NORTHERN OIL & GAS, INC.
Form 10-K/A
November 05, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K/A
(AMENDMENT NO. 2)

(Mark One)

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

For the fiscal year ended December 31, 2009

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)

Nevada	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
(Title of Class)

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

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 T

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 T No £

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

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

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

Large Accelerated Filer	£	Accelerated Filer	T
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 T

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter.

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 $192,730,733.

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

As of March 1, 2010, the registrant had 43,911,044 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

No documents are incorporated herein by reference.

NORTHERN OIL AND GAS, INC.

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EXPLANATORY NOTE

Northern Oil and Gas, Inc. is filing this Amendment No. 2 to its Annual Report on Form 10-K for the year ended December 31, 2009 filed with the Securities and Exchange Commission (the "SEC") on March 8, 2010, as amended by Amendment No. 1 to the Form 10-K filed with the SEC on April 30, 2010. Our Annual Report on Form 10-K and Amendment No. 1 to that Annual Report are collectively referred to as the "Original Filings". This Amendment No. 2 is being filed to enhance certain disclosures set forth in the Original Filings.

Except where specifically indicated, this Amendment No. 2 to Form 10-K does not reflect events occurring after the filing of the Original Filings or modify or update those disclosures affected by subsequent events. Consequently, all other information is unchanged and reflects the disclosures made at the time of the filing of the Original Filings. Except as expressly set forth in this Form 10-K/A, the Original Filings have not been amended, updated or otherwise modified.

PART I

Item 1. Business

Overview

Our company took its present form on March 20, 2007, when Northern Oil and Gas, Inc. ("Northern"), a Nevada corporation engaged in our company's 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 has been accounted for as a reverse merger. The financial statements presented in our company's December 31, 2006, Form 10-KSB report were the historical financial statements of Kentex Petroleum, Inc., the predecessor company. Additional material terms of the Merger are detailed in our company's Current Report on Form 8-K filed with the SEC on December 19, 2006. Following the Merger, our main business focus has been directed to oil and gas exploration and development. Unless specifically stated otherwise, our primary operations are now those formerly operated by Northern as well as other business activities since March 2007.

On March 17, 2008 our company received an approval letter to begin trading on the American Stock Exchange (the "AMEX"). Our common stock commenced trading on the AMEX on March 26, 2008 under the symbol "NOG." Our common stock commenced trading on the floor of the NYSE on the NYSE Amex Equities Market platform upon completion of NYSE Euronext's acquisition of the American Stock Exchange.

Business

We are a growth-oriented independent energy company engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties, and have focused our activities primarily on projects based in the Rocky Mountain Region of the United States, specifically the Bakken and Three Forks/Sanish formations within the Williston Basin. 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 began drilling for oil in the Williston Basin region in the fourth fiscal quarter of 2007. As of March 1, 2010, we owned working interests in 188 successful discoveries, consisting of 185 targeting the Bakken/Three Forks formation and three targeting a Red River structure.

As an exploration company, our business strategy is to identify and exploit repeatable and scalable resource plays that can be quickly developed and at low costs. We also intend to take advantage of our expertise in aggressive land acquisition 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 are focused on maintaining a low overhead structure. We believe we are in a position to most efficiently exploit and identify high production oil and 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 carefully pursue the acquisition of properties that fit our profile.

Reserves

We completed our initial reservoir engineering calculations in the first fiscal quarter of 2008 and recently completed our most current reservoir engineering calculation as of December 31, 2009. Our independent reservoir engineering firm did not calculate proved undeveloped reserves as of December 31, 2008, because we had not participated in a sufficient number wells to substantiate our proved undeveloped reserves at that time. As such, we cannot quantify the amount of proved undeveloped reserves converted to proved developed reserves during 2009.

We completed our initial calculation of proved undeveloped reserves as of December 31, 2009, which had the effect of increasing our total proved reserves. We substantially increased our proved reserves from December 31, 2008 to December 31, 2009, primarily as a result of increased drilling activity involving our acreage. We accrued approximately $22,655,438 of capital expenditures for drilling activities during the year ended December 31, 2009, which directly contributed to the increase in our proved developed reserves. Because we did not have an estimate of our proved undeveloped reserves as of December 31, 2008, our entire capital expenditures for drilling activities in 2009 contributed to the creation of proved developed reserves. No other expenditures materially contributed to creation of proved developed reserves in 2009. 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 year-end, we had completed drilling on approximately 10% of our Bakken prospective acreage inventory assuming 640-acre spacing units. The value of our reserves is calculated by determining the present value of estimated future revenues to be generated from the production of our proved reserves, net of estimated lease operating expenses, production taxes and future development costs. 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 accumulate historical production data for our wells, calculate historical lease operating expenses and differentials, update working interests and net revenue interests, obtain updated authorizations for expenditure (AFEs) from our operations department and obtain geological and geophysical information from operators. This data is forwarded to our third-party engineering firm for review and calculation. Our Chief Financial 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 beginning with the preparation of our December 31, 2008 reserve report. The selection of Ryder Scott was approved by our Audit Committee. Ryder Scott is one of the largest reservoir-evaluation consulting firms and evaluates oil and gas properties and independently certifies petroleum reserves quantities for various clients throughout the United States and internationally. Ryder Scott has substantial experience calculating the reserves of various other companies with operations targeting the Bakken and Three Forks formations and, as such, we believe Ryder Scott has sufficient experience to appropriately determine our reserves. Ryder Scott utilizes proprietary technology, systems and data to calculate our reserves commensurate with this experience.

