NORTHERN OIL & GAS, INC.
Form 10-K
February 29, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

Or

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

For the transition period from ________ to ________

Commission File No. 001-33999

____

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

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

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	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	NYSE Amex Equities Market

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 ý No ¨

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

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

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

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

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 ý	Accelerated Filer ¨	Non-Accelerated Filer ¨ (Do not check if a smaller reporting company)	Smaller Reporting Company ¨

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sale price as reported by the NYSE Amex Equities Market) was approximately $1.296 billion.

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 15, 2012, the registrant had 63,481,852 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2012 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” – barrel or barrels.

“BOE” – barrels of crude oil equivalent.

“Boepd” – barrels of crude oil equivalent per day.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of crude oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbls” – million barrels.

“MMBoe” – million barrels of crude oil equivalent.

“MMbtu” – million British thermal units.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

“MMcfepd” – million cubic feet of gas equivalent per day.

“MMcfpd” – million cubic feet of gas per day.

“NGL” – natural gas liquids.

Terms used to describe our interests in wells and acreage:

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

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

"Developed acreage" means 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” is a well drilled within the proved area of a crude oil 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 or natural gas reserves.

“Dry hole” is an exploratory or development well found to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as a crude oil or natural gas well.

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

“Gross acres” refer to the number of acres in which we own a gross working interest.

“Gross well” is a well in which we own a working interest.

“Held by production” is a provision in an oil and gas lease that extends a company’s right to operate a lease as long as the property produces a minimum quantity of crude oil and natural gas.

“Infill well” is 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” represent our percentage ownership of gross acreage. 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 acres under the bit” or “net acreage under the bit” means those net leased acres on which wells are spud, drilling, drilled, awaiting completion or completing in the spacing unit only, and not yet classified as developed acreage, regardless of whether or not such acreage contains proved reserves. Acreage included in spacing units of infill wells is not considered under the bit because such acreage was already previously classified as developed acreage when the initial well was completed in the subject spacing unit.

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

“NYMEX” means the New York Mercantile Exchange, which is a designated contract market that facilitates and regulates the trading of crude oil and natural gas contracts subject to NYMEX rules and regulations.

“OPEC” means the Organization of Petroleum Exporting Countries.

“Productive well” is an exploratory or a development well that is capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

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

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

"Working interest" means the right granted to the lessee of a property to explore for and to produce and own crude oil, 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:

"Proved reserves" – Proved crude oil and natural gas reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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 developed reserves (PDP's)" – Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil 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 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 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 (PUD's)" – Proved crude oil and natural gas 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 are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

"Probable reserves" – are those 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.

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

"Pre-tax PV-10% (PV-10)" – means 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.

“Standardized Measure” – means 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.

TABLE OF CONTENTS

		Page
	Part I	
Item 1.	Business	2
Item 1A.	Risk Factors	9
Item 1B.	Unresolved Staff Comments	20
Item 2.	Properties	20
Item 3.	Legal Proceedings	26
Item 4.	Mine Safety Disclosures	27
	Part II	
Item 5.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	28
Item 6.	Selected Financial Data	31
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	33
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	49
Item 8.	Financial Statements and Supplementary Data	50
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	50
Item 9A.	Controls and Procedures	50
Item 9B.	Other Information	53
	Part III	
Item 10.	Directors, Executive Officers and Corporate Governance	54
Item 11.	Executive Compensation	54
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	54
Item 13.	Certain Relationships and Related Transactions, and Director Independence	54
Item 14.	Principal Accountant Fees and Services	55
	Part IV	
Item 15.	Exhibits and Financial Statement Schedules	55
Signatures		56
Index to Financial Statements		F-1

NORTHERN OIL AND GAS, INC.

ANNUAL REPORT ON FORM 10-K

FOR FISCAL YEAR ENDED DECEMBER 31, 2011

PART I

Item 1. Business

Overview

We are a growth-oriented independent energy company engaged in the acquisition, exploration, development and production of crude oil and natural gas properties, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. We primarily engage in crude oil and natural gas exploration and production by participating on a "heads-up" basis alongside third-party interests in wells drilled and completed in spacing units that include our acreage. We typically depend on drilling partners to propose, permit and initiate the drilling of wells.

We believe that we are able to create value via strategic acreage acquisitions and convert that value or portion thereof into production by utilizing experienced industry partners specializing in the specific areas of interest. We have targeted specific prospects and have consistently participated in crude oil drilling activities in the Williston Basin region since the fourth fiscal quarter of 2007.

Our business approach is to identify and exploit repeatable and scalable resource plays that can be quickly developed in a cost effective manner. We also intend to take advantage of our expertise in aggressive land acquisition to continue to pursue exploration and development projects as a non-operating working interest partner, participating in drilling activities primarily on a heads-up basis proportionate to our working interest. Our business does not depend upon any intellectual property, licenses or other proprietary property unique to our company, but instead revolves around our ability to acquire mineral rights and participate in drilling activities by virtue of our ownership of such rights and through the relationships we have developed with our operating partners. We believe our competitive advantage lies in our ability to acquire property, specifically in the Williston Basin, in a nimble and efficient fashion.

We historically 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 continue to utilize a variety of methods to acquire properties, and are increasingly focusing our efforts on acquiring properties subject to specific drilling projects or included in permitted or drilling spacing units.

We are focused on maintaining a low cash overhead structure. We believe we are in a position to efficiently exploit and identify high production crude oil and natural gas properties due to our unique non-operator model through which we are able to diversify our risk and participate in the evolution of technology by the collective expertise of those operators with which we partner. We intend to continue to pursue acquisitions of crude oil, natural gas and mineral leases in desired prospects of the Williston Basin that generate attractive rates of return, complement our core areas and provide a portfolio of lower risk, long-lived oil and gas properties.

We acquired approximately 43,239 net mineral acres at an average cost of approximately $1,832 per net acre in 2011. Additionally, we participated in the completion of 354 gross wells with a 100% success rate in the Bakken and Three Forks formations during 2011. As of December 31, 2011, our principal assets included approximately 167,562 net acres located in the Williston Basin region of the northern United States and approximately 1,281 net acres located in Yates County, New York, as more fully described under the heading "Properties – Leasehold Properties" in Item 2.

Since inception we have drilled and completed, or are currently in the process of drilling and completing, 839 gross wells, consisting of five exploration and 834 developmental wells with a 100% success rate targeting the Bakken and Three Forks formations. At December 31, 2011, we owned working interests in 664 successful discoveries, consisting of 659 targeting the Bakken and Three Forks formations and five exploratory wells targeting other formations. As of December 31 2011, we had developed approximately 52,219 net acres and had approximately 17,290 net acres currently in the process of drilling and completing.

The following table provides information regarding our assets and operations.

At December 31, 2011					Year Ended December 31, 2011
			Productive Wells		Average Daily Production
Proved Reserves(a) (MBoe)	Pre-Tax PV10%(b)(c) (Thousands)	% Oil	Gross	Net	Volumes(d) (BOE)
46,822	$ 1,101,333	89 %	664	57.9	5,275

(a) MBoe is defined as one thousand barrels of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.
(b) The prices used to calculate this measure were $90.17 per barrel of crude oil and $6.18 per Mcf of natural gas, using a BTU factor of 1.5 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 crude 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.
(c) Pre-Tax PV 10% ("PV-10") may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 can be used with the industry and by creditors and security analysts to valuate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure at December 31, 2011, which was $839 million, and the PV-10 amount was discounted estimated future income tax of $263 million at December 31, 2011.
(d) Average daily production volumes calculated based on 365 day year. Average daily production on a BOE volume basis during the fourth quarter of 2011 was 6,950.

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 strategy include:

- Developing and exploiting our existing properties. 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.

- Maintain Long-Life Reserve Base. We focus our acreage acquisition and development activities on resources that target long-life oil and gas reserves. Long-life oil and gas reserves provide a more stable growth platform than short-life reserves. Long-life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life crude oil and natural gas reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale.

- Disciplined Financial Approach. 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 have historically funded our growth activity through a combination of equity and bank borrowings and internally generated cash flow, as appropriate, to maintain our strong financial position. We periodically enter into derivative contracts to support cash flow generation on our existing properties and help ensure expected cash flows from our properties. Typically, we use costless collars and fixed price oil contracts to provide an attractive base commodity price level.

Industry Operating Environment

The crude 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 crude 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 crude oil prices averaged $95.11 per barrel in 2011 with a high of $114.83 per barrel in May and a low of $74.95 per barrel in October. 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 crude 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. 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 crude 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 crude 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 substantially all, if not all, of the wells proposed to us.

We do not manage our commodities marketing activities internally, but our operating partners generally market and sell crude oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our crude oil production from our wells to appropriate pipelines 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 crude 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 2011 was $6.02 per barrel below NYMEX pricing. Our weighted average differential was approximately $5.01 during the fourth quarter of 2011. This differential represents the imbedded transportation costs in moving the crude oil from wellhead to refinery and will fluctuate based on availability of pipeline, rail and other transportation methods.

Competition

The crude oil and natural gas industry is intensely competitive, and we compete with numerous other crude 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 crude 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 crude 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 have the resources to be better able to absorb the burden of existing, and any changes to federal, state, and local laws and regulations more easily 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 crude 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 crude oil and natural gas that we will produce depends on factors beyond our control, including the extent of domestic production and imports of crude oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for crude oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The crude oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our crude oil production is expected to be sold at prices tied to the spot crude 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 involve 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 and obtain title opinions from counsel 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 crude 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 well is considered held by production. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production. Given the current pace of drilling in the Bakken play at this time, we do not believe lease expiration issues will materially affect our North Dakota position.

Governmental Regulation and Environmental Matters

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

5

Regulation of Crude Oil and Natural Gas Production

Our crude oil and natural gas exploration, production and related operations, when developed, 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 crude oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of crude 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 crude 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 crude 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 crude 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 Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350.0 million, while the liability limit for offshore facilities is the payment of all removal costs plus up to $75.0 million in other damages, but these limits may not apply if a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or if a party fails to report a spill or to cooperate fully in a cleanup. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's requirements will not have a material adverse effect on us.

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.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us or our operating partners to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. While we may be required (directly or indirectly through our operating partners) to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will have a material adverse effect on our operations.

Changes in environmental laws and regulations sometimes occur, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. See "climate change" below.

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.

The EPA had regulations under the authority of the CWA that required certain oil and gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the Energy Policy Act of 2005 nullified most of the EPA regulations that required storm water permitting of oil and gas construction projects. There are still some state and federal rules that regulate the discharge of storm water from some oil and gas construction projects. 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.

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 crude oil and natural gas exploration and production. Many states and the federal government have enacted legislation directed at controlling greenhouse gas emissions, and future legislation and regulation could impose additional restrictions or requirements in connection with our drilling and production activities and favor use of alternative energy sources, which could negatively impact operating costs and demand for crude oil products. As such, our business could be materially adversely affected by domestic and international legislation targeted at controlling climate change.

Employees

We currently have 19 full time employees. Our Chief Executive Officer and Chairman, Michael L. Reger, and our President, Ryan R. Gilbertson, are responsible for all material policy-making decisions. They are assisted in the implementation of our company's business by our Chief Financial Officer and our Chief Operating Officer. All employees have entered into written employment agreements. 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 drilling 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 under "Investor Relations," 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.

8

Item 1A. Risk Factors

Risks Related to our Business

The possibility of a global financial crisis may significantly impact our business and financial condition for the foreseeable future.

The credit crisis and related turmoil in the global financial system may adversely impact our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have a material negative impact on our flexibility to react to changing economic and business conditions. The economic situation could have a material negative impact on operators upon whom we are dependent for drilling our wells, our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have a material negative impact on our crude oil hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection. We believe we will have sufficient capital to fund our 2012 drilling program. However, additional capital would be required in the event that we accelerate our drilling program or that crude oil prices decline substantially resulting in significantly lower revenues.

We may be unable to obtain additional capital that we will require to implement our business plan, which could restrict our ability to grow.

We expect that our cash position, credit facility and revenues from crude oil and natural gas sales will be sufficient to fund our 2012 drilling program. However, those funds 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 via acquisitions and to further expand our exploration and development programs. We may be unable to obtain additional capital if and when required.

Future acquisitions and future exploration, development, production and marketing activities, as well as our administrative requirements (such as salaries, insurance expenses and general overhead expenses, as well as legal compliance costs and accounting expenses) will require a substantial amount of capital.

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 identifying suitable financing transactions in the time period required or at all, and we may not obtain the capital we require by other means. If we do not succeed in raising additional capital, our resources may not be sufficient to fund our planned expansion of operations in the future.

Any additional capital raised through the sale of equity may dilute the ownership percentage of our shareholders. Raising any such capital could also result in a decrease in the fair market value of our equity securities because our assets would be owned by a larger pool of outstanding equity. The terms of securities we issue in future capital transactions may be more favorable to our new investors, and may include preferences, superior voting rights and the issuance of other derivative securities. In addition, we have granted and will continue to grant equity incentive awards under our equity incentive plans, which may have a further dilutive effect.

Our ability to obtain financing, if and when necessary, may be impaired by such factors as the capital markets (both generally and in the crude oil and natural gas industry in particular), the location of our crude oil and natural gas properties and prices of crude oil and natural gas on the commodities markets (which will impact the amount of asset-based financing available to us) and the departure of key employees. Further, if crude oil or natural gas prices on the commodities markets decline, our revenues will likely decrease and such decreased revenues may increase our requirements for capital. If the amount of capital we are able to raise from financing activities, together with our revenues from operations, is not sufficient to satisfy our capital needs (even to the extent that we reduce our operations), we may be required to cease our operations, divest our assets at unattractive prices or obtain financing on unattractive terms.

We may incur substantial costs in pursuing future capital financing, including investment banking fees, legal fees, accounting fees, securities law compliance fees, printing and distribution expenses and other costs. We may also be required to recognize non-cash expenses in connection with certain securities we may issue, which may adversely impact our financial condition.

We are highly dependent on Michael Reger, our Chief Executive Officer, Chairman and Director, and Ryan Gilbertson, President. The loss of either of them, upon whose knowledge, leadership and technical expertise we rely, would harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of Michael Reger and Ryan Gilbertson, whose knowledge, leadership and technical expertise would be difficult to replace, and on our ability to retain and attract experienced engineers, geoscientists and other technical and professional staff. If we were to lose their services, our ability to execute our business plan would be harmed. Mr. Reger and Mr. Gilbertson have entered into employment agreements with our company; however, they may terminate their employment with our company at any time.

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

Our business focus is on the crude oil and natural gas industry in a limited number of properties, primarily in Montana and North Dakota. Other companies may have the ability to manage their risk by diversification. However, the narrow focus of our business, in terms of both the nature and geographic scope of our business, means that we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified. This enhances our risk profile. We do not currently intend to expand either the nature or geographic scope of our business.

Strategic relationships upon which we may rely are subject to change, which may diminish our ability to conduct our operations.

Our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements will depend on developing and maintaining close working relationships with industry participants and our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. These realities are subject to change and our inability to maintain close working relationships with industry participants or continue to acquire suitable property may impair our ability to execute our business plan.

To continue to develop our business, we will endeavor to use the business relationships of our management to enter into strategic relationships, which may take the form of joint ventures with other private parties and contractual arrangements with other crude oil and natural gas companies, including those that supply equipment and other resources that we will use in our business. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to in order to fulfill our obligations to these partners or maintain our relationships. If sufficient strategic relationships are not established and maintained, our business prospects, financial condition and results of operations may be materially adversely affected.

As a non-operator, our development of successful operations relies extensively on third-parties who, if not successful, could have a material adverse affect 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 consultants and drilling partners. As a result, we do not control the timing or success of the development, exploitation, production and exploration activities relating to our leasehold interests. If our consultants and drilling partners are not successful in such 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.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2011, all of our debt is at variable interest rates.

Continuing disruptions and volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital; a significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

Competition in obtaining rights to explore and develop crude oil and natural gas reserves and to market our production may impair our business.

The crude oil and natural gas industry is highly competitive. Other crude oil and natural gas companies may seek to acquire crude 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 crude 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.

We exist in a litigious environment.

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

We may not be able to effectively manage our growth, which may harm our profitability.

Our strategy envisions the expansion of our business. If we fail to effectively manage our growth, our financial results could be adversely affected. Growth may place a strain on our management systems and resources. We must continue to refine and expand our business capabilities, our systems and processes and our access to financing sources. As we grow, we must continue to hire, train, supervise and manage new employees. We cannot assure that we will be able to:

- meet our capital needs;
- expand our systems effectively or efficiently or in a timely manner;

- allocate our human resources optimally;
- identify and hire qualified employees or retain valued employees; or
- incorporate effectively the components of any business that we may acquire in our effort to achieve growth.

