\$210,612,791
Sales of Oil and Natural Gas Produced, Net of Production Costs	(292,369,010)	(235,769,953)	(132,095,155)
Extensions and Discoveries	640,467,848	455,623,034	756,304,288
Previously Estimated Development Cost Incurred During the Period	139,069,899	193,669,706	23,941,194
Net Change of Prices and Production Costs	16,693,046	(179,505,191)	140,217,589

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Change in Future Development Costs	45,583,609	(112,995,358)	(11,285,152)
Revisions of Quantity and Timing Estimates	(454,395,244)	15,687,427	13,491,953
Accretion of Discount	128,740,632	110,133,321	29,551,146
Change in Income Taxes	(50,871,552)	16,584,302	(177,737,162)
Other	10,092,804	(60,769,878)	(14,304,107)
End of Period	\$1,224,366,826	\$1,041,354,794	\$838,697,384

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QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Quarterly data for the years end December 31, 2013 and 2012 is as follows:

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2013				
Total Revenues	\$67,898,082	\$96,161,803	\$69,784,200	\$101,929,786
(Losses) Gains on the Mark-to-Market of Derivative Instruments	(14,910,655)	17,009,668	(29,353,161)	5,995,130
Expenses	47,234,013	48,432,751	57,671,154	64,439,006
Income from Operations	20,664,069	47,729,052	12,113,046	37,490,780
Other Income (Expense)	(6,107,936)	(8,087,379)	(9,382,142)	(9,584,840)
Income Tax Provision	5,604,614	14,630,000	1,028,000	10,505,000
Net Income	8,951,519	25,011,673	1,702,904	17,400,940
Net Income Per Common Share – Basic	0.14	0.40	0.03	0.28
Net Income Per Common Share – Diluted	0.14	0.39	0.03	0.28
2012				
Total Revenues	\$50,522,992	\$119,207,601	\$60,095,613	\$81,746,684
(Losses) Gains on the Mark-to-Market of Derivative Instruments	(9,364,913)	49,799,311	(22,308,470)	(2,978,806)
Expenses(1)	35,695,832	44,013,801	54,376,314	48,350,512
Income from Operations	14,827,160	75,193,800	5,719,299	33,396,172
Other Income (Expense)	(195,899)	(2,727,404)	(5,205,716)	(5,721,016)
Income Tax Provision	5,825,350	28,840,000	213,422	8,123,000
Net Income	8,805,911	43,626,396	300,161	19,552,156
Net Income Per Common Share – Basic	0.14	0.70	-	0.31
Net Income Per Common Share – Diluted	0.14	0.70	-	0.31

(1) General and administrative expenses include \$5.5 million and \$0.6 million in severance expenses in connection with the departures of our president and our chief operating officer in the third and fourth quarters of 2012, respectively.