The tables below summarize our estimated proved reserves as of December 31, 2009 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 Colorado Registered Engineering Firm (F-1580). Our primary contact at Ryder Scott is Richard J. Marshall P.E., Vice President. Mr. Marshall is a State of Colorado Licensed Professional Engineer (License #23260).

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

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

To estimate economically recoverable oil and 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 owned, 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, product prices 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 revenues therefrom and the actual costs related thereto could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency. See "Item 1A. Risk Factors – Estimates of 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 two separate reserve reports valuing our proved reserves at December 31, 2009. The reports value only our proved reserves and do not value our probable reserves or our possible reserves. Both tables account for straight-line pricing of crude oil and natural gas at constant prices over the expected life of our wells. Our "SEC Pricing Proved Reserves" were calculated using oil and gas price parameters established by current SEC guidelines and Financial Accounting Standard Board guidance. Our "Sensitivity Case Proved Reserves" were calculated using higher assumed values for crude oil and natural gas selected at our discretion to better reflect our current expectations because the SEC pricing parameters are significantly lower than current market prices and our average realized price per barrel at December 31, 2009. The Sensitivity Case Proved Reserves table provided below is intended to illustrate reserve sensitivities to the commodity prices. These sensitivity prices were selected because they are consistent with the prior SEC methodology utilizing year-end pricing. The "Sensitivity Case Proved Reserves" should not be confused with "SEC Pricing Proved Reserves" as outlined below and does not comply with SEC pricing assumptions, but does comply with all other definitions.

SEC Pricing Proved Reserves(1)

	Crude Oil (barrels)	Natural Gas (cubic feet)	Total (barrels of oil equivalent)(2)	Pre-Tax PV10% Value(3)
PDP Properties(4)	1,647,031	513,112	1,732,550	$37,784,555
PDNP Properties(5)	600,687	214,125	636,375	$12,795,237
PUD Properties(6)	3,567,861	1,033,686	3,740,141	$37,232,700
Total Proved Properties:	5,815,579	1,760,923	6,109,066	$87,812,492

Sensitivity Case Proved Reserves(1)

	Crude Oil (barrels)	Natural Gas (cubic feet)	Total (barrels of oil equivalent)(2)	Pre-Tax PV10% Value(3)
PDP Properties(4)	1,730,728	529,657	1,819,004	$54,303,781
PDNP Properties(5)	630,542	224,383	667,939	$19,378,670

PUD Properties(6)	7,447,783	3,508,210	8,032,485	$93,901,002
Total Proved Properties:	9,809,053	4,262,250	10,519,428	$167,583,453

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(1) The SEC Pricing Proved Reserves table above values oil and gas reserve quantities and related discounted future net cash flows as of December 31, 2009 assuming a constant realized price of $53.00 per barrel of crude oil and a constant realized price of $3.93 per 1,000 cubic feet (Mcf) of natural gas.
The Sensitivity Case Proved Reserves table above values oil and gas reserve quantities and related discounted future net cash flows as of December 31, 2009 assuming a constant realized price of $71.82 per barrel of crude oil and a constant realized price of $5.07 per 1,000 cubic feet (Mcf) of natural gas, which prices are consistent with prior SEC pricing methodology.
The Sensitivity Case Proved Reserves table is intended to illustrate reserve sensitivities to the commodity prices. These sensitivity prices were selected because they are consistent with the prior SEC methodology utilizing year-end pricing. The "Sensitivity Case Proved Reserves" should not be confused with "SEC Pricing Proved Reserves" as outlined above and does not comply with SEC pricing assumptions, but does comply with all other definitions.

The values presented in both tables above were calculated by Ryder Scott.

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

(4) "PDP" consists of our proved developed producing reserves.

(5) "PDNP" consists of our proved developed nonproducing reserves, awaiting completion.

(6) "PUD" consists of our proved undeveloped reserves present valued net of development cost.

Our December 31, 2009 reserve report includes an assessment of proven undeveloped locations, which includes approximately 93% of our undeveloped acreage. Our current North Dakota and Montana acreage position will allow us to drill approximately 162 net wells based on 640-acre spacing units with production from a single prospect. With 320-acre spacing units we have the ability to drill a total of approximately 578 net wells, including 255 net wells targeting the Bakken formation, 255 net wells targeting the Three Forks formation and 68 net wells targeting the Red River formation.

The tables above assume 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
Standardized Measure Reconciliation

Pre-tax Present Value of estimated future net revenues (Pre-tax PV10%)	$87,812,492
Future income taxes, discounted at 10%	(20,005,931)
Standardized measure of discounted future net cash flows	$67,806,561

The following table reconciles the Pre-tax PV10% value of our Sensitivity Case Proved Reserves to the standardized measure of discounted future net cash flows.