If we are unable to manage our growth, our financial condition and results of operations may be materially adversely affected.

Our derivatives activities could result in financial losses or could reduce our net income, which may adversely affect your investment in our common stock.

We generally expect to enter into swaps, collars or other derivatives arrangements from time-to-time to hedge our expected production depending on reserves and market conditions. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if crude oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

our production is less than expected;

there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement; or

the counterparties to our derivative agreements fail to perform under the contracts.

Risks Related To Our Industry

Crude oil and natural gas prices are very volatile. A protracted period of depressed crude oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The crude oil and natural gas markets are very volatile, and we cannot predict future crude oil and natural gas prices. The price we receive for our crude 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 crude oil and natural gas;

the actions of OPEC;

the price and quantity of imports of foreign crude oil and natural gas;

political and economic conditions, including embargoes, in crude oil-producing countries or affecting other crude oil-producing activity;

the level of global crude oil and natural gas exploration and production activity;

the level of global crude oil and natural gas inventories;

weather conditions;

technological advances affecting energy consumption;

domestic and foreign governmental regulations;

proximity and capacity of crude oil and natural gas pipelines and other transportation facilities;

the price and availability of competitors' supplies of crude oil and natural gas in captive market areas; and the price and availability of alternative fuels.

The recent worldwide financial and credit crisis reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets led to a worldwide economic recession. The slowdown in economic activity caused by future similar recessions could reduce worldwide demand for energy resulting in lower crude oil and natural gas prices and restrict our access to liquidity and credit.

Lower crude oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of crude oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in crude oil or natural gas prices may result in impairments of our proved crude 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 will be required to reduce spending or borrow to cover any such shortfall. Lower crude oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations, as well as special redeterminations described in the credit agreement.

Drilling for and producing crude oil and natural gas are high risk activities with many uncertainties.

Our future success will depend on the success of our development, exploitation, production and exploration activities. Our crude oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable crude oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion crews;
- equipment failures or accidents; and
- adverse weather conditions, such as freezing temperatures, hurricanes and storms.

The presence of one or a combination of these factors at our properties could adversely affect our business, financial condition or results of operations.

Our business of exploring for crude oil and natural gas is risky and may not be commercially successful, and the advanced technologies we use cannot eliminate exploration risk.

Our future success will depend on the success of our exploratory drilling program. Crude oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our ability to produce revenue and our resulting financial performance are significantly affected by the prices we receive for crude oil and natural gas produced from wells on our acreage. Especially in recent years, the prices at which crude oil and natural gas trade in the open market have experienced significant volatility and will likely continue to fluctuate in the foreseeable future due to a variety of influences including, but not limited to, the following:

- domestic and foreign demand for crude oil and natural gas by both refineries and end users;
- the introduction of alternative forms of fuel to replace or compete with crude oil and natural gas;

- domestic and foreign reserves and supply of crude oil and natural gas;

- competitive measures implemented by our competitors and domestic and foreign governmental bodies;

- political climates in nations that traditionally produce and export significant quantities of crude oil and natural gas (including military and other conflicts in the Middle East and surrounding geographic region) and regulations and tariffs imposed by exporting and importing nations;

- weather conditions; and

- domestic and foreign economic volatility and stability.

Our expenditures on exploration may not result in new discoveries of crude oil or natural gas in commercially viable quantities. Projecting the costs of implementing an exploratory drilling program is difficult due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over-pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Even when used and properly interpreted, three-dimensional (3-D) seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. Such data and techniques do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. In addition, the use of 3-D seismic data becomes less reliable when used at increasing depths. We could incur losses as a result of expenditures on unsuccessful wells. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

We may not be able to develop crude oil and natural gas reserves on an economically viable basis, and our reserves and production may decline as a result.

If we continue to succeed in discovering crude oil and/or natural gas reserves, we cannot assure that these reserves will be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional crude oil and natural gas reserves. Without the addition of reserves through acquisition, exploration or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the crude oil and natural gas we develop and to effectively distribute our production into our markets.

Future crude oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and mechanical conditions. While we will endeavor to effectively manage these conditions, we cannot be assured of doing so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our crude oil and natural gas interests.

Our business depends on crude oil and natural gas transportation and processing facilities, which are owned by third parties.

The marketability of our crude oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although the operators of our properties have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport crude oil and natural gas. If any of these third party pipelines and other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance or weather could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party crude oil transportation in the Williston Basin could materially affect our ability to market and deliver crude oil over what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Estimates of crude oil and natural gas reserves that we make may be inaccurate and our actual revenues may be lower than our financial projections.

We make estimates of crude oil and natural gas reserves, upon which we base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to crude 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, engineers and other advisors to make accurate assumptions. Economic factors beyond our control, such as crude oil and natural gas prices and interest rates, will also impact the value of our reserves.

Determining the amount of crude oil and natural gas recoverable from various formations where we have exploration and production activities involves great uncertainty. For example, in 2006, the North Dakota Industrial Commission published an article that identified three different estimates of generated crude oil recoverable from the Bakken formation. An organic chemist estimated 50% of the reserves in the Bakken formation to be technically recoverable, a crude oil company estimated a recovery factor of 18%, and values presented in the North Dakota Industrial Commission Oil and Gas Hearings ranged from 3 to 10%.

The process of estimating crude oil and natural gas reserves is complex and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our crude oil and natural gas interests.

Drilling new wells could result in new liabilities, which could endanger our interests in our properties and assets.

There are risks associated with the drilling of crude oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills, among others. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. We do not in all cases maintain insurance against these hazards, and any insurance we have will be subject to limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Crude oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

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

We may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which we use for production of crude 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.

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

We could be required to write down the carrying value of certain of our crude oil and natural gas properties. Writedowns may occur when crude 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 our 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 crude 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 crude 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, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Significant capital expenditures are required to 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 and debt and equity issuances. We have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas and our success in developing and producing new reserves. If our access to capital were limited due to numerous factors, which could include a decrease in revenues due to lower crude 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 monetization or access other methods of financing on an economic basis to 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 crude 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 crude oil prices) decline, it will have similar adverse effects on our reserves and borrowing base.

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

Because the rate of production from crude 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 crude 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 reserves are produced. Future crude 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 producing and unproved properties as well as lease undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

We may have difficulty distributing our production, which could harm our financial condition.

In order to sell the crude oil and natural gas that we are able to produce, the operators of our wells may have to make arrangements for storage and distribution to the market. We will rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This situation could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. These factors may affect our ability to explore and develop properties and to store and transport our crude oil and natural gas production and may increase our expenses.

Furthermore, weather conditions or natural disasters, actions by companies doing business in one or more of the areas in which we will operate, or labor disputes may impair the distribution of crude oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

Environmental risks may adversely affect our business.

All phases of the crude 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 crude 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. Compliance with such legislation can require significant expenditures, and a breach may result in the imposition of fines and penalties, some of which may be material. 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 crude 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. The application of environmental laws to our business may cause us to curtail our 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.

The U.S. Congress is considering legislation that would amend the federal Safe Drinking Water Act by repealing an exemption for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of crude oil and natural gas wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate production. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The legislation also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could 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, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our business will suffer if we cannot obtain or maintain necessary licenses.

Our operations require licenses, permits and in some cases renewals of licenses and permits from various governmental authorities. Our ability to obtain, sustain or renew such licenses and permits on acceptable terms is subject to change in regulations and policies and to the discretion of the applicable governmental authorities, among other factors. Our inability to obtain, or our loss of or denial of extension of, any of these licenses or permits could hamper our ability to produce revenues from our operations or otherwise materially adversely affect our financial condition and results of operations.

Challenges to our properties may impact our financial condition.

Title to crude oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While we intend to make appropriate inquiries into the title of properties and other development rights we acquire, title defects may exist. In addition, we may be unable to obtain adequate insurance for title defects, on a commercially reasonable basis or at all. If title defects do exist, it is possible that we may lose all or a portion of our right, title and interests in and to the properties to which the title defects relate. If our property rights are reduced, our ability to conduct our exploration, development and production activities may be impaired. To mitigate title problems, common industry practice is to obtain a title opinion from a qualified crude oil and natural gas attorney prior to the drilling operations of a well.

We rely on technology to conduct our business, and such technology could become ineffective or obsolete.

We rely (both directly and through our third party operating partners) on technology, including geographic and seismic analysis techniques and economic models, to develop reserve estimates and to guide exploration, development and production activities. We will be required to continually enhance and update our technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial and may be higher than the costs that we anticipate for technology maintenance and development. If we are unable to maintain the efficacy of our technology, our ability to manage our business and to compete may be impaired. Further, even if we are able to maintain technical effectiveness, the chosen technology may not be the most efficient means of reaching our objectives, in which case we may incur higher operating costs than we would were our technology more efficient.

Risks Related to our Common Stock

The market price of our common stock is, and is likely to continue to be, highly volatile and subject to wide fluctuations.

The market price of our common stock is likely to continue to be highly volatile and could be subject to wide fluctuations in response to a number of factors, some of which are beyond our control, including:

- dilution caused by our issuance of additional shares of common stock and other forms of equity securities, which we expect to make in connection with future capital financings to fund our operations and growth, to attract and retain valuable personnel and in connection with future strategic partnerships with other companies;
- announcements of new acquisitions, reserve discoveries or other business initiatives by us or third parties;
- our ability to take advantage of new acquisitions, reserve discoveries or other business initiatives;
- fluctuations in revenue from our crude oil and natural gas business as new reserves come to market;

changes in the market for crude oil and natural gas commodities and/or in the capital markets generally;

changes in the demand for crude oil and natural gas, including changes resulting from economic conditions, governmental regulation or the introduction or expansion of alternative fuels;

quarterly variations in our revenues and operating expenses;

changes in the valuation of similarly situated companies, both in our industry and in other industries;

changes in analysts' estimates affecting our company, our competitors and/or our industry;

changes in the accounting methods used in or otherwise affecting our industry;

additions and departures of key personnel;

announcements of technological innovations or new products available to the crude oil and natural gas industry;

announcements by relevant governments pertaining to incentives for alternative energy development programs;

fluctuations in interest rates and the availability of capital in the capital markets; and

significant sales of our common stock, including sales by selling shareholders following the registration of shares under a prospectus.

Some of these and other factors are largely beyond our control, and the impact of these risks, singly or in the aggregate, may result in material adverse changes to the market price of our common stock and/or our results of operations and financial condition.

Our operating results may fluctuate significantly, and these fluctuations may cause the price of our common stock to decline.

Our operating results will likely vary in the future primarily as the result of fluctuations in our revenues and operating expenses, including the coming to market of crude oil and natural gas reserves that we are able to discover and develop, expenses that we incur, the prices of crude oil and natural gas in the commodities markets and other factors. If our results of operations do not meet the expectations of current or potential investors or analysts, the price of our common stock may decline.

Shareholders will experience dilution upon the exercise of options and issuance of common stock under our incentive plans.

As of December 31, 2011, we had options for 262,463 shares of common stock outstanding pursuant to our 2006 Incentive Stock Option Plan. Our 2009 Amended and Restated Equity Incentive Plan (the "2009 Plan") permits us to issue up to 4,000,000 shares of our common stock either upon exercise of stock options granted under such plan or through restricted stock awards under such plan. As of December 31, 2011, we had 1,139,118 shares remaining available for issuance pursuant to our 2009 Plan. No options have been issued under our 2009 Plan. If the holders of outstanding options exercise those options or our Compensation Committee determines to grant additional stock awards under our incentive plans, shareholders may experience dilution in the net tangible book value of our common stock. Further, the sale or availability for sale of the underlying shares in the marketplace could depress our stock price.

We do not expect to pay dividends in the foreseeable future.

We do not intend to declare dividends for the foreseeable future, as we anticipate that we will reinvest any future earnings in the development and growth of our business. Therefore, investors will not receive any funds unless they sell their common stock, and shareholders may be unable to sell their shares on favorable terms or at all. Investors cannot be assured of a positive return on investment or that they will not lose the entire amount of their investment in our common stock.

We may issue additional stock without shareholder consent.

Our Board of Directors has authority, without action or vote of the shareholders, to issue all or part of our authorized but unissued shares. Additional shares may be issued in connection with future financing, acquisitions, employee stock plans, or otherwise. Any such issuance will dilute the percentage ownership of existing shareholders. We are also currently authorized to issue up to 5,000,000 shares of preferred stock. The Board of Directors can issue preferred stock in one or more series and fix the terms of such stock without shareholder approval. Preferred stock may include the right to vote as a series on particular matters, preferences as to dividends and liquidation, conversion and redemption rights and sinking fund provisions. The issuance of preferred stock could adversely affect the rights of the holders of common stock and reduce the value of the common stock. In addition, specific rights granted to holders of preferred stock could discourage, delay or prevent a transaction involving a change in control of our company, even if doing so would benefit our shareholders, and could also discourage proxy contests and make it more difficult for you and other shareholders to elect directors of your choosing and to cause us to take other corporate actions you desire.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Leasehold Properties

As of December 31, 2011, our principal assets included approximately 168,843 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, 2011.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	196,771	48,510	337,045	88,711	533,815	137,221
Montana	10,961	3,709	62,422	26,632	73,383	30,341
New York	–	–	1,281	1,281	1,281	1,281
Total	207,732	52,219	400,748	116,624	608,479	168,843

Recent Acreage Acquisitions

In 2011, we acquired leasehold interests covering an aggregate of approximately 43,239 net mineral acres in our key prospect areas, for an average cost of $1,832 per net acre. These acquisitions consisted of an average of approximately 244 net mineral acres per transaction.

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.

Divestitures

In November 2009, we agreed to participate in the exploration and development of Slawson Exploration Company, Inc.'s ("Slawson") Anvil project in Roosevelt and Sheridan Counties, Montana and Williams County, North Dakota. In April 2011, we sold our interest in the Anvil project for $5.0 million. As of the date of sale, our cost basis in the Anvil project was $1.8 million. We sold our interest in the project along with 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 we retained our interest in that wellbore in connection with the divestiture. The proceeds from the sale were applied to reduce the capitalized costs of oil and gas properties.

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 2012 and 2016 and thereafter, are set forth below:

	Acres Expiring	
Year Ended	Gross	Net
December 31, 2012	45,503	17,677
December 31, 2013	75,521	23,765
December 31, 2014	76,231	23,371
December 31, 2015	73,160	20,925
December 31, 2016 and thereafter	27,255	17,998
Total	297,670	103,738

During 2011, we had leases expire in Montana, New York and North Dakota covering approximately 26,428 net acres, of which approximately 15,673 net acres were prospective for the Bakken and Three Forks Formations in Montana and North Dakota. The 2011 lease expirations carried a $9 million cost which was transferred to the costs subject to depletion. We believe that the expired acreage was not material to our capital deployed in these prospects. We do not consider the expiration of acreage during 2011 to be material.

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, with the exception of three defined drilling projects with Slawson.

As of December 31, 2011, we were participating in three defined drilling projects with Slawson covering an aggregate of approximately 17,400 net acres controlled by us. The Windsor project area includes approximately 2,700 net acres controlled by us, primarily located in Mountrail and surrounding counties of North Dakota. The South West Big Sky project includes approximately 3,900 total net acres controlled by us in Richland County, Montana. The Lambert project includes approximately 10,800 total net acres controlled by us in Richland and Dawson Counties, Montana.

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 crude oil and natural gas volumes during the year ended December 31, 2011, 2010 and 2009. As of December 31, 2011, we were selling crude oil and natural gas from a total of 664 gross (57.9 net) wells. As of December 31, 2010, we were selling crude oil and natural gas from a total of 311 gross (26.0 net) wells. As of December 31, 2009, we were selling crude oil and natural gas from a total of 179 gross (9.2 net) wells. All of the forgoing 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,		
	2011	2010	2009
Net Production:			
Crude Oil (Bbl)	1,791,979	849,845	274,328
Natural Gas (Mcf)	800,207	234,411	47,305
Barrel of Crude Oil Equivalent (BOE)	1,925,347	888,914	282,212
Average Sales Prices:			
Crude Oil (per Bbl)	$86.01	$68.27	$54.60
Effect of crude oil hedges on average price (per Bbl)	(7.48)	(0.55)	(2.28)
Crude Oil net of hedging (per Bbl)	78.53	67.72	52.32
Natural Gas and other liquids (per Mcf)	6.63	6.26	4.11
Realized price on a BOE basis including all realized derivative settlements	75.85	66.39	51.55
Average Production Costs:			
Barrel of Oil Equivalent (per BOE)	$6.77	$3.70	$2.68

Depletion of crude 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 2011, 2010 and 2009.