Sensitivity Case Proved Reserves Standardized Measure Reconciliation	
Pre-tax Present Value of estimated future net revenues (Pre-tax PV10%)	$167,583,453
Future income taxes, discounted at 10%	(50,995,503)
Standardized measure of discounted future net cash flows	$116,587,950

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

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

Recent Developments

During 2009, we continued to focus our operations on acquiring leaseholds and drilling exploratory and developmental wells in the Rocky Mountain Region of the United States, specifically the Williston Basin. We acquired an aggregate of 20,316 additional net mineral acres during 2009, primarily in Mountrail and Dunn Counties of North Dakota but also in Burke, Divide, McKenzie, Williams and other counties of North Dakota. As of December 31, 2009, we had participated in the completion of 176 gross wells with a 100% success rate in the Bakken and Three Forks formations. As of December 31, 2009, our principal assets included approximately 104,000 net acres located in the Williston Basin region of the northern United States and approximately 10,000 net acres located in Yates County, New York, as more fully described under the heading "Properties – Leasehold Properties" in Item 2 of this report.

During 2009, we continued to acquire interests in oil, gas and mineral leases with the intention of increasing our acreage positions in desired prospects. A complete discussion of our significant acquisitions during the past fiscal year is included under the heading "Properties – Recent Acreage Acquisitions" in Item 2 of this report.

Production Methods

We primarily engage in oil and 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. Prior to commencing drilling, our partners are required to provide all owners of oil, 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. In 2009, we participated in the drilling of all new wells that included any of our acreage. We will assess each drilling opportunity on a case-by-case basis going forward and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and 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 oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil production from our wells to appropriate pipelines 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 oil and is readily accepted into the pipeline infrastructure. The weighted average differential reported to us by our producers during the second half of 2009 was $8.57 per barrel below New York Mercantile Exchange (NYMEX) pricing. This differential represents the imbedded transportation costs in moving the oil from wellhead to refinery.

Competition

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

Our larger or integrated competitors may 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 oil and natural gas properties and bidding for exploratory prospects, because we have fewer financial and human resources than other companies in our industry. Should a larger and better financed company decide to directly compete with us, and be successful in its efforts, our business could be adversely affected.

Marketing and Customers

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

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners 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.

Principal Agreements Affecting Our Ordinary Business

We do not own any physical real estate, but, instead, our acreage is comprised of leasehold interests subject to the terms and provisions of lease agreements that provide our company the right to drill and maintain wells in specific geographic areas. All lease arrangements that comprise our acreage positions are established using industry-standard terms that have been established and used in the oil and 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 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," meaning the lease continues as long as oil is being produced. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production. Given the current pace of drilling in the Bakken play at this time, we do not believe lease expiration issues will materially affect our North Dakota position.

Governmental Regulation and Environmental Matters

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

Regulation of Oil and Natural Gas Production

Our oil and natural gas exploration, production and related operations, 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 oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations.

Environmental Matters

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

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;

- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and

- impose substantial liabilities for pollution resulting from its operations.

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

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

The Endangered Species Act (“ESA”) seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of the Act. 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 to significant expenses to modify our operations or could force our company to discontinue certain operations altogether.

Climate Change

Significant studies and research have been devoted to climate change and global warming, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production. 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 increase operating costs and demand for 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 eight full time employees. Our Chief Executive Officer—Michael Reger—and our Chief Financial Officer—Ryan Gilbertson—are responsible for all material policy-making decisions. They are assisted in the implementation of our company's business by our Vice President of Operations and our General Counsel. 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, assuming 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, particularly in the area of land services and reservoir engineering. 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 3,044 square feet leased pursuant to a five-year office lease agreement that commenced in February 2008. We believe our current office space is sufficient to meet our needs for the foreseeable future.

Financial Information about Segments and Geographic Areas

We have not segregated our operations into geographic areas given the fact that all of our production activities occur within the Williston Basin.

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 (formerly Form 10-KSB), quarterly reports on Form 10-Q (formerly Form 10-QSB), 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.

Item 2. Properties

Leasehold Properties

As of December 31, 2009, our principal assets included approximately 104,000 net acres located in the Williston Basin region of the northern United States and approximately 10,000 net acres located in Yates County, New York, more fully described as follows:

Approximately 30,400 net acres located in Mountrail County North Dakota, within and surrounding to the north south and west of the Parshall Field currently being developed by EOG Resources, Slawson Exploration Company, Inc. ("Slawson") and others to target the Bakken Shale;

Approximately 26,800 net acres located in Dunn County, North Dakota, in which we are targeting the Bakken Shale and Three Forks/Sanish formations;

Approximately 10,000 net acres located in Burke and Divide Counties of North Dakota, targeting the Bakken Shale and Three Forks/Sanish formations near significant drilling activities by Continental Resources;

Approximately 8,900 net acres located in McKenzie, Williams and Mercer Counties North Dakota, in which we are targeting the Bakken Shale;

Approximately 22,400 net acres located in Sheridan County, Montana, representing a stacked pay prospect over which we have significant proprietary 3-D seismic data;

Approximately 5,500 net acres located in Roosevelt and Richland Counties Montana, in which we are targeting the Bakken Shale; and

Approximately 10,000 net acres located in the “Finger Lakes” region of Yates County, New York, in which we are targeting natural gas production from the Trenton/Black River, Marcellus and Queenstown-Medina formations.

We believe the Bakken formation represents one of the most oil rich, rapidly developing and exciting plays in the Continental United States. We commenced drilling on the Bakken properties in late 2007 and increased drilling activities quarter-over-quarter throughout 2008 and 2009.

Recent Acreage Acquisitions

In 2009, we acquired leasehold interests covering an aggregate of 20,316 net mineral acres in our key prospect areas. The discussion that follows summarizes these acquisitions.