	Year Ended December 31,		
	2011	2010	2009
Depletion of crude oil and natural gas properties	$40,815,426	$16,884,563	$4,250,983

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, 2011, 2010 and 2009. No wells have been permitted or drilled on any of our Yates County, New York acreage. 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. As of December 31, 2011, we have had 100% success rate in our North Dakota and Montana Bakken and Three Forks wells.

22

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Crude oil	1	0.01	2	0.44	1	0.23
Natural gas	–	–	–	–	–	–
Non-productive	1	0.33	–	–	–	–
Development Wells:						
Crude oil	353	32.26	168	16.41	144	6.86
Natural gas	–	–	–	–	–	–
Non-productive	–	–	–	–	–	–
Total Productive Exploratory and Development Wells	354	32.27	170	16.85	145	7.09

The following table summarizes our cumulative gross and net productive crude oil wells by state at each of December 31, 2011, 2010 and 2009.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	642	54.40	300	23.90	170	8.17
Montana	22	3.53	11	2.13	9	1.02
Total	664	57.94	311	26.03	179	9.19

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, 2011.

Based on the results of our December 31, 2011 reserve analysis, our proved reserves increased approximately 198% during 2011 primarily as a result of increased 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 $300 million of capital expenditures for drilling activities and $80 million for acreage acquisitions during the year ended December 31, 2011, 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 2011. Our proved undeveloped reserves increased by approximately 234% during 2011 primarily as a result of drilling activity and our acquisitions of acreage. Based on our independent reservoir engineering firm's calculation of proved undeveloped reserves as of December 31, 2010, approximately 16% of our proved undeveloped reserves were converted to proved developed reserves during 2011. 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. We do not have any material amounts of proved undeveloped reserves that have remained undeveloped for five years or more.

At 2011 year end, approximately 31% of our Bakken and Three Forks prospective acreage was developed. In addition, at 2011 year end, we had approximately 17,290 net acres being drilled and completed and approximately 12,886 net acres held by production, for a total of approximately 82,395 net acres, or approximately 49% of our prospective Bakken and Three Forks position, either developed, under the bit or held by production. All of our proved reserves are located in North Dakota and Montana.

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 crude 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.

In December 2011, we hired an internal reserve engineer who is responsible for overseeing the preparation of our reserves estimates. Our internal reserve engineer possesses a B.S. in chemical and petroleum engineering from the University of Pittsburgh and has ten years of oil and gas experience on the reservoir side. He has worked 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, 2011, 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 crude 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 crude oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating crude 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 crude 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 crude 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 – Estimates of crude oil and natural gas reserves that we make may be inaccurate and our actual revenues may be lower than our financial projections."

Ryder Scott prepared our reserve report valuing our proved reserves at December 31, 2011. 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)

	Crude Oil (barrels)	Natural Gas (Mcf)	Total (BOE)(2)	Pre-Tax PV10% Value $M(3)
PDP Properties	13,308,105	7,779,168	14,604,633	$534,492
PDNP Properties	1,030,471	673,488	1,142,718	$17,084
PUD Properties	27,538,402	21,216,508	31,074,487	$549,757
Total Proved Properties:	41,876,978	29,669,164	46,821,838	$1,101,333

(1) The SEC Pricing Proved Reserves table above values crude oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2011 assuming constant realized prices of $90.17 per barrel of crude oil and $6.18 per Mcf of natural gas, using a BTU factor of 1.5 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 crude 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 crude 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 crude 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 crude 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 crude 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 tables 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%)	$1,101,333
Future income taxes, discounted at 10%	262,636
Standardized measure of discounted future net cash flows	$838,697

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 crude 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 crude oil and natural gas is not likely to average the pricing parameters used to calculate our proved reserves. As such, the crude 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

On August 23, 2010, plaintiff Donald Rensch filed a shareholder derivative complaint (the “Original Complaint”) in the United States District Court for the District of Minnesota against our company as nominal defendant, Michael L. Reger, Ryan R. Gilbertson, James R. Sankovitz and Chad D. Winter, James Randall Reger, James Russell Reger, Weldon W. Gilbertson, Douglas M. Polinsky, Joseph A. Geraci, II and Voyager Oil & Gas, Inc. (“Voyager”). The Original Complaint alleged breach of fiduciary duty of loyalty and usurping of corporate opportunities by Messrs. M. Reger, Gilbertson, Sankovitz and Winter; asserted allegations against Messrs. James Randall Reger, Weldon W. Gilbertson, James Russell Reger, Douglas M. Polinsky and Joseph A. Geraci, II of aiding and abetting our officers in breaching their fiduciary duties and usurping of corporate opportunities in connection with the formation, capitalization, and operation of Plains Energy (Voyager’s predecessor); and asserted a claim against Voyager for tortious interference with a prospective business relationship. The plaintiff sought injunctive relief and damages, including imposing on Voyager and all of its assets a constructive trust for our company’s benefit. On June 20, 2011, the District Court granted a motion to dismiss the lawsuit, and the complaint was dismissed without prejudice.

On July 20, 2011 plaintiff Donald Rensch filed an amended shareholder derivative complaint (the “Amended Complaint”) in the same court against our company as nominal defendant, Michael L. Reger, Ryan R. Gilbertson, James R. Sankovitz and Voyager. All other defendants from the Original Complaint were not included as defendants in the Amended Complaint. The Amended Complaint alleges breach of fiduciary duty of loyalty and usurping of corporate opportunities by Messrs. Reger, Gilbertson and Sankovitz in connection with the formation, capitalization, and operation of Plains Energy (Voyager’s predecessor), and also includes related aiding and abetting claims against Voyager and Messrs. Reger and Gilbertson. The plaintiff seeks unspecified equitable relief and damages. We believe that each of the above claims lacks merit and intend to strongly defend our company and each of our current and/or former officers and directors in connection with this lawsuit. A motion to dismiss the lawsuit in the United States

District Court for the District of Minnesota was filed on September 9, 2011. The motion was heard before the Court on December 20, 2011, but the Court has not yet issued a ruling on the motion.

In addition to the foregoing, 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, as of February 15, 2012 are as follows:

Name	Age	Positions
Michael L. Reger	35	Chairman, Chief Executive Officer and Director
Ryan R. Gilbertson	35	President
Thomas W. Stoelk	56	Chief Financial Officer
James R. Sankovitz	37	Chief Operating Officer

Michael L. Reger has served as our Chief Executive Officer and Chairman of the Board of Directors since March 2007. Mr. Reger has been primarily involved in the acquisition of crude oil, gas and mineral rights for his entire professional life and is a director of Reger Oil based in Billings, Montana. Mr. Reger holds a Bachelor of Arts in Finance and an MBA 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.

Ryan R. Gilbertson has served as our President since March 2010 and served as a Director of our company from March 2007 to August 2011. Mr. Gilbertson previously served as our Chief Financial Officer from March 2007 to March 2010. Mr. Gilbertson's last position prior to co-founding Northern was at Piper Jaffray in Minneapolis from March 2004 to August 2006. Prior to Piper Jaffray, Mr. Gilbertson was a portfolio manager at Telluride Asset Management, a multi-strategy hedge fund based in Wayzata, Minnesota. Mr. Gilbertson holds a BA from Gustavus Adolphus College in International Business/Finance.

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.

James R. Sankovitz has served as our Chief Operating Officer since March 2010, and previously served as our General Counsel from March 2008 until October 2011. Prior to joining our company, Mr. Sankovitz was a partner at the law firm Adams, Monahan & Sankovitz, LLP from November 2004 to March 2008, where he represented various public and private companies and individuals concerning state and federal securities laws, corporate finance matters, mergers and acquisitions, capital structuring, regulatory compliance and other business-related matters. Mr. Sankovitz has assisted clients as an attorney and consultant in pursuing capital-raising transactions (including private placements, mergers, tender offers, bond offerings, bridge financings and bank financings), structuring complex transactions, completing mergers, acquisitions and similar transactions, developing strategic business plans, exploring licensing opportunities, evaluating cash needs and resources, negotiating various agreements and addressing securities law compliance and general corporate matters.

PART II

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

Market Information

Our common stock commenced trading on the AMEX on March 26, 2008 under the symbol "NOG." The high and low sales prices for shares of common stock of our company for each quarter during 2010 and 2011 are set forth below.

	Sales Price	
	High	Low
Fiscal Year Ended December 31, 2011		
First Quarter	$33.98	$23.50
Second Quarter	27.25	16.63
Third Quarter	25.01	13.25
Fourth Quarter	27.70	16.50
Fiscal Year Ended December 31, 2010		
First Quarter	$16.23	$10.47
Second Quarter	18.00	11.72
Third Quarter	17.11	11.95
Fourth Quarter	28.43	16.98

The closing price for our common stock on the NYSE Amex Equities Market on February 15, 2012 was $23.43 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 56-month cumulative total shareholder returns since completion of our reverse merger on April 13, 2007 of Northern Oil and Gas, Inc., and the cumulative total returns of Standard & Poor's Composite 500 Index and the Amex Oil Index for the same period. This graph assumes $100 was invested in the stock or the Index on April 13, 2007 and also assumes the reinvestment of dividends. We have not included any graph for any period prior to April 13, 2007, because there was no active trading in our common stock prior to April 13, 2007 and, as such, data is not available for any period prior to such date.

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

	4/13/2007	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
Northern Oil and Gas, Inc. (NOG)	$100.00	$173.75	$65.00	$296.00	$680.25	$599.50
Standard & Poor's Composite 500 Index	100.00	104.82	66.04	83.52	96.10	98.13
Amex Oil Index	100.00	126.46	89.73	101.26	107.40	114.61

Holders

As of February 15, 2012, we had 63,481,852 shares of our common stock outstanding, held by approximately 389 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, 2011.

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publically Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)
Month #1				
October 1, 2011 to October 31, 2011	26,292	$19.39	-	150 million
Month #2				
November 1, 2011 to November 30, 2011	12,055	22.77	-	150 million
Month #3				
December 1, 2011 to December 31, 2011	12,047	24.64	-	150 million
Total	50,394	$21.45	-	150 million

(1) All shares purchased reflect shares surrendered by company employees 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 not made any repurchases under this program to date.

30

Item 6. Selected Financial Data

	Fiscal Years				
	2011	2010	2009	2008	2007
Statements of Income Information:					
Revenues					
Oil and Gas Sales	$159,439,508	$59,488,284	$15,171,824	$3,542,994	$–
(Loss) Gain on Settled Derivatives	(13,407,878)	(469,607)	(624,541)	778,885	–
Gain (Loss) on Mark-to-Market of Derivative Instruments	3,072,229	(14,545,477)	(363,414)	–	–
Other Revenue	285,234	85,900	37,630	–	–
Total Revenues	149,389,093	44,559,100	14,221,499	4,321,879	–
Operating Expenses					
Production Expenses	13,043,633	3,288,482	754,976	70,954	–
Production Taxes	14,300,720	5,477,975	1,300,373	203,182	–
General and Administrative Expense	13,624,892	7,204,442	3,686,330	2,091,289	4,509,743
Depletion Oil and Gas Properties	40,815,426	16,884,563	4,250,983	677,915	–
Depreciation and Amortization	298,137	176,595	91,794	67,060	3,446
Accretion of Discount on Asset Retirement Obligations	56,055	21,755	8,082	1,030	–
Total Expenses	82,138,863	33,053,812	10,092,538	3,111,430	4,513,189
Income (Loss) from Operations	67,250,230	11,505,288	4,128,961	1,210,449	(4,513,189)
Other Income	–	–	479,100	–	240
Interest Expense	(585,982)	(583,376)	(535,094)	(27,485)	–
Interest Income	567,452	472,912	191,985	286,736	205,337
Gain (Loss) on Available for Sale Securities	215,092	(58,524)	–	124,640	2,319
Other Income (Expense)	196,562	(168,988)	135,991	383,891	207,896
Income (Loss) Before Income Taxes	67,446,792	11,336,300	4,264,952	1,594,340	(4,305,293)
Income Tax Provision (Benefit)	26,835,300	4,419,000	1,466,000	(830,000)	–
Net Income (Loss)	$40,611,492	$6,917,300	$2,798,952	$2,424,340	$(4,305,293)
Net Income (Loss) Per Common Share – Basic	$0.66	$0.14	$0.08	$0.08	$(0.18)
Net Income (Loss) Per Common Share – Diluted	$0.65	$0.14	$0.08	$0.07	$(0.18)
Weighted Average Shares Outstanding – Basic	61,789,289	50,387,203	36,705,267	31,920,747	23,667,119

Weighted Average Shares Outstanding - Diluted	62,195,340	50,778,245	36,877,070	32,653,552	23,667,119
Balance Sheet Information:					
Total Assets	$725,593,919	$509,693,965	$135,594,968	$54,520,399	$18,131,464
Revolving Line of Credit	$69,900,000	–	–	–	–
Total Liabilities	$229,023,864	$74,334,483	$12,035,518	$4,991,336	$224,247
Shareholders' Equity	$497,797,055	$435,359,482	$123,559,450	$49,529,063	$17,907,217
Statement of Cashflow Information:					
Net cash provided by (used for) operating activities	$85,149,526	$73,307,220	$9,812,910	$2,506,492	$(491,509)
Net cash used for investing activities	$(300,867,801)	$(207,893,450)	$(71,848,701)	$(40,357,962)	$(5,078,758)
Net cash provided by financing activities	$69,887,161	$280,463,559	$67,488,447	$28,519,526	$14,832,992

Source of Our Revenues

We derive our revenues from the sale of crude oil, natural gas and natural gas liquids ("NGLs") produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, 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 crude oil and natural gas production. We expect our hedging 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 protects us from declining price movements. Our average realized price calculations (including all derivative settlements) include the effects of the settlement of all derivative contracts regardless of the accounting treatment.

Principal Components of Our Cost Structure

Production expenses. Production expenses are daily costs incurred to bring crude 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 workover expenses related to our crude oil and natural gas properties.

Production taxes. Production taxes are paid on produced crude 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 crude 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 crude oil and natural gas. 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.

Gain (Loss) on Mark-to-Market of Derivative Instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of crude 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.

Gain (Loss) on settled derivatives. We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of crude oil. This account activity represents our realized gains and losses on the settlement of these commodity derivative instruments.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our revolving credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize interest paid to the lenders under our revolving credit facility into our full cost pool. We include the amortization of deferred financing costs (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 record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Market Conditions

Prices for various quantities of crude oil and natural gas that we produce significantly impact our revenues and cash flows. Commodity prices have been volatile in recent years. The following table lists average NYMEX prices for crude oil and natural gas for the years ended December 31, 2011, 2010 and 2009. No similar published benchmark exists for NGL prices. The price uplift from the sale of other liquids is included in the natural gas price.

	Year Ended December 31,		
	2011	2010	2009
Average NYMEX prices(1)			
Crude Oil (per Bbl)	$95.11	$79.61	$62.09
Natural gas (per Mcf)	$4.03	$4.38	$4.16

(1) Based on average of daily closing prices.

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 2011 Results

During 2011, we achieved the following financial and operating results:

117% production growth compared to 2010;

198% proved reserve growth compared to 2010;

Participated in the completion of 354 gross (32.3 net) wells, with a 100% success rate in the Bakken and Three Forks plays;

Continued expansion of our activities in the Bakken Shale by growing production, proving up acreage and acquiring additional acreage;

Maintained a strong balance sheet by retaining a debt to capitalization ratio of 12%;

Entered into additional derivative contracts for 2012 and 2013;

Realized $85.1 million of cash flow from operating activities; and

Ended the year with stockholders' equity of $496.6 million.

Operationally, our 2011 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 31.1 million BOE, which is more than 16 times 2011 production. During 2011, production increased 117% to 1.9 million BOE as compared to 2010 production of 0.9 million BOE. The increase in 2011 production was driven by a 123% increase in producing net wells from 26.0 net wells at December 31, 2010 to 57.9 net wells at December 31, 2011.

Total revenues increased 235% in 2011 compared to 2010. This increase was due to higher production and a $3.1 million non-cash gain from mark-to-market of derivative instruments. Average realized prices on a BOE basis (including all realized derivative settlements) were 14% higher in 2011 compared to 2010. As discussed elsewhere in this report, significant changes in crude 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.

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

	Year Ended December 31,		
	2011	2010	2009
Net Production:			
Oil (Bbl)	1,791,979	849,845	274,328
Natural Gas (Mcf)	800,207	234,411	47,305
Net Sales:			
Oil Sales	$154,132,404	$58,020,694	$14,977,556
Natural Gas	5,307,104	1,467,590	194,268
Loss on Settled Derivatives	(13,407,878)	(469,607)	(624,541)
Gain (Loss) on Mark-to-Market of Derivative Instruments	3,072,229	(14,545,477)	(363,414)
Other Revenue	285,234	85,900	37,630
Total Revenues	149,389,093	44,559,100	14,221,499
Average Sales Prices:			
Oil (per Bbl)	$86.01	$68.27	$54.60
Effect of Loss on Settled Derivatives on Average Price (per Bbl)	(7.48)	(0.55)	(2.28)
Oil Net of Settled Derivatives (per Bbl)	78.53	67.72	52.32
Natural Gas and other liquids (per Mcf)	6.63	6.26	4.11
Realized price on a BOE basis including all realized derivative settlements	75.85	66.39	51.55
Operating Expenses:			
Production Expenses	$13,043,633	$3,288,482	$754,976
Production Taxes	14,300,720	5,477,975	1,300,373
General and Administrative Expense (Including Share Based Compensation)	13,624,892	7,204,442	3,686,330
Depletion of Oil and Gas Properties	40,815,426	16,884,563	4,250,983

Results of Operations for 2011, 2010 and 2009

Crude Oil, Natural Gas and NGL Sales, Production and Realized Price Calculations

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. In 2011, crude oil, natural gas and NGL sales increased 168% from 2010, driven primarily by a 117% increase in production and partially aided by a 14% increase in realized prices taking into account the effect of settled derivatives. In 2010, crude oil and natural gas sales increased 292% from 2009 due to a 29% increase in realized prices, and a 215% increase in production.

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 crude oil and natural gas sales from existing wells. For 2011, our production volumes increased 117% as compared to 2010. For 2010, our production volumes increased 215% as compared to 2009. The production primarily increased due to the addition of 32.3 and 16.8 net productive wells in 2011 and 2010, respectively. Our production for each of the last three years is set forth in the following table:

	Year Ended		
	2011	2010	2009
Production(1)			
Crude oil (Bbl)	1,791,979	849,845	274,328
Natural gas and NGL (Mcf)	800,207	234,411	47,305
Total (BOE)(2)	1,925,347	888,914	282,212
Average daily production(1)			
Crude oil (Bbl)	4,910	2,328	752
Natural gas and NGL (Mcf)	2,192	642	130
Total (BOE)(2)	5,275	2,435	773

(1) Represents volumes produced.

(2) 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 crude oil and natural gas, which is not necessarily indicative of the relationship of crude oil and natural gas prices.

We enter into derivative instruments to manage the price risk attributable to future crude oil production. For 2011, we incurred a loss on settled derivatives of $13,407,878, compared to $469,607 in 2010 and $624,541 in 2009. Our average realized price (including all derivative settlements) received during 2011 was $75.85 per BOE compared to $66.39 per BOE in 2010 and $51.55 per BOE in 2009. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives.

Mark-to-Market Derivative Gains and Losses

Mark-to-market derivative gains and losses were gains of $3,072,229 in 2011 compared to a $14,545,477 loss in 2010 and a $363,414 loss in 2009. Most of 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 unrealized gains and losses from 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, 2011, all of our derivative contracts are recorded at their fair value, which was a net liability of $11,937,971, a decrease of $4.2 million from the $16,167,976 net liability recorded as of December 31, 2010.

Production Expenses

Production expenses were $13,043,633 in 2011 compared to $3,288,482 in 2010 and $754,976 in 2009. We experience increases in operating expenses as we add new wells and maintain production from existing properties. On a per unit basis, production expenses per BOE increased from $3.70 per barrel sold in 2010 to $6.77 in 2011. On a per unit basis, production expenses per BOE increased from $2.68 per barrel sold in 2009 to $3.70 in 2010. These increases are related to higher operating costs primarily in our Williston Basin activities. The largest cost driver in our Williston Basin operations is the disposal of water. On an absolute dollar basis, our spending for production expenses for 2011 was 297% higher when compared to 2010 due to production levels increasing 117%, higher water hauling and disposal costs and workover expenses. On an absolute dollar basis, our spending for production expenses for 2010 was higher when compared to 2009 due to production levels increasing 215% and higher water hauling and disposal expenses.

Production Taxes

We pay production taxes based on realized crude oil and natural gas sales. These costs were $14,300,720 in 2011 compared to $5,477,975 in 2010 and $1,300,373 in 2009. Our production taxes were 9.0%, 9.2% and 8.6% in 2011, 2010 and 2009, respectively. The 2011 average production tax rate was lower than the 2010 average due to well additions that qualified for reduced rates/or tax exemptions during 2011. 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 2010 average production tax rate was higher than the 2009 average due to the increased weighting of North Dakota oil revenues in 2010. 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 $13,624,892 for 2011 compared to $7,204,442 for 2010 and $3,686,330 in 2009. The 2011 increase of $6.4 million when compared to 2010 is due to higher base salaries and benefits ($0.9 million), increased share based compensation expense ($2.6 million), higher legal and professional expenses ($1.3 million), increased travel expenses ($0.5 million) and higher office and other administrative expenses due to the addition of adding more employees ($1.1 million). As a result of our growth, the number of employees increased by 122% in 2011 as compared to 2010 to provide additional staffing in the legal, finance and land departments. The 2010 increase of $3.5 million when compared to 2009 is due to higher base salaries and benefits ($0.4 million), increased share based compensation expense ($2.3 million), increased travel expenses ($0.4 million) and higher office and other administrative expenses ($0.4 million). Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our growth. Share based compensation expense represents the amortization of restricted stock grants granted to our employees and directors as part of compensation as well as fully vested share grants to employees and directors throughout the year.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization (“DD&A”) was $41,169,618 in 2011 compared to $17,082,913 in 2010 and $4,350,859 in 2009. Depletion expense, the largest component of DD&A, was $21.20 per BOE in 2011 compared to $18.99 per BOE in 2010 and $15.06 per BOE in 2009. Our depletion expense is based on the capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs which are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves determined by independent petroleum engineers. 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 increase in depletion expense for 2011 compared to 2010 was driven by a 117% increase in production. Additionally, depletion rates rose in 2011 due to an increase in our future development cost estimates to reflect the changes in well completion methodologies (e.g. more stimulation costs per well due to longer lateral extensions). 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 increase in depletion expense for 2010 compared to 2009 was driven by a 215% increase in production. Depreciation, amortization and accretion was $354,192 in 2011 compared to $198,350 in 2010 and $99,876 in 2009. The following table summarizes DD&A expense per BOE for 2011, 2010 and 2009:

	Year Ended December 31,				Year Ended December 31,			
	2011	2010	Change	Change	2010	2009	Change	Change
Depletion	$21.20	$18.99	$2.21	12 %	$18.99	$15.06	$3.93	26 %

Depreciation, amortization, and accretion	0.18	0.23	(0.05)	(22%)	0.23	0.35	(0.12)	(34)%
Total DD&A expense	$21.38	$19.22	$2.16	11%	$19.22	$15.42	$3.80	25%

Interest Expense

Interest expense was $585,982 for 2011 compared to $583,376 in 2010. Interest expense was $583,376 for 2010 compared to $535,094 in 2009. The increases in interest expense between periods were primarily due to different weighted average debt amounts outstanding between years.

Interest Income

Interest income was $567,452 for 2011 compared to $472,912 in 2010. Interest income for 2011 increased $94,540 as compared to 2010 because of higher levels of cash and short term investments. The higher amount of cash and short term investments resulted from the sale of common stock in November 2010. Interest income was $472,912 for 2010 compared to $191,985 in 2009. Interest income for 2010 increased $280,927 as compared to 2009 due to higher levels of cash and short term investments that resulted from the sale of common stock.

Income Tax Provision

The provision for income taxes was $26,835,300 in 2011 compared to $4,419,000 in 2010 and $1,466,000 in 2009. The effective tax rate in 2011 was 39.8% compared to an effective tax rate of 39.0% in 2010. Due to higher pre-tax income levels, the Company increased its 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 of 3.6% and 4.6% in 2011 and 2010, respectively. The 2010 effective tax rate was 39.0% compared to an effective tax rate in 2009 of 34.4%. The effective tax rate was different than the statutory rate of 34% primarily due to state tax rates of 4.6% and 6.9% in 2010 and 2009, respectively. We expect our effective tax rate to be approximately 38–39% for 2012.

Net Income

Net income was $40,611,492 in 2011 compared to $6,917,300 in 2010 and $2,798,952 in 2009. The increases in net income were driven by higher production levels and higher average sales prices received during each successive period. Partially offsetting the higher oil and gas revenues were increased production expense, production taxes, general and administrative expenses and depletion expenses in each of the respective periods as described above. Higher net income levels increased diluted net income per common share to $0.65, $0.14 and $0.08 in 2011, 2010 and 2009, respectively.

Non-GAAP Financial Measures

Pre-tax PV10% value 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 standardized financial measure. Pre-tax PV10% value is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. As of December 31, 2011, our discounted future income taxes were $262.6 million and our standardized measure of after-tax discounted future net cash flows was $838.7 million. We believe pre-tax PV10% value is a useful measure for investors for evaluating the relative monetary significance of our crude oil and natural gas properties. We further believe investors may utilize pre-tax PV10% value 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 crude oil and natural gas properties and acquisitions. However, pre-tax PV10% value is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% value and the standardized measure of discounted future net cash flows do not purport to present the fair value of our crude oil and natural gas reserves.

Our non-GAAP net income, which excludes unrealized mark-to-market derivative gains and losses net of tax, for the year ended December 31, 2011, was $38,762,263 (representing approximately $0.62 per diluted share) as compared to our non-GAAP net income, which excludes unrealized mark-to-market hedging gains and losses net of tax of $15,813,777 (representing approximately $0.31 per diluted share) for the year ended December 31, 2010. The increase in non-GAAP net income is primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices in 2011 compared to 2010.

We define Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion and amortization, (iv) accretion of discount on asset retirement obligations, (v) gain (loss) on mark-to-market of derivative instruments and (vii) non-cash expenses relating to share based payments recognized under ASC Topic 718. Adjusted EBITDA for the year ended December 31, 2011 was $112,294,487, compared to Adjusted EBITDA of $47,114,199 for the year ended December 31, 2010. The increase in Adjusted EBITDA is primarily due to our continued addition of crude oil and natural gas production from new wells and higher realized commodity prices in 2011 compared to 2010.

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.

The non-GAAP financial information is presented using consistent methodology from year to year. 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.

Net income excluding unrealized mark-to-market derivative gains and losses 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 Non-GAAP Net Income Excluding
Unrealized Mark-to-Market Derivative Gains and Losses

	Year Ended December 31,		
	2011	2010	2009
Net Income	$40,611,492	$6,917,300	$2,798,952
(Gain) Loss on Mark-to-Market of Derivative Instruments	(3,072,229)	14,545,477	363,414
Tax Impact	1,223,000	(5,649,000)	(140,000)
Net Income without the Effect of Certain Items	$38,762,263	$15,813,777	$3,022,366
Net Income Per Common Share - Basic	$0.63	$0.31	$0.08
Net Income Per Common Share - Diluted	$0.62	$0.31	$0.08
Weighted Average Shares Outstanding – Basic	61,789,289	50,387,203	36,705,267
Weighted Average Shares Outstanding - Diluted	62,195,340	50,778,245	36,877,070
Net Income Per Common Share - Basic	$0.66	$0.14	$0.08
Change due to Mark-to-Market of Derivative Instruments	(0.05)	0.28	-
Change due to Tax Impact	0.02	(0.11)	-
Net Income without Effect of Certain Items Per Common Share - Basic	$0.63	$0.31	$0.08
Net Income Per Common Share - Diluted	$0.65	$0.14	$0.08
Change due to Mark-to-Market of Derivative Instruments	(0.05)	0.28	-
Change due to Tax Impact	0.02	(0.11)	-
Net Income without Effect of Certain Items Per Common Share - Diluted	$0.62	$0.31	$0.08

Northern Oil and Gas, Inc.
Reconciliation of Adjusted EBITDA

	Year Ended December 31,		
	2011	2010	2009
Net Income	$40,611,492	$6,917,300	$2,798,952
Add Back:			
Income Tax Provision	26,835,300	4,419,000	1,466,000
Depreciation, Depletion, Amortization and Accretion	41,169,618	17,082,913	4,350,859
Share Based Compensation	6,164,324	3,566,133	1,233,507
(Gain) Loss on Mark-to-Market Derivative Instruments	(3,072,229)	14,545,477	363,414
Interest Expense	585,982	583,376	535,094
Adjusted EBITDA	$112,294,487	$47,114,199	$10,747,826

2012 Operation Plan

We expect to spend $325 million in 2012 with associated drilling capital expenditures. The 2012 wells are expected to target both the Bakken and Three Forks formations. Drilling capital expenditures are expected to increase in 2012 due to the continued success of longer laterals and additional fracture stimulation stages. We currently expect to drill wells during 2012 at an average completed cost of $6.5 million to $7.5 million per well, which represents a 10% to 15% increase in drilling costs for 2012 compared to 2011. Based on evolving conditions in the field, we expect to continue to evaluate further strategic acreage acquisitions during 2012. Additionally, we expect to spend approximately $60 million to $80 million on acreage capital expenditures during 2012. Northern has the ability to adjust capital expenditures by reducing the number of projects we elect to participate in. We currently expect to fund all 2012 commitments using a combination of cash-on-hand, cash flow generated by operations, bank borrowings and potential debt financings.

Our future financial results will depend primarily on: (i) the ability to continue to source and screen potential projects; (ii) the ability to discover commercial quantities of crude oil and natural gas; (iii) the market price for crude oil and natural gas; and (iv) the ability to fully implement our exploration and development program, which is dependent on the availability of capital resources. There can be no assurance that we will be successful in any of these respects, that the prices of crude oil and natural gas prevailing at the time of production will be at a level allowing for profitable production, or that we will be able to obtain additional funding if necessary.

As of February 15, 2012, we controlled the rights to mineral leases covering approximately 170,000 net acres prospective for the Bakken and Three Forks. In the first quarter of 2012 through February 15, 2012, we acquired approximately 2,900 net acres at an average price of $2,029 per acre. Our goal is to continue to explore for and develop hydrocarbons within the mineral leases we control as well as continue to expand our acreage position should opportunities present themselves. To accomplish our objectives we must achieve the following:

- Continue to develop our substantial inventory of high quality core Bakken acreage with results consistent with those to-date;
- Retain and attract talented personnel;
- Continue to be a low-cost producer of hydrocarbons;
- Actively manage our cost structure and focus on accretive acquisitions; and
- Continue to manage our financial obligations to access the appropriate capital needed to develop our position of primarily undrilled acreage.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a credit facility and access to the debt and equity capital markets. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In the future, we anticipate we will be able to provide the necessary liquidity by the revenues generated from the sales of our crude oil and natural gas reserves in our existing properties, credit facility borrowings and potential equity or debt issuances. However there is no guarantee the capital markets will be available to us on favorable terms or at all.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance, crude oil and natural gas prices, the value of our reserves, the state of the worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate and, in particular, with respect to borrowings, the level of our working capital or outstanding debt and credit ratings by rating agencies.

Overview

At December 31, 2011, our debt to total capitalization ratio was 12%, we had $69.9 million of debt outstanding, $496.6 million of stockholders' equity, and $6.3 million of cash on hand. At December 31, 2010, we had no debt, $435.4 million of stockholders' equity, $152.1 million of cash on hand and $39.7 million in short-term investments. In 2011, we generated $85.1 million of cash provided by operating activities, an increase of $11.8 million from 2010. Cash provided by operating activities increased primarily due to increased investment in oil and gas properties (32.3 net wells added in 2011), higher crude oil production volumes and higher average sales prices for both crude oil and natural gas in 2011. These positive factors were partially offset by increased production expenses, production taxes and general and administrative expenses during 2011 as compared to 2010. Cash flows from operating activities and advances under our revolving credit facility were used to partially fund approximately $300 million of drilling and development expenditures and $80 million of acreage acquisition expenditures in 2011.