On May 22, 2009, we entered into an agreement with Slawson pursuant to which we acquired certain North Dakota Bakken assets from Windsor Bakken LLC as part of a syndicate led by Slawson. In the transaction we acquired leases covering 3,323 net mineral acres.

On November 3, 2009, we acquired 24 high working interest sections comprising approximately 11,274 net acres located in western McKenzie and Williams Counties of North Dakota. We acquired a 50% participation interest in these properties with Slawson and will participate in drilling on a heads-up basis. These properties are proximal to several recent high-rate producing wells. We expect to begin drilling these properties in early 2011.

On November 13, 2009, we entered into an agreement with Slawson pursuant to which we acquired a 20% participation interest in Slawson's Big Sky Project in Richland County, Montana. The project area encompasses 11,586 net acres of leases.

On November 17, 2009, we entered into an Exploration and Development Agreement with Area of Mutual Interest with Slawson pursuant to which we acquired a 30% participation interest in Slawson's Anvil Project in Williams County, North Dakota and Roosevelt County, Montana. The project area encompasses 12,500 net acres of leases.

In addition to acquiring acreage through large block acquisitions, we have organically acquired approximately 5,289 net mineral acres in our key prospect areas.

Developed and Undeveloped Acreage

The following table summarizes our estimated gross and net developed and undeveloped acreage by county at December 31, 2009. Net acreage represents our percentage ownership of gross acreage. The following table does not include acreage in which our interest is limited to royalty and overriding royalty interests.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	44,076	7,433	396,685	68,084	440,761	75,516
Montana	1,046	479	32,514	27,459	33,560	27,938
New York	0	0	10,000	10,000	10,000	10,000
Total:	45,122	7,912	439,199	105,542	484,321	113,454

As of December 31, 2009, approximately 7,912 net acres have been developed and approximately 105,542 net acres are undeveloped. As of December 31, 2009, leases covering approximately 24,176 net acres in Sheridan County, Montana, are scheduled to expire during the 2010 calendar year. None of the leases expiring during the 2010 calendar year comprise a majority ownership of any single drilling unit. The Company believes that the 24,176 net acres in Sheridan County, Montana scheduled to expire during the 2010 calendar year do not represent a material percentage of our total dollar investment into our overall acreage position. Since inception the Company has deployed approximately $51 million into its total net acres through December 31, 2009. The Sheridan County, Montana acreage represents less than 5% of the Company's total investment on acreage acquisitions from inception through December 31, 2009. In addition, none of the acreage was included when calculating the Company's reserves at December 31, 2008 or December 31, 2009. As such, we do not consider the expiration of this undeveloped acreage to be material.

Production History

The following table presents information about our produced oil and gas volumes during each fiscal quarter in 2009 and the year ended December 31, 2009. The table below does not provide any information for our fiscal year ended December 31, 2007 because we did not commence drilling activities until the fourth fiscal quarter of 2007 and did not receive payment or recognize revenue from crude oil or natural gas sales in 2007. As of December 31, 2009, we were selling oil and natural gas from a total of 179 gross wells, all of which are located within the Williston Basin. As of December 31, 2008, we were selling oil and natural gas from a total of 36 gross wells. All data presented below is derived from accrued revenue and production volumes for the relevant period indicated.

	Year Ended December 31,	
	2009	2008
Net Production:		
Oil (Bbl)	274,328	50,880
Natural Gas (Mcf)	47,305	3,969
Barrel of Oil Equivalent (BOE)	282,212	51,542
Average Sales Prices:		
Oil (per Bbl)	$60.45	$75.63
Effect of oil hedges on average price (per Bbl)	$(3.60)	$15.31
Oil net of hedging (per Bbl)	$56.85	$90.94
Natural Gas (per Mcf)	$3.81	$8.19
Effect of natural gas hedges on average price (per Mcf)	--	--
Natural gas net of hedging (per Mcf)	$3.81	$8.19
Average Production Costs:		
Oil (per Bbl)	$2.67	$1.37
Natural Gas (per Mcf)	$0.19	$0.32
Barrel of Oil Equivalent (BOE)	$2.63	$1.38

Depletion of oil and natural gas properties

Our depletion expense is driven by many factors including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. The following table presents our depletion expenses during 2008 and 2009.

	Year Ended December 31,	
	2009	2008 (adjusted)
Depletion of oil and natural gas properties	$ 4,250,983	$ 677,915 *

* See Note 2 to the financial statements accompanying this report.

Drilling and Other Exploratory and Development Activities

The following tables summarize gross and net productive and non productive oil wells by state at December 31, 2009, 2008 and 2007. A net well represents our percentage ownership of a gross well. No wells have been permitted or drilled on any of our Yates County, New York acreage. The following tables do not include wells in which our interest is limited to royalty and overriding royalty interests. The following tables also do not include wells which 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. All wells drilled to-date in North Dakota are classified as development wells, meaning we have not drilled any exploratory wells in North Dakota. As of December 31, 2009, we have had 100% success rate in our North Dakota Bakken and Three Forks wells. All productive exploratory and developmental wells set forth below in North Dakota and Montana for the year ending December 31, 2009, 2008 and 2007, are included in our 179 gross productive oil wells as of December 31, 2009.

North Dakota

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Natural gas	0	0	0	0	0	0
Oil	139	6.63	29	1.38	2	0.09
Non-productive	0	0	0	0	0	0
Total Development Wells	139	6.63	29	1.38	2	0.09

Montana

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Natural gas	0	0	0	0	0	0
Oil	1	0.23	2	0.5	0	0
Non-productive	0	0	0	0	1	0.06
Total Exploratory Wells:	1	0.23	2	0.5	1	0.06
Development Wells:						
Natural gas	0	0	0	0	0	0
Oil	5	0.23	1	0.07	0	0
Non-productive	0	0	0	0	0	0
Total Development Wells:	5	0.23	1	0.07	0	0
Total Productive Development and Exploratory Wells:	6	0.46	3	0.12	0	0

As of December 31, 2009, we had 13 Bakken or Three Forks wells drilling in the Williston Basin, representing an aggregate of 0.52 net wells. We also had 15 Bakken or Three Forks wells in the Williston Basin awaiting completion, in the process of completion or awaiting flowback subsequent to fracture stimulation, representing an aggregate of 1.03 net wells.

Dry Holes

As of December 31, 2009, we have participated in the completion of 176 gross wells with a 100% success rate in the Bakken and Three Forks formations. In the second quarter of 2007, we participated in the Teigen Trust #9-13 with a 6.25% working interest, a well identified, proposed and drilled by Kodiak Oil and Gas, Inc. The well was intended to target the Red River formation, but produced a dry hole. This is the only dry hole in our company’s history.

Research and Development

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

Reserves

We completed our most recent reservoir engineering calculation as of December 31, 2009. Tables summarizing the results of our most recent reserve report are included under the heading "Business – Reserves" in Item 1 of this report. A complete discussion of our proved reserves is set forth in "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 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. A discussion of our past financial results before March 20, 2007 is not pertinent to the business plan of our company on a going forward basis, due to the change in our business which occurred upon consummation of the merger on March 20, 2007.

Overview and Outlook

We are an oil and gas exploration and production company. Our properties are located in Montana, North Dakota and New York. Our corporate strategy is to build shareholder value through the development and acquisition of oil and gas assets that exhibit economically producible hydrocarbons.

As of March 1, 2010, we controlled the rights to mineral leases covering approximately 121,800 net acres of land. 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. In order to accomplish our objectives we will need to 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; and
- Continue to manage our financial obligations to access the appropriate capital needed to develop our position of primarily undrilled acreage.

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, 2009	2008 (adjusted)*	2007
Net Production:			
Oil (Bbl)	274,328	50,880	--
Natural Gas (Mcf)	47,305	3,969	--
Net Sales:			
Oil Sales	$ 14,977,556	$ 3,510,596	--
Natural Gas	194,268	32,397	--
Gain (Loss) on Settled Derivatives	(624,541)	778,885	--
Mark-to-Market of Derivative Instruments	(363,414)		
Other Revenue	37,630		
Total Revenues	$ 14,221,499	$ 4,321,879	--
Average Sales Prices:			
Oil (per Bbl)	$ 60.45	$ 75.63	--
Effect of Oil Hedges on Average Price (per Bbl)	$ (3.60)	$ 15.31	--
Oil Net of Hedging (per Bbl)	$ 56.85	$ 90.94	--
Natural Gas (per Mcf)	$ 3.81	$ 8.19	--
Effect of Natural Gas Hedges on Average Price (per Mcf)	--	--	--
Natural gas net of hedging (per Mcf)	$ 3.81	$ 8.19	--
Operating Expenses:			
Production Expenses	$ 754,976	$ 70,954	--
Production Taxes	$ 1,300,373	$ 203,182	--
General and Administrative Expense (Including Share Based Compensation)	$ 3,686,330	$ 2,091,289	$ 4,509,743
Depletion of Oil and Gas Properties*	$ 4,250,983	$ 677,915	--

* See Note 2 to the financial statements accompanying this report.

Results of Operations for the periods ended December 31, 2008 and December 31, 2009.

During 2008 and 2009 we significantly increased our drilling activities, generated income and achieved net earnings for both the 2008 and 2009 fiscal years. To-date, we have developed approximately seven percent of our total drillable acreage inventory (assuming one well per 640-acre spacing unit) and we expect to continue to add substantial volumes of production on a quarter-over-quarter basis going forward into the foreseeable future.

As of December 31, 2009, we had established production from 179 gross (9.19 net) wells in which we hold working interests, 36 gross (2.04 net) wells of which had established production as of December 31, 2008. Our production at December 31, 2009 approximated 1,508 barrels of oil per day, compared to approximately 460 barrels of oil per day as of December 31, 2008. Our production increased to 1,986 barrels of oil per day as of March 1, 2010.

We drilled with a 100% success rate in 2008 and 2009 with 176 Bakken or Three Forks wells completed or completing. We also had three successful Red River discoveries at December 31, 2009. As of March 1, 2010, we expect to participate in the drilling of approximately 200 gross (15 net) wells in 2010.

Our revenues, costs and net income increased in 2009 compared to 2008 as we continued our development plans and significantly increased our production. Revenues for the twelve-month period ended December 31, 2009 were $14,221,499, compared to $4,321,879 for the twelve-month period ended December 31, 2008 primarily due to increases in production.