Cash Flow

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 24 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 credit facility. As of December 31, 2011, we had entered into derivative agreements covering 1.4 million barrels for 2012 and 0.9 million barrels for 2013. 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, 2011, 2010 and 2009 are presented below:

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Net cash provided by operating activities	$ 85,150	$ 73,307	$ 9,813
Net cash used in investing activities	(300,868)	(207,894)	(71,849)
Net cash provided by financing activities	69,887	280,464	67,489
Net change in cash	$ (145,831)	$ 145,877	$ 5,453

Cash flows provided by operating activities

Net cash provided by operating activities was $85.1 million, $73.3 million and $9.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2011 as compared to 2010 was primarily the result of an increase in crude oil and natural gas production of 117%. In addition, at December 31, 2010, we had a working capital surplus of $173.4 million which was primarily attributable to higher cash and short-term investments balances as a result of the proceeds from the sale of common stock. Cash flows provided by operating activities during the year ended December 31, 2010 increased compared to 2009 primarily as a result of an increase in crude oil and natural gas production of 215%.

Cash flows used in investing activities

We had cash flows used in investing activities of $300.9 million, $207.9 million and $71.8 million during the years ended December 31, 2011, 2010 and 2009, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. The increase in cash used in investing activities for the year ended December 31, 2011 compared to 2010 of $93.0 million was attributable to our acquisitions of properties in the Williston Basin, as well as increased levels of development of our properties. During 2011, we increased our 2011 net well count as compared to our 2010 net well count by 123%. In 2011, we added 32.3 net wells to reach 57.9 net wells at year end. As a result of the increased development activities, the Company sold $39.7 million of short-term investments to fund the drilling, development and acquisition costs. The $136.0 million increase in cash used in investing activities for the year ended December 31, 2010 compared to December 31, 2009 was attributable to drilling, development and acquisition costs. During 2010, we increased our 2010 net well count as compared to our 2009 net well count by 183%. In 2010, we added 16.8 net wells to reach 26.0 net wells at the end of 2010. Also, in 2010 we increased our short-term investments by $14.8 million as we temporarily re-invested proceeds from the sale of common stock.

Cash flows provided by financing activities

Net cash provided by financing activities was $69.9 million, $280.5 million and $67.5 million for the years ended December 31, 2011, 2010 and 2009, respectively. For the year ended December 31, 2011, we received $69.9 million in net advances under our revolving credit facility that were used to fund drilling, development and acquisition costs. For the years ended December 31, 2010 and 2009, cash increased through financing activities was primarily provided by net proceeds from the sale of common stock.

Revolving Credit Facility

As of December 31, 2011, we maintained a $500 million revolving credit facility that is secured by substantially all of our assets with a maturity of May 26, 2014. We had $69.9 million of borrowings under this credit facility at December 31, 2011. At December 31, 2011, we had a borrowing base of $150 million, subject to a $120 million aggregate maximum credit amount that provided $50.1 million of additional borrowing capacity under this facility. For additional information, see Note 5 in our notes to the financial statements.

On February 28, 2012, we entered into an amended and restated revolving credit facility, which replaced our previous revolving credit facility. The new facility, secured by substantially all of our assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At closing, the facility amount was $750 million and provided for a $250 million borrowing base. The new credit facility provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. The new bank group is comprised of a group of commercial banks, with no single bank holding more than 25% of the total facility. As of February 28, 2012, the outstanding balance under the credit facility was $147.5 million leaving $102.5 million of borrowing capacity available under the facility. The loan matures on January 1, 2017. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.75% to 1.75% or LIBOR borrowings at the Adjusted LIBOR Rate (as defined) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. 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 0.375% to 0.50%. At closing, the commitment fee was 0.50% and the interest rate margin was 2.25% on our LIBOR loans and 1.25% on our base rate loans. The facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain types of investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0, a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0 and a ratio of EBITDAX to interest expense of no less than 3.0 to 1.0. We were in compliance with our covenants under the credit facility at December 31, 2011.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of crude oil and natural gas properties and payment of interest on outstanding indebtedness. During 2011, approximately $300 million of capital was incurred on drilling projects. Also in 2011, approximately $80 million was expended on acreage acquisitions located in the Williston Basin. Our 2011 capital program was funded by cash on hand, net cash flow from operations and borrowings under our credit facility. Our capital expenditure budget for 2012 is currently set at $325 million, excluding acquisitions. Development and acquisition activities are highly discretionary, and, for the near term, we expect such activities to be maintained at levels equal to 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 or equity 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. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for crude oil and natural gas, actions of competitors, disruptions or interruptions of our production and unforeseen hazards such as weather conditions, acts of war or terrorists acts and the government or military response, and other operating and economic considerations.

Satisfaction of Our Cash Obligations for the Next 12 Months

With the addition of our amended and restated credit facility in February 2012 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 equity or debt 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.

Though we achieved profitability in 2008 and remained profitable throughout 2009, 2010 and 2011, our prospects must be considered in light of the risks, expenses and difficulties frequently encountered by companies in their early stage of operations, particularly companies in the crude oil and natural gas exploration industry. Such risks include, but are not limited to, an evolving and unpredictable business model and the management of growth. To address these risks we must, among other things, implement and successfully execute our business strategy, continue to develop and upgrade our technology, respond to competitive developments, and attract, retain and motivate qualified personnel. There can be no assurance that we will be successful in addressing such risks, and the failure to do so can have a material adverse effect on our business prospects, financial condition and results of operations.

Effects of Inflation and Pricing

The crude oil and natural gas industry is very cyclical and the demand for goods and services of crude 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 crude 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 crude oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of crude 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 crude oil and natural gas could result in increases in the costs of materials, services and personnel.

43

Contractual Obligations and Commitments

The following table summarizes our obligations and commitments at December 31, 2011 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

	Payment due by Period				
Contractual Obligations	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
Office Lease(1)	$230,000	$652,000	$-	$-	$882,000
Automobile Leases(2)	63,000	48,000	-	-	111,000
Derivative Liability(3)	9,363,000	2,575,000	-	-	11,938,000
Long Term Debt(4)	-	69,900,000	-	-	69,900,000
Cash Interest Expense on Debt(5)	1,922,000	2,723,000	-	-	4,645,000
Total	$11,578,000	$75,898,000	$-	$-	$87,476,000

(1) Office lease through 2015
(2) Automobile leases for certain executives through 2014
(3) Swap Contracts and costless collars (see Note 15 to financial statements)
(4) Revolving Credit Facility (see Note 5 to financial statements)
(5) Cash interest on Revolving Credit Facility is estimated assuming no principal repayment until the due date

Product Research and Development

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

Expected Purchase or Sale of Any Significant Equipment

We do not anticipate the purchase or sale of any plant or significant equipment as such items are not required by us at this time or anticipated to be needed in the next twelve months.

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 crude oil and natural gas reserves, future development costs, estimates relating to certain crude oil and natural gas revenues and expenses and fair value of derivative instruments are the most critical to our financial statements.

Crude Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our crude oil and natural gas properties are highly dependent on the estimates of the proved crude oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of crude 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 crude 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 crude oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated crude 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 crude 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 crude 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.

Crude Oil and Natural Gas Properties

The method of accounting we use to account for our crude 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 crude 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 crude 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 crude oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of crude 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 crude 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, 2011, our average depletion expense per unit of production was $21.20 per BOE. A 10% decrease in our estimated net proved reserves at December 31, 2011 would result in a $0.84 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 crude oil and natural gas prices) of the estimated future net cash flows from our proved crude 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 crude oil and natural gas properties. The risk that we will be required to write down the carrying value of our crude oil and natural gas properties increases when crude 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 crude oil and natural gas properties cannot be reversed at a later date. The risk that we will experience a ceiling test writedown increases when crude oil and natural gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves. As of December 31, 2011 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.

Revenue Recognition

We derive revenue primarily from the sale of the crude 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 crude 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, 2011, 2010, 2009, and 2008, our 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.

In general, settlements for hydrocarbon sales occur around two months after the end of the month in which the crude 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 Instruments and Hedging Activities

We use derivative instruments from time to time to manage market risks resulting from fluctuations in the prices of crude 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 crude 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 crude oil at a future date.

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 in addition, 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 unrealized gains or losses are recorded to gain (loss) on mark-to-market of derivative instruments on the statement of income rather than as a component of accumulated other comprehensive income (loss) or other income (expense). See Note 15 for a description of the derivative contracts which the Company executed during 2011 and 2010.

Prior to November 1, 2009, at the inception of a derivative contract, we designated the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we 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. We historically measured hedge effectiveness on a quarterly basis and hedge accounting would be discontinued prospectively if it determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses deferred in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If we determine that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative are 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, depending on whether a derivative was designated as part of a hedge transaction and, if it was, depending on the type of hedge transaction. Our derivatives historically consisted primarily of cash flow hedge transactions in which we were 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.

New Accounting Pronouncements

Presentation of Comprehensive Income

In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05). The guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The standard will allow us the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued Comprehensive Income (Topic 220) — Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU No. 2011-12). The FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The standard, except for the portion that was indefinitely deferred, is effective for us on January 1, 2012, and must be applied retrospectively. We are evaluating the effects of this standard on disclosure, but it will not impact our results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs

In May 2011, the FASB issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU No. 2011-04). The standard generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the standard includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This standard is effective for us on January 1, 2012. The standard will require additional disclosures, but it will not impact our results of operations, financial position or cash flows.

Balance Sheet Offsetting

In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which updates the Codification to require 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 updates to the disclosure requirements of the Codification do not affect the presentation of amounts in the balance sheet, and are effective for annual reporting periods beginning on or after

January 1, 2013, and interim periods within those periods. The Company does not expect the implementation of this disclosure guidance to have a material impact on its financial statements.

Recent Accounting Pronouncements Not Yet Adopted

For a description of the accounting standards that we adopted in 2011, see Notes to Financial Statements—Note 2. Significant Accounting Policies.

Various accounting standards and interpretations were issued in 2011 with effective dates subsequent to December 31, 2011. We have evaluated the recently issued accounting pronouncements that are effective in 2012 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 2012 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 crude oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for crude 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 2011 generally would have increased or decreased along with any increases or decreases in crude oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling crude oil that also increase and decrease along with crude oil prices.

We have previously entered into derivative contracts to achieve a more predictable cash flow by reducing our exposure to crude oil and natural gas 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 in addition, 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 unrealized gains or losses are recorded to gain (loss) on mark-to-market of derivative instruments on the statement of income rather than as a component of other comprehensive income (loss) or other income (expense).

The following table reflects the weighted average price of open commodity swap contracts as of December 31, 2011, by year with associated volumes.

Weighted Average Price
Of Open Commodity Swap Contracts

Year	Volumes (Bbl)	Weighted Average Price
2012	1,015,000	$90.87

Subsequent to December 31, 2011, we had entered into an additional commodity swap contract. The crude oil swap contract is for 38,942 barrels of crude oil with a settlement period in January 2012. The price on the contract is fixed at $101.00 per barrel. In addition to the open commodity swap contracts we have entered into costless collars. The costless collars are used to establish floor and ceiling prices on anticipated crude oil and natural gas production. There were no premiums paid or received by us related to the costless collar agreements. The following table reflects the weighted average price of open costless collar contracts as of December 31, 2011, by year with associated volumes.

Weighted Average Price
Of Open Costless Collar Contracts

Year	Volumes (Bbl)	Weighted Average Price
2012	413,092	$88.28-$100.67
2013	910,309	$85.82-$ 98.90

As of February 16, 2012, we had entered into three additional costless collar contracts. The crude oil collars included 1,358,706 barrels of crude oil with an average floor of $91.78 and an average ceiling of $107.95. The settlement periods are between February 2012 and December 2013.

Interest Rate Risk

We had $69.9 million in outstanding borrowings at an average rate of 2.78% under our revolving credit facility as of December 31, 2011. We have the option to designate the reference rate of interest for each specific borrowing under the 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 2.5% to 3.25% 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 2% to 2.5%, 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 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 credit facility.

Our 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 the floating-rate debt outstanding at December 31, 2011 would cost us approximately $0.7 million 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, 2011, 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, 2011.

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, 2011, 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 & 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, 2011. 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.

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, 2011.

The effectiveness of our Company's internal control over financial reporting as of December 31, 2011, 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, 2011, based on criteria established in Internal Control — Integrated Framework 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, 2011, based on the criteria established in Internal Control — Integrated Framework 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, 2011 of the Company and our report dated February 29, 2012 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 29, 2012

Item 9B. Other Information

None.

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 2012 (the "Proxy Statement"), which we intend to file with the SEC pursuant to Regulation 14A within 120 days after December 31, 2011. 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 Amex Equity Market.

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, 2011:

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	262,463	$ 5.18	–
2009 Amended and Restated Equity Incentive Plan	–	–	1,139,118
Equity compensation plans not approved by security holders	–	–	–
Total	262,463	$ 5.18	1,139,118

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.	Filed herewith
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	*	Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and Ryan R. Gilbertson, dated January 30, 2009	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the SEC on February 2, 2009 (File No. 001-33999)
10.4	*	Amendment No. 1 to Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and Ryan R. Gilbertson, dated	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the SEC on March 25, 2010 (File No. 001-33999)

		March 25, 2010	
10.5	*	Amendment No. 2 to Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and Ryan R. Gilbertson, dated January 14, 2011	Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 10-K filed with the SEC on March 4, 2011 (File No. 001-33999)
10.6	*	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 for the 2011 Annual Meeting of Shareholders filed with the SEC on May 2, 2011 (File No. 001-33999)
10.7	*	Form of Promissory Note issued to Michael L. Reger and Ryan R. Gilbertson	Incorporated by reference to Exhibit 10.18 to the Registrant's Current Report on Form 10-K filed with the SEC on March 8, 2010
10.8	*	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
10.9	*	Form of Restricted Stock Agreement under the Northern Oil and Gas, Inc. Amended and Restated 2009 Equity Incentive Plan (for grants after June 8, 2011)	Filed herewith
10.10	*	Employment Agreement by and between Northern Oil and Gas, Inc. and Chad D. Winter, dated March 25, 2010	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on March 25, 2010
10.11	*	Amended and Restated Employment Agreement by and between Northern Oil and Gas, Inc. and Chad D. Winter, 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
10.12	*	Employment Agreement by and between Northern Oil and Gas, Inc. and James R. Sankovitz, dated March 25, 2010	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on March 25, 2010
10.13	*	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
10.14		Second Amended and Restated Credit Agreement dated as of August 8, 2011 among Northern Oil and Gas, Inc., as Borrower, Macquarie Bank Limited, as Administrative Agent, and the Lenders party thereto	Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 12, 2011
23.1		Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP	Filed herewith
23.2		Consent of Independent Registered Public Accounting Firm Mantyla McReynolds LLC	Filed herewith
23.3		Consent of Ryder Scott Company, LP	Filed herewith
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	Filed herewith

	U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
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: February 29, 2012	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 wherewith, 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	February 29, 2012
/s/ Thomas W. Stoelk Thomas W. Stoelk	Chief Financial Officer, Principal Financial Officer, Principal Accounting Officer	February 29, 2012
/s/ Loren J. O'Toole Loren J. O'Toole	Director	February 29, 2012
/s/ Richard Weber Richard Weber	Director	February 29, 2012
/s/ Jack King Jack King	Director	February 29, 2012
/s/ Robert Grabb Robert Grabb	Director	February 29, 2012

/s/ Lisa Bromiley Meier Lisa Bromiley Meier	Director	February 29, 2012
/s/ Delos Cy Jamison Delos Cy Jamison	Director	February 29, 2012

NORTHERN OIL AND GAS, INC.

INDEX TO FINANCIAL STATEMENTS

	Page
Report of Deloitte & Touche LLP, Independent Registered Public Accounting Firm	F-2
Report of Mantyla McReynolds LLC, Independent Registered Public Accounting Firm	F-3
Balance Sheets as of December 31, 2011 and 2010	F-4
Statements of Income for the Years Ended December 31, 2011, December 31, 2010 and December 31, 2009	F-5
Statements of Cash Flows for the Years Ended December 31, 2011, December 31, 2010 and December 31, 2009	F-6
Statements of Stockholders' Equity for the Years Ended December 31, 2011, December 31, 2010 and December 31, 2009	F-7
Notes to the Financial Statements	F-8

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 sheet of Northern Oil and Gas, Inc. (the "Company") as of December 31, 2011 and the related statements of income, stockholders' equity, and cash flows for the year then ended. 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 audit. The financial statements of the Company for the years ended December 31, 2010 and December 31, 2009 were audited by other auditors whose reports, dated March 4, 2011 and March 8, 2010, expressed an unqualified opinion on those statements.

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 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 audit provides a reasonable basis for our opinion.