Adjusted total cash and non-cash expenses (including production expenses, production taxes, general and administrative expenses, director fees, depletion expenses, depreciation and amortization expenses) for the twelve-month period ended December 31, 2009 were $10,092,538 and for the twelve-month period ended December 31, 2008 were $3,111,430. Of this amount in 2009, approximately $1,233,507 consisted of non-cash expense related to the issuance of restricted stock and an additional $4,250,983 consisted of non-cash depletion expenses. Depletion expenses for the twelve-month period ended December 31, 2008 were $677,915.

We had net income of $2,798,952 (representing approximately $0.08 per basic share) for the twelve-month period ended December 31, 2009 compared to net income of $2,424,340 (representing approximately $0.08 per basic share) for the twelve-month period ended December 31, 2008.

Results of Operations for the periods ended December 31, 2007 and December 31, 2008.

Our first well commenced drilling in the fourth quarter of 2007, and we did not realize revenue from that well until the first quarter of 2008. During 2008 we significantly increased our drilling activities compared to 2007, generated income and achieved net earnings in the third and fourth quarters of 2008 and for the 2008 fiscal year as a whole. Our production at December 31, 2008 approximated 460 barrels of oil per day. This compares to approximately 100 barrels of oil per day as of December 31, 2007.

Revenues for the twelve-month period ended December 31, 2008 were $4,321,879, compared to no revenues for the twelve-month period ended December 31, 2007. Our expenses in fiscal years 2006 and 2007 consisted principally of general and administrative costs. Our costs increased moderately as we proceeded with our development plans in 2008. Total expenses for the twelve-month period ended December 31, 2008 were $3,111,430 and for the twelve-month period ended December 31, 2007 were $4,513,189. We had net income of $2,424,340 (representing approximately $0.08 per basic share) for the twelve-month period ended December 31, 2008, compared to a net loss of $4,305,293 for the twelve-month period ended December 31, 2007.

Operation Plan

We expect to drill approximately 15 net wells in 2010 with drilling capital expenditures approximating $67.5 million. The 2010 wells are expected to target both the Bakken and Three Forks formations. Drilling capital expenditures are expected to increase in 2010 compared to previously published guidance due to the continued success of longer laterals and additional fractional stimulation stages. We currently expect to drill wells during 2010 at an average completed cost of $4.5 million per well. Based on evolving conditions in the field, we expect to deploy approximately $10 million towards further strategic acreage acquisitions during 2010. We expect to fund all 2010 commitments using cash-on-hand, cash flow and our currently undrawn credit facility.

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 oil and gas; (iii) the market price for oil and 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 oil and 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.

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to meet potential cash requirements. We have historically met our capital requirements through the issuance of common stock and by short term borrowings. In the future, we anticipate we will be able to provide the necessary liquidity by the revenues generated from the sales of our oil and gas reserves in our existing properties, however, if we do not generate sufficient sales revenues we will continue to finance our operations through equity and/or debt financings.

The following table summarizes total current assets, total current liabilities and working capital at December 31, 2009.

Current Assets	$ 42,017,813
Current Liabilities	$ 8,910,256
Working Capital	$ 33,107,557

CIT Capital USA, Inc. Credit Facility

On February 27, 2009, we completed the closing of a revolving credit facility with CIT that provides up to a maximum principal amount of $25 million of working capital for exploration and production operations (the "Credit Facility"). The borrowing base of funds available under the Credit Facility will be redetermined semi-annually based upon the net present value, discounted at 10% per annum, of the future net revenues expected to accrue from our interests in proved reserves estimated to be produced from our oil and gas properties. $16 million of financing is currently available under the Credit Facility. An additional $9 million of financing could become available upon subsequent borrowing base redeterminations based on the deployment of funds from the Credit Facility. The Credit Facility terminates on February 27, 2012. As of December 31, 2009, we had no borrowings outstanding under the Credit Facility.

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 offering rate (LIBOR) will be outstanding for a period of one, three or six months (as designated by us) and bear interest at a rate equal to 5.50% over the one-month, three-month or six-month LIBOR rate to be no less than 2.50%. Any borrowings not designated as being based upon LIBOR will have no specified term and generally will bear interest at a rate equal to 4.50% over the greater of (a) the current three-month LIBOR rate plus 1.0% or (b) the current prime rate as published by JP Morgan Chase Bank, N.A. We have the option to designate either pricing mechanism. 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 loan 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 applicable interest rate increases under the Credit Facility and the lenders may accelerate payments under the Credit Facility, or call all obligations due under certain circumstances, upon an event of default. The Credit Facility references various events constituting a default on the Credit Facility, including, but not limited to, failure to pay interest on any loan under the Credit Facility, any material violation of any representation or warranty under the Credit Agreement in connection with the Credit Facility, failure to observe or perform certain covenants, conditions or agreements under the Credit Facility, a change in control of our company, default under any other material indebtedness we might have, bankruptcy and similar proceedings and failure to pay disbursements from lines of credit issued under the Credit Facility.

The Credit Facility requires that we enter into a swap agreement with Macquarie Bank Limited ("Macquarie") to hedge production over the 36-month term of the Credit Facility. We have strategically entered into constant priced swap arrangements with Macquarie since inception of the Credit Facility to hedge our expected production. A full discussion of our current swap arrangements is set forth in "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk" in Item 7A of this report.

All of our obligations under the Credit Facility and the swap agreements with Macquarie are secured by a first priority security interest in any and all of our assets pursuant to the terms of a Guaranty and Collateral Agreement and perfected by a mortgage, notice of pledge and security and similar documents.