In our opinion, such 2011 financial statements referred to above present fairly, in all material respects, the financial position of Northern Oil and Gas, Inc. as of December 31, 2011, and the results of its operations and its cash flows for the year then ended 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, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 29, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 29, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying balance sheet of Northern Oil and Gas, Inc. (the Company) as of December 31, 2010, and the related statements of operations, stockholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2010. 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, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2010, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

/s/ Mantyla McReynolds LLC

Mantyla McReynolds LLC
Salt Lake City, Utah
March 4, 2011

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31, 2011	December 31, 2010
CURRENT ASSETS		
Cash and Cash Equivalents	$6,279,587	$152,110,701
Trade Receivables	51,418,830	22,033,647
Advances to Operators	17,530,474	13,225,650
Prepaid Expenses	486,421	345,695
Other Current Assets	317,460	475,967
Short - Term Investments	-	39,726,700
Deferred Tax Asset	4,472,000	5,100,000
Total Current Assets	80,504,772	233,018,360
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	566,195,321	158,846,475
Unproved	137,784,903	136,135,163
Other Property and Equipment	2,988,641	2,479,199
Total Property and Equipment	706,968,865	297,460,837
Less - Accumulated Depreciation and Depletion	63,265,919	22,152,356
Total Property and Equipment, Net	643,702,946	275,308,481
DEBT ISSUANCE COSTS	1,386,201	1,367,124
TOTAL ASSETS	$725,593,919	$509,693,965
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$110,133,286	$48,500,204
Accrued Expenses	131,012	2,829
Derivative Liability	9,363,068	11,145,319
Other Liabilities	33,229	18,574
Total Current Liabilities	119,660,595	59,666,926
LONG-TERM LIABILITIES		
Revolving Credit Facility	69,900,000	-
Derivative Liability	2,574,903	5,022,657
Other Noncurrent Liabilities	959,366	477,900
Deferred Tax Liability	35,929,000	9,167,000
Total Long-Term Liabilities	109,363,269	14,667,557
Total Liabilities	229,023,864	74,334,483
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value$.001; 5,000,000 Authorized,		
No Shares Outstanding	-	-

Common Stock, Par Value $.001; 95,000,000 Authorized, (12/31/2011 - 63,330,421 Shares Outstanding and 12/31/2010 – 62,129,424 Shares Outstanding)	63,330	62,129
Additional Paid-In Capital	448,198,350	428,484,092
Retained Earnings	48,370,684	7,759,192
Accumulated Other Comprehensive Loss	(62,309)	(945,931)
Total Stockholders' Equity	496,570,055	435,359,482
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$725,593,919	$509,693,965

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

NORTHERN OIL AND GAS, INC.
STATEMENT OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	Year Ended December 31,		
	2011	2010	2009
REVENUES			
Oil and Gas Sales	$ 159,439,508	$ 59,488,284	$ 15,171,824
Loss on Settled Derivatives	(13,407,878)	(469,607)	(624,541)
Gain (Loss) on Mark-to-Market of Derivative Instruments	3,072,229	(14,545,477)	(363,414)
Other Revenue	285,234	85,900	37,630
	149,389,093	44,559,100	14,221,499
OPERATING EXPENSES			
Production Expenses	13,043,633	3,288,482	754,976
Production Taxes	14,300,720	5,477,975	1,300,373
General and Administrative Expense	13,624,892	7,204,442	3,686,330
Depletion of Oil and Gas Properties	40,815,426	16,884,563	4,250,983
Depreciation and Amortization	298,137	176,595	91,794
Accretion of Discount on Asset Retirement Obligations	56,055	21,755	8,082
Total Expenses	82,138,863	33,053,812	10,092,538
INCOME FROM OPERATIONS	67,250,230	11,505,288	4,128,961
OTHER INCOME (EXPENSE)			
Other Income	-	-	479,100
Interest Expense	(585,982)	(583,376)	(535,094)
Interest Income	567,452	472,912	191,985
Gain (Loss) on Available for Sale Securities	215,092	(58,524)	-
Total Other Income (Expense)	196,562	(168,988)	135,991
INCOME BEFORE INCOME TAXES	67,446,792	11,336,300	4,264,952
INCOME TAX PROVISION	26,835,300	4,419,000	1,466,000
NET INCOME	$ 40,611,492	$ 6,917,300	$ 2,798,952
Net Income Per Common Share - Basic	$ 0.66	$ 0.14	$ 0.08
Net Income Per Common Share - Diluted	$ 0.65	$ 0.14	$ 0.08
Weighted Average Shares Outstanding – Basic	61,789,289	50,387,203	36,705,267
	62,195,340	50,778,245	36,877,070

Weighted Average Shares Outstanding -
Diluted

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

NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	Year Ended December 31, 2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$40,611,492	$6,917,300	$2,798,952
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Depletion of Oil and Gas Properties	40,815,426	16,884,563	4,250,983
Depreciation and Amortization	298,137	176,595	91,794
Amortization of Debt Issuance Costs	430,760	455,302	459,343
Accretion of Discount on Asset Retirement Obligations	56,055	21,755	8,082
Deferred Income Taxes	26,833,000	4,419,000	1,466,000
Net (Gain) Loss on Sale of Available for Sale Securities	(215,092)	58,524	-
Unrealized (Gain) Loss on Derivative Instruments	(3,072,229)	14,545,477	363,414
Amortization of Deferred Rent	(19,795)	(18,573)	(18,573)
Share - Based Compensation Expense	6,164,324	3,566,133	1,213,292
Changes in Working Capital and Other Items:			
Increase in Trade Receivables	(29,385,183)	(15,008,636)	(4,996,070)
Decrease in Other Receivables	-	-	874,453
Increase in Prepaid Expenses	(140,726)	(202,089)	(72,052)
Decrease (Increase) in Other Current Assets	158,507	(274,653)	(158,334)
Increase in Accounts Payable	2,486,667	42,080,670	4,484,724
Increase (Decrease) in Accrued Expenses	128,183	(314,148)	(953,098)
Net Cash Provided by Operating Activities	85,149,526	73,307,220	9,812,910
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchases of Oil and Gas Properties and Development Capital Expenditures	(341,363,955)	(180,400,555)	(47,061,666)
Advances to Operators	(4,304,824)	(11,771,616)	(1,449,485)
Proceeds from Sale of Oil and Gas Properties	5,027,162	297,877	-
Proceeds from Sale of Available for Sale Securities	58,606,328	34,699,651	800,000
Purchase of Available for Sale Securities	(18,381,690)	(48,679,264)	(24,106,294)
Purchase of Other Equipment and Furniture	(450,822)	(2,039,543)	(31,256)
Net Cash Used for Investing Activities	(300,867,801)	(207,893,450)	(71,848,701)
CASH FLOWS FROM FINANCING ACTIVITIES			
Advances on Revolving Credit Facility	79,900,000	5,300,000	29,750,000
Repayments on Revolving Credit Facility	(10,000,000)	(5,300,000)	(29,750,000)
Payments on Line of Credit	-	(834,492)	(816,228)
(Decrease) Increase in Subordinated Notes, net	-	(500,000)	500,000
Debt Issuance Costs Paid	(449,837)	(395,355)	(1,190,061)
Repurchase of Common Stock	(1,081,132)	-	-
Proceeds from Exercise of Warrants	1,500,000	-	-
Proceeds from the Issuance of Common Stock - Net of Issuance Costs	-	282,193,406	68,994,736
Proceeds from Exercise of Stock Options	18,130	-	-

Net Cash Provided by Financing Activities	69,887,161	280,463,559	67,488,447
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(145,831,114)	145,877,329	5,452,656
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	152,110,701	6,233,372	780,716
CASH AND CASH EQUIVALENTS – END OF PERIOD	$6,279,587	$152,110,701	$6,233,372
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Period for Interest	$286,710	$169,232	$624,717
Cash Paid During the Period for Income Taxes	$2,300	$-	$-
Non-Cash Financing and Investing Activities:			
Purchase of Oil and Gas Properties through Issuance of Common Stock	$-	$12,679,422	$1,115,738
Payment of Compensation through Issuance of Common Stock	$19,278,461	$8,733,215	$1,213,292
Capitalized Asset Retirement Obligations	$401,241	$232,258	$137,222
Cashless Exercise of Stock Options	$-	$-	$518,000
Fair Value of Warrants Issued for Debt Issuance Costs	$-	$-	$221,153
Non-Cash Compensation Capitalized in Oil and Gas Properties	$13,114,137	$5,167,082	$1,226,162
Payment of Debt Issuance Costs through Issuance of Common Stock	$-	$-	$475,200

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

NORTHERN OIL AND GAS, INC.
STATEMENT OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010, AND 2009

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance – December 31, 2008	34,120,103	$34,121	$51,692,776	$ (240,774)	$ (1,957,060)	$49,529,063
Issuance of Common Stock	9,790,941	9,791	76,433,911	-	-	76,443,702
Warrants Issued Included in Debt Issuance Costs	-	-	221,153	-	-	221,153
Share Based Compensation	-	-	366,690	-	-	366,690
Net Change in Cash Flow Hedge Derivatives	-	-	-	(1,483,639)	-	(1,483,639)
Unrealized Gain on Short-Term Investments	-	-	-	(486,207)	-	(486,207)
Costs of Capital Raise	-	-	(3,785,264)	-	-	(3,785,264)
Income Tax Provision for Share Based Compensation	-	-	(45,000)	-	-	(45,000)
Net Income	-	-	-	-	2,798,952	2,798,952
Balance - December 31, 2009	43,911,044	$43,912	$124,884,266	$ (2,210,620)	$ 841,892	$123,559,450
Issuance of Common Stock	18,218,380	18,217	299,841,519	-	-	299,859,736
Share Based Compensation	-	-	4,439,101	-	-	4,439,101
Net Change in Cash Flow Hedge Derivatives	-	-	-	711,554	-	711,554
	-	-	-	553,135	-	553,135

Net Change in Unrealized Gain(Loss) on Short-term Investments						
Cost of Capital Raises	-	-	(692,794)	-	-	(692,794)
Income Tax Provision for Share Based Compensation	-	-	12,000	-	-	12,000
Net Income	-	-	-	-	6,917,300	6,917,300
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

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

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2011

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 and development of crude oil and natural gas properties. The Company’s common stock trades on the NYSE Amex Equities Market under the symbol “NOG”.

The Company acquires interests in crude oil and natural gas acreage and drilling projects, primarily in North Dakota and Montana that target the Bakken and Three Forks formations. In addition to developing its acreage the Company acquires non-operated working interests in wells within its area of operations. As of December 31, 2011, approximately 31% of our 168,843 total net mineral acres were developed. As of December 31, 2010, approximately 14% of our 153,170 total net mineral 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, 2011, 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, except for what has been disclosed in Note 5, which required recognition or disclosure in the financial statements.

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, fair value of certain investments, 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.

Short-Term Investments

All United States Treasuries that were included in short-term investments were considered available-for-sale and were carried at fair value. The short-term investments were considered current assets due their maturity term or the

Company's ability and intent to use them to fund current operations. The unrealized gains and losses related to these securities were included in accumulated other comprehensive income. The realized gains and losses related to these securities are included in other income (expense) in the statement of income.

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 fifteen 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. Northern has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was $298,137, $176,595, and $91,794 for the years ended December 31, 2011, 2010, and 2009.

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, 2011, 2010, and 2009:

	Year Ended December 31,		
	2011	2010	2009
Capitalized Certain Payroll and Other Internal Costs	$16,952,995	$6,559,741	$2,616,262
Capitalized Interest Costs	405,984	59,711	624,717
Total	$17,358,979	$6,619,452	$3,240,979

As of December 31, 2011, the Company held leasehold interests in the Williston Basin on acreage located in North Dakota and Montana targeting the Bakken and Three Forks formations. Additionally, Northern held leasehold acreage in Yates County, New York that targets Trenton/Black River, Marcellus and Queenstown-Medina 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, 2011 and 2010, the Company sold acreage and production for $5.0 million and $298,000, respectively. The proceeds for these sales were applied to reduce the capitalized costs of crude oil and natural gas properties. There were no property sales for the year ended December 31, 2009.

Capitalized costs associated with impaired properties and capitalized cost 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, 2011 and 2010, the Company included $9.0 million and $1.6 million of costs related to expired leases.

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. As of December 31, 2011, 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 form 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 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

The Company has incurred direct costs related to the revolving credit facility (see Note 5) of $2.7 million. The debt issuance costs are being amortized over the term of the credit facility.

The amortization of debt issuance costs for the years ended December 31, 2011, 2010 and 2009 was $430,760, $455,302 and $459,343, 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. Northern uses 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 any imbalance situation. As of December 31, 2011, 2010 and 2009, 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.

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, 2011 and 2010.

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 warants 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, 2011, 2010 and 2009 are as follows:

	Year Ended December 31,		
	2011	2010	2009
Weighted average common shares outstanding – basic	61,789,289	50,387,203	36,705,267
Plus: Potentially dilutive common shares			
Stock options, warrants, and restricted stock	406,051	391,042	171,803
Weighted average common shares outstanding – diluted	62,195,340	50,778,245	36,877,070
Restricted stock excluded from EPS due to the anti-dilutive effect	29,876	-	37,065

As of December 31, 2011, 2010 and 2009, potentially dilutive shares from stock options were 262,463, 265,293 and 300,000, respectively. These options are all exercisable at December 31, 2011, 2010 and 2009, at an exercise price of $5.18.

The Company also has potentially dilutive restricted stock grants outstanding of 1,216,992, 1,135,622 and 325,330 at December 31, 2011, 2010, and 2009.

In addition, as of December 31, 2010 and 2009, there were 300,000 warrants that were issued in conjunction with the February 2009 revolving credit facility with CIT that remained outstanding and exercisable. The warrants were exercised at a price of $5.00 per share in January 2011.

Derivative Instruments and Price Risk Management

We use derivative instruments from time to time to manage market risks resulting from fluctuations in the prices of crude oil. 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 crude oil 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 crude oil at a future date.

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 in addition, 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 loss on settled derivatives and unrealized gains or losses are recorded to gain (loss) on mark-to-market of derivative instruments on the statement of income rather than as a component of accumulated other comprehensive income (loss) or other income (expense). See Note 15 for a description of the derivative contracts which the Company executed during 2011 and 2010.

Prior to November 1, 2009, at the inception of a derivative contract, we designated the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, we 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. We historically measured hedge effectiveness on a quarterly basis and hedge accounting would be discontinued prospectively if it determined that the derivative is 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 is delivered. If we determine that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative are 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. Our derivatives historically consisted primarily of cash flow hedge transactions in which we were 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.

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 identified at December 31, 2011, 2010, and 2009.

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.

Presentation of Comprehensive Income

In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05). The guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The standard will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB issued Comprehensive Income (Topic 220) — Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU No. 2011-12). The FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The standard, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this standard on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs

In May 2011, the FASB issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU No. 2011-04). The standard generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the standard includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This standard is effective for the Company on January 1, 2012. The standard will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Balance Sheet Offsetting

In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which updates the Codification to require 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 updates to the disclosure requirements of the Codification do not affect the presentation of amounts in the balance sheet, and are effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those periods. The Company does not expect the implementation of this disclosure guidance to have a material impact on its financial statements.

NOTE 3 SHORT-TERM INVESTMENTS

All United States Treasuries that are included in short-term investments are considered available-for-sale and are carried at fair value. The short-term investments were considered current assets due to their maturity term or the company's ability and intent to use them to fund current operations. The unrealized gains and losses related to these securities were included in accumulated other comprehensive income (loss). The realized gains and losses related to these securities are included in other income in the statement of income.

At December 31, 2011, the Company held no short-term investments. The following is a summary of the Company's short-term investments as of December 31, 2010:

	Cost at December 31, 2010	Unrealized (Loss)	Fair Market Value at December 31, 2010
United States Treasuries	$40,009,546	$(282,846)	$39,726,700

For the year ended December 31, 2011, the Company realized gains of $215,092 on the sale of short-term investments. For the year ended December 31, 2010, the Company realized losses of $58,524 on the sale of short-term investments. There were no realized gains and losses on the sale of short-term investments for the year ended December 31, 2009.

The Company reviews these investments on a quarterly basis to determine if it is probable that the Company will realize some portion of the unrealized loss. In determining if the difference between cost and estimated fair value of the short-term investments was deemed either temporary or other-than-temporary impairment, the Company evaluated each type of short-term investment using a set of criteria including decline in value, duration of the decline, period until anticipated recovery, nature of investment, probability of recovery, financial condition and near-term prospects of the issuer, the Company's intent and ability to retain the investment, attributes of the decline in value, status with rating agencies, status of principal and interest payments and any other issues related to the underlying securities. The Company determined the decline in the fair values in all of the short-term investments were temporary as of December 31, 2010.

NOTE 4 CRUDE OIL AND NATURAL GAS PROPERTIES

The value to 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 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. Certain acquisitions in 2010 and 2009 were purchased using the services of, or purchased from, parties considered to be related to the Company or the Company's Chief Executive Officer, Michael L. Reger. No such transactions occurred during 2011. See Note 7. All transactions involving related parties were approved by the Company's board of directors or audit committee.

2011 Acquisitions

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

2010 Acquisitions

During 2010, the Company acquired approximately 56,858 net mineral acres, for an average cost of $1,043 per net acre, in all of its key prospect areas in the form of both effective leases and top-leases.

During 2010, the Company acquired acreage using common stock for a portion of the acquisition cost. A summary of the significant transactions is as follows:

Date	Net Acres Acquired	Common Stock Issued	Fair Value of Common Stock Issued	Cash Consideration	Total Consideration
June 2010	3,498	382,645	$5,360,856	$ 741,464	$ 6,102,320
July 2010	3,352	444,186	$6,529,534	-	$ 6,529,534

In December of 2010, the Company acquired a 50% working interest from Slawson Exploration Company, Inc. ("Slawson") in approximately 14,538 net acres in Richland County, Montana for approximately $1.7 million in cash. That acquisition accounted for approximately 12.8% of the total number of net acres the Company acquired during 2010. No other acquisition involved more than 10% of the total acreage the Company acquired during the year.

Divestitures

In November 2009, the Company agreed to participate in the exploration and development of Slawson's Anvil project in Roosevelt and Sheridan Counties, Montana and Williams County, North Dakota. 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, 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.

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 117,000 net acres and 132,000 net acres of undeveloped leasehold interests at December 31, 2011 and 2010, 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, 2011 by year incurred.

	Year Ended December 31,			
	2011	2010	2009	Prior Years
Property Acquisition	$46,814,712	$50,613,193	$14,773,003	$25,565,530
Development	18,465	-	-	-
Total	$46,833,177	$50,613,193	$14,773,003	$25,565,530

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 by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling, with the exception of the defined drilling projects with Slawson described below.

As of December 31, 2011, the Company was participating in three defined drilling projects with Slawson covering an aggregate of approximately 17,400 net acres of leasehold interests held by the Company. The Windsor project area includes approximately 2,700 net acres held by the Company, primarily located in Mountrail and surrounding counties of North Dakota. The South West Big Sky project includes approximately 3,900 total net acres held by the Company in Richland County, Montana. The Lambert project includes approximately 10,800 net acres held by the Company in Richland County, Montana. Purchases of properties and development capital expenditures that were in accounts payable and not yet paid in cash at December 31, 2011 were approximately $106 million.

NOTE 5 REVOLVING CREDIT FACILITY

Credit Facility

In February 2009, the Company completed the closing of a revolving credit facility with CIT that provided up to a maximum principal amount of $25 million of working capital for exploration and production operations.

In May 2010, the Company completed the assignment of its revolving credit facility to Macquarie Bank Limited ("Macquarie") from CIT. In connection with the assignment the Company and Macquarie entered into an Amended and Restated Credit Agreement governing the facility.

In August 2011, the Company and Macquarie entered into a Second Amended and Restated Credit Agreement (the "Restated Credit Agreement") governing the Company's credit facility (the "Credit Facility"). The Credit Facility provides that the aggregate maximum credit may be increased in the future to up to $500 million and is secured by substantially all of the Company's assets. The Company had $69.9 million of borrowings under Credit Facility at December 31, 2011 and no borrowings at December 31, 2010. At December 31, 2011, the Company had a borrowing base of $150 million, subject to a $120 million aggregate maximum credit amount then in effect. As of December 31, 2011, there was $50.1 million of available borrowing capacity under this facility, which is net of the $69.9 million in borrowings. The borrowing base of funds available under the Credit Facility will be re-determined semi-annually. The Credit Facility terminates on May 26, 2014. As of December 31, 2011 the Company's borrowings were at an average rate of 2.78%.

The Company has the option to designate the reference rate of interest for each specific borrowing under the Credit Facility as amounts are advanced. Borrowings based upon the London Interbank Offered Rate ("LIBOR") will bear interest at a rate equal LIBOR plus a spread ranging from 2.5% to 3.25% depending on the percentage of borrowings 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 2% to 2.5%, depending on the percentage of borrowing base that is currently advanced. The Company has the option to designate either pricing mechanism. Interest payments are due under the 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 Credit Facility.

The 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 ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 3.5 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. The Company was in compliance with its covenants under the bank credit facility at December 31, 2011.

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

Subsequent Event

On February 28, 2012, the Company entered into an amended and restated revolving bank facility, which replaced its previous bank credit facility. The new facility, secured by substantially all of the Company's assets, provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. At February 28, 2012, the facility amount was $750 million, the borrowing base was $250 million and there was an outstanding balance of $147.5 million leaving $102.5 million of borrowing capacity available under the facility. The new bank credit facility provides for a borrowing base subject to redetermination semi-annually each April and October and for event-driven unscheduled redeterminations. The new bank group is comprised of a group of commercial banks, with no one bank holding more than 25% of the total facility. The loan matures on January 1, 2017. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.75% to 1.75% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.75% to 2.75%. The applicable spread is dependent upon borrowings relative to the borrowing base. 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 0.375% to 0.50%. At closing, the commitment fee was 0.50% and the interest rate margin was 2.25% on its LIBOR loans and 1.25% on its base rate loans.

NOTE 6 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 common stock since the beginning of 2009:

	Year Ended December 31,		
	2011	2010	2009
Beginning balance	62,129,424	43,911,044	34,120,103
Public offerings	-	16,042,500	8,750,000
Stock based compensation	161,628	213,075	283,670
Stock options exercised	3,500	22,314	100,000
Restricted stock grants (Note 8)	786,263	1,058,000	361,330
	-	-	180,000

Stock issued in exchange for debt issuance costs			
Warrants exercised	300,000	-	-
Issued for acreage purchases/acquisitions	-	882,491	128,097
Share Adjustment related to Kentex Transaction	-	-	41,989
Other Surrenders	(50,394)	-	(54,145)
Ending balance	63,330,421	62,129,424	43,911,044

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 executives 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.

2010 Activity

In 2010, the Company issued 213,075 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 $4.3 million. The value of the stock was between $12.32 and $22.85 per share, the market value of the shares of common stock on the date the stock was issued. The Company expensed approximately $1.7 million in share-based compensation related to these fully vested shares in the year ended December 31, 2010. The remainder of fair value was capitalized into the full cost pool.

In April 2010, the Company entered into an underwriting agreement to sell 5,750,000 shares of common stock at a price of $15.00 less an underwriting discount of $0.60 per share for total net proceeds of approximately $82.8 million, after deducting underwriters' discounts. The Company incurred costs of $300,000 related to this offering. These costs were netted against the proceeds of the offering through additional paid-in capital.

In November 2010, the Company entered into an underwriting agreement to sell 10,292,500 shares of common stock at a price of $20.25 less an underwriting discount of $0.81 per share for total net proceeds of approximately $200.1 million, after deducting underwriters' discounts. The Company incurred costs of $392,795 related to this offering. These costs were netted against the proceeds of the offering through additional paid-in capital.

During 2010, the Company acquired leasehold interest using common stock for a portion of the acquisition cost. A summary of these transactions is as follows:

Date	Common Stock Issued	Fair Value of Common Stock Issued
March 2010	10,287	$99,475
June 2010	382,645	5,360,856
June 2010	14,167	238,006
July 2010	444,186	6,529,534

July 2010	31,206	451,551

2009 Activity

In 2009, the Company issued 283,670 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 $2.1 million. The value of the stock was between $2.84 and $9.70 per share, the market value of the shares of common stock on the date the stock was issued. The Company expensed approximately $1.0 million in share-based compensation related to these fully vested shares in the year ended December 31, 2009. The remainder of fair value was capitalized into the full cost pool.

On February 27, 2009, the Company closed on a revolving credit facility with CIT Capital USA, Inc. ("CIT"). As part of obtaining this credit facility agreement the Company entered into an engagement with Cynergy Advisors, LLC (Cynergy). As part of the compensation for the work performed on obtaining the financing, Cynergy received 180,000 shares of restricted common stock of the Company. The fair value of the restricted stock was $475,200 or $2.64 per share, the market value of a share of common stock on the date the financing closed. The fair value of this stock was capitalized as debt issuance costs and is being amortized over the amended term of the financing.

In June 2009, the Company completed a registered direct offering of 2,250,000 shares of common stock at a price of $6.00 per share for total gross proceeds of $13,500,000. The Company incurred costs of $813,237 related to this offering. These costs were netted against the proceeds of the offering through additional paid-in capital.

On October 26, 2009, the Company deposited 41,989 shares of common stock in a specially-designated shareholder account that had been previously-created to hold shares of its common stock represented by certificates that appear in our stock transfer records but were known to have been cancelled and their underlying shares transferred between July of 1987 and August of 1999. An aggregate of 58,268 shares of the Company's common stock is held in the specially-designated shareholder account, which, following a substantial review of all available historical stock transfer records, the Company concluded represents the maximum number of shares of the Company's common stock that could potentially be released to shareholders who may be able to establish a valid claim to such shares due to previously unrecognized issues with the Company's stock transfer records. These shares are considered issued and outstanding and are included in the total number of shares outstanding disclosed on the cover page of this report.

On November 4, 2009, the Company completed a registered direct offering of 6,500,000 shares of common stock at a price of $9.12 per share for total gross proceeds of $59,280,000. The Company incurred costs of $2,972,027 related to the offering. These costs were netted against the proceeds of the offering through additional paid-in capital.

In December 2009, a director of the Company exercised 100,000 stock options granted to him in 2007. The exercise of these options was completed through a cashless exercise whereas the company repurchased 52,061 of common shares to issue the common shares related to this option exercise.

During 2009, the Company acquired leasehold interest using common stock for a portion of the acquisition cost. A summary of these transactions is as follows:

Date	Common Stock Issued	Fair Value of Common Stock Issued
April 2009	49,092	$224,879
December 2009	79,005	890,859

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 will allow the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions. The Company has not made any repurchases under this program to date.

Shelf Registration

In May 2010, the Company filed a shelf registration with the Securities and Exchange Commission to potentially offer securities which include debt securities or common stock. The securities will be offered at prices and on terms to be determined at the time of sale.

NOTE 7 RELATED PARTY TRANSACTIONS

The Company has purchased leasehold interests from South Fork Exploration, LLC ("SFE") pursuant to a continuous lease program that coved specific agreed upon sections of townships and ranges in Burke, Divide, and Mountrail Counties of North Dakota where SFE previously acquired leasehold interests on the Company's behalf. The Company terminated this agreement with SFE. This program differed from other arrangements where the Company may purchase specific leases in one-time, single closing transactions. In 2009, the Company paid a total of $501,603 related to previously acquired leasehold interests. In 2010, the Company paid a total of $5,000 related to previously acquired leasehold interests. The Company made no payments to SFE in 2011. Because each lessor separately negotiated its own desired royalty, SFE's over-riding royalty interest varied from lease to lease. The Company received a net revenue interest ranging from 80.25% to 82.5% net revenue interest in the acquired leases, which is net of royalties and overriding royalties. SFE's president is J.R. Reger, the brother of the Company's Chief Executive Officer, Michael Reger. J.R. Reger is also a shareholder in the Company.

The Company has also purchased leasehold interests from Montana Oil Properties ("MOP"). In 2009, the Company paid MOP a total of $63,234 related to previously acquired leasehold interests. In July 2010, the Company paid MOP a total of $269,821 for leases and reimbursement costs pertaining to two separate wells in Mountrail County, North Dakota. The Company made no payments to MOP in 2011. MOP is controlled by Mr. Tom Ryan and Mr. Steven Reger, both are relatives of the Company's Chief Executive Officer, Michael Reger.

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 2009, the Company paid Gallatin a total of $22,223 related to previously acquired leasehold interests. In 2010, the Company paid Gallatin a total of $15,822 related to previously acquired leasehold interests. In 2011, the Company paid Gallatin a total of approximately $6,500 related to previously acquired leasehold interests.

The Company had a securities account with Morgan Stanley Smith Barney that was managed by Kathleen Gilbertson, a financial advisor with that firm who is the sister of the Company's president and former director, Ryan Gilbertson. The Company closed this account in August 2011.

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

NOTE 8 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

On April 26, 2011, the board of directors approved an amendment and restatement of the Northern Oil and Gas, Inc. 2009 Equity Incentive Plan (the "Plan"), which was approved at the annual meeting of shareholders. An additional 1,000,000 shares were authorized for grant under the Plan, resulting in an aggregate of 4,000,000 shares authorized for past and future grants under the Plan. The Plan is intended to provide a means whereby the Company may be able, by granting stock options and shares of restricted stock, 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, 2011, 2010 and 2009, the Company issued 786,263, 1,058,000 and 361,330, respectively, restricted shares of common stock as compensation to officers, employees, and directors of the Company. The restricted shares vest over various terms with all restricted shares vesting no later than October 15, 2015. As of December 31, 2011, there was approximately $17.0 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.

The following table reflects the outstanding restricted stock awards and activity related thereto for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31, 2011		Year Ended December 31, 2010		Year Ended December 31, 2009	
	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	1,135,622	$13.28	325,330	$9.01	20,000	$7.03
Shares Granted	786,263	$27.11	1,058,000	$14.08	361,330	$8.49
Lapse of Restrictions	(704,893)	$17.32	(247,708)	$11.11	(56,000)	$4.91
Restricted Shares Outstanding at the End of the Year	1,216,992	$19.87	1,135,622	$13.28	325,330	$9.01

Stock Option Awards

The Company's board of directors approved a stock option plan in October 2006 ("2006 Incentive Stock Option Plan") to provide incentives to employees, directors, officers, and consultants and under which 2,000,000 shares of common stock have been reserved for issuance. The options can be either incentive stock options or non-statutory stock options and are valued at the fair market value of the stock on the date of grant. The exercise price of incentive stock options may not be less than 100% of the fair market value of the stock subject to the option on the date of the grant and, in some cases, may not be less than 110% of such fair market value. The exercise price of non-statutory options may not be less than 100% of the fair market value of the stock on the date of grant.

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, 2011, options to purchase a total of 262,463 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 2009 Equity Incentive Plan.

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. 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 have been no stock options granted in 2011, 2010, and 2009 under the 2006 Incentive Stock Option Plan or the 2009 Equity Incentive Plan. All exercises of options during 2011, 2010, and 2009 related to 2007 grants.

Changes in stock options for the years ended December 31, 2011, 2010, and 2009 were as follows:

	Number of Shares	Weighted Average Exercise Price	Remaining Contractual Term (in Years)	Intrinsic Value
2009:				
Beginning Balance	400,000	$-	-	-
Granted	-	-	-	-
Exercised	100,000	5.18	-	-
Outstanding at December 31	300,000	5.18	7.8	1,998,000
Exercisable	300,000	5.18	7.8	1,998,000
Ending Vested	300,000	5.18	7.8	1,998,000
Weighted Average Fair Value of Options Granted During Year		$-		
2010:				
Beginning Balance	300,000	$-	-	-
Granted	-	-	-	-
Exercised	22,314	5.18	-	-
Forfeited	11,723	5.18	-	-
Outstanding at December 31	265,963	5.18	6.8	5,859,000
Exercisable	265,963	5.18	6.8	5,859,000
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		$-		

Currently Outstanding Options

No Options expired during the years ended December 31, 2011, 2010, and 2009.

The Company recorded no compensation expense related to these options for the years ended December 31, 2011, 2010, and 2009. 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 years, relating to all options that have been granted as of December 31, 2011, because the Company recognized the entire fair value of such compensation upon vesting of the options.

There were no unvested options at December 31, 2011, 2010, and 2009.

Warrants Granted February 2009

On February 27, 2009, in conjunction with the closing of a prior revolving credit facility, the Company issued CIT 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. CIT exercised the warrants in January 2011.

The following assumptions were used for the Black-Scholes model:

	February 27, 2009
Risk free rates	1 %
Dividend yield	0 %
Expected volatility	96.43 %
Weighted average expected warrant life	1.5 Years

The "fair market value" at the date of issuance for the warrants issued using the formula relied upon for calculating the fair value of warrants is as follows:

Weighted average fair value per share	$0.74
Total warrants granted	300,000
Total weighted average fair value of warrants granted	$221,153

NOTE 9 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.

NOTE 10 ASSET RETIREMENT OBLIGATION

The Company has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Initially, the fair value of a liability for an asset retirement obligation 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.