Follow-On Equity Offerings

On June 30, 2009, we completed a follow-on equity offering pursuant to which we sold 2.25 million shares of common stock to various institutional investors for $6.00 per share, resulting in gross proceeds of $13.5 million. Net proceeds to our company following deduction of agency fees and expenses were approximately $12.7 million and were used to repay outstanding borrowings under our Credit Facility, primarily including borrowings incurred in connection with our acquisition of North Dakota Bakken assets from Windsor Bakken LLC. C.K. Cooper & Company acted as lead placement agent for the offering.

On November 4, 2009, we completed an additional follow-on equity offering pursuant to which we sold 6.5 million shares of common stock to various institutional investors for $9.12 per share, resulting in gross proceeds of $59.3 million. Net proceeds to our company following deduction of agency fees and expenses were approximately $56.3 and were used to repay outstanding borrowings under our Credit Facility, pursue acquisition opportunities and for other working capital purposes. Canaccord Adams Inc. acted as lead placement agent for the offering. FIG Partners, LLC acted as co-placement agent for the offering.

Satisfaction of Our Cash Obligations for the Next 12 Months

With the addition of equity capital during 2009 and our Credit Facility, we believe we have sufficient capital to meet our drilling commitments and expected general and administrative expenses for the next twelve months at a minimum. Nonetheless, any strategic acquisition of assets may require us to access the capital markets at some point in 2010. We may also choose to access the equity capital markets rather than 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. Given our non-leveraged asset base and anticipated growing cash flows, we believe we are in a position to take advantage of any appropriately priced sales that may occur. 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, the Credit Facility and anticipated funds from operations may not be sufficient to sustain continued acreage acquisition. 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 stockholders.

Though we achieved profitability in 2008 and remained profitable throughout 2009, 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 oil and 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 and marketing strategy, continue to develop and upgrade technology and products, 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 oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Contractual Obligations and Commitments

As of December 31, 2009, we did not have any material long-term debt obligations, capital lease obligations, operating lease obligations or purchase obligations requiring future payments other than our office lease that expires on January 31, 2013, and outstanding promissory notes issued to our executive officers. The following table illustrates our contractual obligations as of December 31, 2009.

		Payment due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Office Lease(1)	$462,474	$148,151	$314,323	$--	--
Note Payable to Michael L. Reger(2)	$250,000	$--	$250,000	$--	--
Note Payable to Ryan R. Gilbertson(2)	$250,000	$--	$250,000	$--	--
Automobile Leases(3)	$61,116	$41,372	$19,744	--	--
	$1,023,590	$189,523	$834,067	$--	--

(1) Our office lease commenced on February 1, 2008 and continues for a period of five years.

(2) In February 2009, our Audit Committee and the Compensation Committee approved the issuance of $250,000 principal amount non-negotiable, unsecured subordinated promissory notes to both Michael Reger – our Chief Executive Officer – and Ryan Gilbertson – our Chief Financial Officer – in lieu of paying cash bonuses earned in 2008. The notes bear interest at a rate of 12% per annum and are subordinate to any secured debt of our company. Our Credit Facility now limits our ability to make interest and principal payments on the notes. All unpaid principal and interest on the notes are due and payable in full in a single lump sum on March 8, 2013.

(3) In July 2007, we entered into automobile leases for vehicles utilized by two of our employees, which expire in July, 2010. In September 2008 we entered into automobile leases for vehicles utilized by two additional employees, which expire in September, 2011.

Product Research and Development

We do not anticipate performing any significant product 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 consolidated financial statements in accordance with generally accepted accounting principles (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 U.S. GAAP requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our estimates of our proved oil and natural gas reserves, future development costs, estimates relating to certain oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of certain investments, and deferred income taxes are the most critical to our financial statements.

Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

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

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

Oil and Natural Gas Property

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

We utilize the full cost method of accounting to account for our oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for oil and natural gas investments. The primary difference between these two methods is the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unevaluated 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 unevaluated 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, 2009, our average depletion expense per unit of production was $15.06 per BOE. A 10% decrease in our estimated net proved reserves at December 31, 2009 would result in a $1.60 per BOE increase in our per unit depletion expense and a $450,000 decrease in our pre-tax net income.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on period-end oil and natural gas prices) of the estimated future net cash flows from our proved oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a capitalized ceiling impairment. Such costs would be charged to operations as a reduction of the carrying value of oil and natural gas properties. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or estimations of our proved reserves are substantially reduced. A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. The risk that we will experience a ceiling test writedown increases when oil and gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves. As of December 31, 2009 the Company has 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.

Asset Retirement Obligations

We have significant obligations to plug and abandon our oil and natural gas wells and related equipment. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. The related asset value is increased by the same amount. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. Additionally, increases in the discounted asset retirement liability resulting from the passage of time are reported as accretion of discount on asset retirement obligations expense on our Statement of Operations.

Estimating future asset retirement obligations requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments, which include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of our existing asset retirement obligation liability, a corresponding adjustment will be made to the carrying cost of the related asset.

Income Taxes

Deferred tax assets are recognized for temporary differences in financial statement and tax basis amounts that will result in deductible amounts and carry-forwards in future years. Deferred tax liabilities are recognized for temporary differences that will result in taxable amounts in future years. Deferred tax assets and liabilities are measured using enacted tax law and tax rate(s) for the year in which we expect the temporary differences to be deducted or settled.