The following table summarizes the company's asset retirement obligation transactions recorded during the year ended December 31, 2011 and 2010.

	Year Ended December 31	
	2011	2010
Beginning Asset Retirement Obligation	$459,326	$206,741
Liabilities Incurred for New Wells Placed in Production	401,241	232,258
Liabilities Settled	-	(1,428)
Accretion of Discount on Asset Retirement Obligations	56,055	21,755
Ending Asset Retirement Obligation	$916,622	$459,326

NOTE 11 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.

The income tax provision for the year ended December 31, 2011, 2010, and 2009 consists of the following:

	2011	2010	2009
Current Income Taxes	$2,300	$-	$-
Deferred Income Taxes			
Federal	22,982,000	3,625,000	1,215,000
State	3,851,000	794,000	251,000
Total Expense	$26,835,300	$4,419,000	$1,466,000

The following is a reconciliation of the reported amount of income tax expense for the years ended December 31, 2011, 2010, and 2009 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:

	2011	2010	2009
Income Before Taxes and NOL	$67,446,792	$11,336,300	$4,264,952
Federal Statutory Rate	X 35 %	X 34 %	X 34 %
Taxes Computed at Federal Statutory Rates	23,606,000	3,854,000	1,450,000
State Taxes, Net of Federal Taxes	2,408,300	524,000	295,000
Executive Compensation Deductibility Limits	617,000	-	-
Other	204,000	41,000	(279,000)
Reported Provision	$26,835,300	$4,419,000	$1,466,000

At December 31, 2011, 2010 and 2009, the Company has a net operating loss carryforward for Federal income tax purposes of $220.2 million, $62.1 million and $18.5 million, respectively. If unutilized, the federal net operating losses will expire in 2027-2031.

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

	Year Ended December 31 2011	2010
Deferred Tax Assets		
Current:		
Share Based Compensation	$866,000	$727,000
Derivative Liability	3,629,000	4,414,000
Other	34,000	-
Total Current	4,529,000	5,141,000
Non-Current:		
Net Operating Loss Carryforwards (NOLs)	84,714,000	23,987,000
Derivative Liability	998,000	1,939,000
Other	58,000	29,000
Total Non-Current	85,770,000	25,955,000
Total Deferred Tax Asset	$90,299,000	$31,096,000
Deferred Tax Liabilities		
Current:		
Other	$(57,000)	$(41,000)
Total Current	(57,000)	(41,000)
Non-Current:		
Crude Oil and Natural Gas Properties and Other Property	(121,699,000)	(35,122,000)
Total Non-Current	(121,699,000)	(35,122,000)
Total Deferred Tax Liability	(121,756,000)	(35,163,000)
	-	-
Total Net Deferred Tax Liability	$(31,457,000)	$(4,067,000)

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, 2011, 2010 and 2009, the Company did not recognize any interest or penalties in its statement of income, nor did it have any interest or penalties accrued in its balance sheet at December 31, 2011 and 2010 relating to unrecognized benefits.

The tax years 2011, 2010, 2009, and 2008 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject.

NOTE 12 OPERATING LEASES

Vehicles

The Company leases vehicles under noncancelable operating leases. Total lease expense under the agreements was approximately $63,000, $58,000 and $52,000 for the years ended December 31, 2011, 2010, and 2009, respectively.

Minimum future lease payments under these vehicle leases are as follows:

Year Ended December 31,	Amount
2012	$63,000
2013	39,000
2014	9,000
Total	$111,000

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. Total rent expense under the agreements was approximately $150,000, $148,000 and $142,000 for the years ended December 31, 2011, 2010, and 2009, respectively.

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

Year Ended December 31,	Amount
2012	$230,000
2013	233,000
2014	242,000
2015	177,000
Total	$882,000

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 13 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 of 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, 2011 and 2010.

	Fair Value Measurements at December 31, 2011 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 Liability (crude oil swaps and collars)	$-	$(9,363,068)	$ -
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(2,574,903)	-
Credit Facility – Long Term Liability	-	(69,900,000)	
Total	$-	$(81,837,971)	$ -

	Fair Value Measurements at December 31, 2010 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 Liability (crude oil swaps and collars)	$-	$(11,145,319)	$ -
Commodity Derivatives – Non-Current Liability (crude oil swaps and collars)	-	(5,022,657)	-
Short-Term Investments (See Note 3)	39,726,700	-	-
Total	$39,726,700	$(16,167,976)	$ -

There were no transfers of financial assets or liabilities between Level 1 and Level 2 inputs for the year ended December 31, 2011.

Level 1 assets consist of US Treasury Notes, the fair value of these treasuries is based on quoted market prices.

Level 2 liabilities consist of derivative liabilities (see Note 15) and our Credit Facility (see Note 5). The fair value of the Company's derivative financial instruments is determined based on spot prices and the notional quantities. The fair value of all derivative contracts is reflected on the balance sheet. The current derivative liability amounts represent the fair values expected to be settled in the subsequent year. The book value of our Credit Facility approximates fair value because of its floating rate structure.

NOTE 14 FINANCIAL INSTRUMENTS

The Company's non-derivative financial instruments include cash and cash equivalents, accounts receivable, short-term investments, accounts payable and line of credit. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable, and the book value of our credit facility approximates fair value becuase of its floating rate structure.

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, 2011 and 2010 do not represent significant credit risks as they are dispersed across many counterparties. The Company has determined that no allowance for doubtful accounts is necessary at December 31, 2011 and 2010. As of December 31, 2011, outstanding derivative contracts with Macquarie Bank Limited represent all of the Company's crude oil volumes hedged. Macquarie Bank Limited has investment-grade ratings from Moody's and Standard & Poor and is the lender under the Company's credit facility and management believes this does not represent a significant credit risk.

NOTE 15 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 are recorded to loss on settled derivatives and unrealized gains or losses are recorded to gain (loss) on mark-to-market of derivative instruments on the statement of income rather than as a component of other comprehensive income (loss) or other income (expense).

The Company has a master netting agreement on each of the individual crude oil contracts 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.

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 statement of 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 totals approximately $101,000 and $1.3 million as of December 31, 2011 and 2010, respectively. The Company has recorded that amount as accumulated other comprehensive income in stockholders' equity and the entire amount will be amortized into revenues as the original forecasted hedged crude oil production occurs in the first quarter of 2012.

Crude Oil Derivative Contracts Cash-flow Not Designated as Hedges

The Company realized a loss on settled derivatives of $13,407,878, $469,607 and $624,541 and a mark-to-market of derivatives gain of $3,072,229 and a mark-to-market of derivative loss of $14,545,477 and $363,414 on derivative instruments for the years ended December 31, 2011, 2010 and 2009, respectively.

The following table reflects open commodity swap contracts as of December 31, 2011, the associated volumes and the corresponding weighted average NYMEX reference price.

Settlement Period	Oil (Barrels)	Fixed Price	Weighted Avg NYMEX Reference Price
Oil Swaps			
01/01/12 – 02/29/12	3,000	51.25	98.90
01/01/12 – 6/30/12	138,000	80.00	99.19
01/01/12 – 6/30/12	198,000	81.50	99.19
01/01/12 – 6/30/12	60,000	85.50	99.20
01/01/12 – 12/31/12	376,000	95.15	98.52
01/01/12 – 12/31/12	240,000	100.00	98.81

As of December 31, 2011, the Company had a total volume on open commodity swaps of 1,015,000 barrels at a weighted average price of approximately $90.87. All open commodity swap contracts as of December 31, 2011 settle during the year ended December 31, 2012.

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 and natural gas 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, 2011.

Term	Oil (Barrels)		Price	Basis
Costless Collars				
01/01/12 – 12/31/12	141,877	$	85.00/$95.25	NYMEX
01/01/13 – 12/31/13	760,794	$	85.00/$98.00	NYMEX
01/01/12 – 12/31/13	420,730	$	90.00/$103.50	NYMEX

At December 31, 2011 and 2010, the Company had derivative financial instruments recorded on the balance sheet as set forth below:

		December 31, Estimated Fair Value	
Type of Contract	Balance Sheet Location	2011	2010
Derivative Assets:			
Swap Contracts	Current liabilities	$285,126	$-
Costless Collars	Current liabilities	1,932,884	-
Costless Collars	Non-current liabilities	8,766,484	-
Total Derivative Assets		$10,984,494	$-
Derivative Liabilities:			
Swap Contracts	Current liabilities	$(8,383,588)	$(11,145,319)
Costless Collars	Current liabilities	(3,197,490)	-
Costless Collars	Non-current liabilities	(11,341,387)	(5,022,657)
Total Derivative Liabilities		$(22,922,465)	$(16,167,976)

The following disclosures are applicable to the Company's financial statements, as of December 31, 2011, 2010 and 2009:

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		
		2011	2010	2009
Commodity – Cash Flow	Loss on Settled Derivatives	$1,157,775	$1,157,554	$363,414

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company has netting arrangements with Macquarie Bank Limited that provide for offsetting payables against receivables from separate derivative instruments.

NOTE 16 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, 2011, 2010, and 2009:

	2011			2010			2009		
	Net Income	Shares	Per Share	Net Income	Shares	Per Share	Net Income	Shares	Per Share
Basic EPS	$40,611,492	61,789,289	$0.66	$6,917,300	50,387,203	$0.14	$2,798,952	36,705,267	$0.08
Dilutive Effect of Options	-	406,051	(0.01)	-	391,042		-	171,803	
Diluted EPS	$40,611,492	62,195,340	$0.65	$6,917,300	50,778,245	$0.14	$2,798,952	36,877,070	$0.08

For the year ended December 31, 2011 restricted stock of 29,876 shares of common stock were excluded from EPS due to the anti-dilutive effect.

For the year ended December 31, 2009 options and warrants to purchase 21,678 and 7,476 shares of common stock were not considered in calculating diluted earnings per share because the exercise prices were greater than the average market price of common shares during the year and, therefore, the effect would be anti-dilutive.

NOTE 17 COMPREHENSIVE INCOME

In addition to net income, comprehensive income includes all changes in equity during a period, except those resulting from investments and distributions to shareholders of the Company.

For the periods indicated, comprehensive income consisted of the following:

	Year ended December 31,		
	2011	2010	2009
Net Income	$40,611,492	$6,917,300	$2,798,952
Unrealized gains (losses) on Marketable Securities (net of tax of $109,000, $349,000 and $290,000 at December 31, 2011, 2010 and 2009)	173,846	553,135	(486,207)
Reclassification of derivative instruments included in income (Net of tax of $448,000, $446,000 and $933,000 at December 31, 2011, 2010 and 2009)	709,776	711,554	(1,483,639)
Comprehensive Income	$41,495,114	$8,181,989	$829,106

As of December 31, 2011, accumulated other comprehensive loss consisted solely of loss on cash flow hedge derivatives.

NOTE 18 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, at the Company's discretion. During 2011, 2010 and 2009, the Company provided a match contribution equal to 100% of an eligible employee's deferral contribution, up to 6% of the employee's earnings up to $16,500. The Company contributed approximately $103,000, $80,000 and $66,400 to the 401(k) plan for the years ended December 31, 2011, 2010 and 2009, respectively.

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,		
	2011	2010	2009
Costs Incurred for the Year:			
Proved Property Acquisition	$ 53,497,199	$ 2,236,167	$ 30,800,883
Unproved Property Acquisition	57,867,660	72,308,719	-
Development	302,594,511	123,933,003	18,739,905
Total	$ 413,959,370	$ 198,477,889	$ 49,540,788

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, 2011 by year incurred.

	Year Ended December 31,			
	2011	2010	2009	Prior Years
Property Acquisition	$46,814,712	$50,613,193	$14,773,003	$25,565,530
Development	18,465	-	-	-
Total	$46,833,177	$50,613,193	$14,773,003	$25,565,530

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, 2008	216,451	727,665
Revisions of Previous Estimates	(27,820)	(93,819)
Extensions, Discoveries and Other Additions	1,619,597	5,456,261
Production	(47,305)	(274,528)
Proved Developed and Undeveloped Reserves at December 31, 2009	1,760,923	5,815,579
Revisions of Previous Estimates	625,103	514,899
Extensions, Discoveries and Other Additions	8,298,347	8,513,064
Production	(234,411)	(849,845)
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
Proved Developed Reserves:		
December 31, 2008	216,451	727,665
December 31, 2009	727,237	2,247,718
December 31, 2010	3,513,427	5,840,745
December 31, 2011	8,452,653	14,338,576
Proved Undeveloped Reserves		
December 31, 2008	-	-
December 31, 2009	1,033,686	3,567,861
December 31, 2010	6,936,535	8,152,952
December 31, 2011	21,216,511	27,538,402

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 (formerly SFAS 69). 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 carryforwards 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,		
	2011	2010	2009
Future Cash Inflows	$3,959,403,500	$1,038,703,438	$315,142,688
Future Production Costs	(925,165,656)	(271,843,571)	(105,982,773)
Future Development Costs	(624,607,500)	(161,853,922)	(54,011,133)
Future Income Tax Expense	(740,132,743)	(199,197,425)	(43,761,765)
Future Net Cash Inflows	1,669,497,601	405,808,520	111,387,017
10% Annual Discount for Estimated Timing of Cash Flows	(830,800,217)	(195,195,729)	(43,580,456)
Standardized Measure of Discounted Future Net Cash Flows	$838,697,384	$210,612,791	$67,806,561

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, 2011	$6.18	$90.17
December 31, 2010	$5.04	$70.46
December 31, 2009	$3.93	$53.00

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

	Year Ended December 31,		
	2011	2010	2009
Beginning of Period	$210,612,791	$67,806,561	$11,786,054
Sales of Oil and Natural Gas Produced, Net of Production Costs	(132,095,155)	(50,721,827)	(13,116,475)
Extensions and Discoveries	756,304,288	185,403,280	74,946,755
Previously Estimated Development Cost Incurred During the Period	23,941,194	3,350,016	1,321,948
Net Change of Prices and Production Costs	140,217,589	88,564,348	4,352,381
Change in Future Development Costs	(11,285,152)	(3,003,304)	-
Revisions of Quantity and Timing Estimates	13,491,953	(3,237,346)	(1,650,626)
Accretion of Discount	29,551,146	8,781,249	1,178,605
Change in Income Taxes	(177,737,162)	(84,898,666)	(20,005,322)
Purchase of Reserves in Place	-	-	9,579,951
Other	(14,304,107)	(1,431,520)	(586,710)
End of Period	$838,697,384	$210,612,791	$67,806,561

QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Quarterly data for the years end December 31, 2011, 2010, and 2009 is as follows:

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2011				
Revenue	$2,526,749	$50,826,098	$69,050,038	$26,986,208
Expenses	14,859,331	17,103,690	23,079,016	27,096,826
Income (Loss) from Operations	(12,332,582)	33,722,408	45,971,022	(110,618)
Other Income (Expense)	767,040	(229,508)	(180,800)	(160,170)
Income Tax Provision (Benefit)	(4,507,700)	13,060,000	17,173,000	1,110,000
Net Income (Loss)	(7,057,842)	20,432,900	28,617,222	(1,380,788)
Net Income (Loss) Per Common Share – Basic	(0.11)	0.33	0.46	(0.02)
Net Income (Loss) Per Common Share – Diluted	(0.11)	0.33	0.46	(0.02)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2010				
Revenue	$7,221,514	$16,231,773	$9,883,821	$11,221,992
Expenses	4,596,936	6,133,565	8,159,485	14,163,826
Income (Loss) from Operations	2,624,578	10,098,208	1,724,336	(2,941,834)
Other Income (Expense)	(87,948)	(144,342)	(117,110)	180,412
Income Tax Provision (Benefit)	977,000	3,833,000	620,000	(1,011,000)
Net Income (Loss)	1,559,630	6,120,866	987,226	(1,750,422)
Net Income (Loss) Per Common Share – Basic	0.04	0.12	0.02	(0.03)
Net Income (Loss) Per Common Share – Diluted	0.04	0.12	0.02	(0.03)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2009				
Revenue	$658,268	$2,275,084	$4,855,972	$6,432,175
Expenses	1,047,614	1,437,445	2,530,315	5,077,164
Income (Loss) from Operations	(389,346)	837,639	2,325,657	1,355,011
Other Income (Expense)	(43,527)	(139,243)	321,589	(2,828)
Income Tax Provision (Benefit)	(174,000)	280,000	1,059,000	301,000
Net Income (Loss)	(258,873)	418,396	1,588,246	1,051,183
Net Income (Loss) Per Common Share – Basic	(0.01)	0.01	0.04	0.03
Net Income (Loss) Per Common Share – Diluted	(0.01)	0.01	0.04	0.03