The effect of a change in tax law or rates on the valuation of deferred tax assets and liabilities is recognized in income in the period of enactment. 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. Significant future taxable income would be required to realize this net tax asset.

Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income, and changes in stockholder ownership that would trigger limits on use of net operating losses under Internal Revenue Code Section 382.

Revenue Recognition

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

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

We recognize revenue from the sale of natural gas using the entitlements method of accounting. Under this method, we recognize revenue based on our entitled ownership percentage of sales of natural gas delivered to purchasers. Gas imbalances occur when we sell more or less than our entitled ownership percentage of total natural gas production. When we receive less than our entitled share, a receivable is recorded. When we receive more than our entitled share, a liability is recorded.

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

Derivative Instruments and Hedging Activities

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

Derivatives, historically, are recorded on the balance sheet at fair value and changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of hedge transaction. The Company’s derivatives historically consist primarily of cash flow hedge transactions in which the Company is 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 other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedges was reflected in current period earnings as gain or loss from derivative. 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.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and in addition, the Company has elected not to designate any subsequent derivative contracts as accounting hedges under FASB ASC 815-20-25. 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 and unrealized gains or losses are recorded on the statement of operations. We elected to include all derivative settlement and unrealized gains (losses) within revenues.

New Accounting Pronouncements

In March 2008, the FASB issued FASB ASC 815-10-15 (Prior authoritative literature, FASB Statement 161, Disclosures About Derivative Instruments and Hedging Activities). FASB ASC 815-10-15 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity's financial position, financial performance, and cash flows. FASB ASC 815-10-15 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. Pursuant to the transition provisions of the Statement, the Company adopted FASB ASC 815-10-15 on January 1, 2009. The required disclosures are presented in Note 15 on a prospective basis. This Statement does not impact the financial results as it is disclosure-only in nature.

In April 2009, the FASB issued FASB ASC 270-10-05 (Prior authoritative literature: APB 28-1, Interim Disclosures About Fair Value of Financial Instruments). FASB ASC 270-10-05 amends FASB ASC 825-10-50 (Prior authoritative literature: FASB Statement 107, Disclosures About Fair Value of Financial Instruments) to require an entity to provide disclosures about fair value of financial instruments in interim financial information. FASB ASC 270-10-05 is to be applied prospectively and is effective for interim and annual periods ending after June 15, 2009 with early adoption permitted for periods ending after March 15, 2009. The required disclosures are presented in Note 13 on a prospective basis.

In February 2008, the FASB issued FASB ASC 820-10-65-1 (Prior authoritative literature: FSP FAS 157-2/Statement 157, Effective Date of FASB Statement No. 157). FASB ASC 820-10-65-1 delayed the effective date for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of the provisions of FASB ASC 820-10-65-1 related to nonfinancial assets and nonfinancial liabilities on January 1, 2009 did not have a material impact on the Financial Statements. See Note 13 for FASB ASC 820-10-65-1 disclosures.

In April 2009, the FASB issued FASB ASC 820-10-65-4 (Prior authoritative literature: FASB Statement 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly). FASB ASC 820-10-65-4 provides additional guidance in estimating fair value, when the volume and level of transaction activity for an asset or liability have significantly decreased in relation to normal market activity for the asset or liability. FASB ASC 820-10-65-4 also provides additional guidance on circumstances that may indicate a transaction is not orderly. FASB ASC 820-10-65-4 is effective for interim periods ending after June 15, 2009, and the Company has adopted its provisions during second quarter 2009. FASB ASC 820-10-65-4 did not have a significant impact on the Company's financial position, results of operations, cash flows, or disclosures.

In April 2009, the FASB issued FASB ASC 320-10-65 (Prior authoritative literature: FSP FAS 115-2/124-2, Recognition and Presentation of Other-Than-Temporary Impairments). The guidance applies to investments in debt securities for which other-than-temporary impairments may be recorded. If an entity's management asserts that it does not have the intent to sell a debt security and it is more likely than not that it will not have to sell the security before recovery of its cost basis, then an entity may separate other-than-temporary impairments into two components: 1) the amount related to credit losses (recorded in earnings), and 2) all other amounts (recorded in other comprehensive income). This ASC is to be applied prospectively and is effective for interim and annual periods ending after June 15, 2009 with early adoption permitted for periods ending after March 15, 2009. The adoption of the provisions of this ASC in the second quarter 2009 did not have a material impact on the Financial Statements.

In June 2009, the FASB issued FASB ASC 860-10-05 (Prior authoritative literature: FASB Statement 166, Accounting for Transfers of Financial Assets). FASB ASC 860-10-05 is effective for fiscal years beginning after November 15, 2009. The Company is currently assessing the impact of FASB ASC 860-10-05 on its financial position and results of operations.

In June 2009, the FASB issued FASB ASC 810-10-25 (Prior authoritative literature: FASB Statement 167-Amendment to FIN 46(R), Consolidation of Variable Entities). FASB ASC 810-10-25 eliminates the quantitative approach previously required for determining the primary beneficiary of a variable interest entity and requires a qualitative analysis to determine whether an enterprise's variable interest gives it a controlling financial interest in a variable interest entity. FASB ASC 810-10-25 contains certain guidance for determining whether an entity is a variable interest entity. This statement also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. FASB ASC 810-10-25 will be effective as of the beginning of the Company's 2010 fiscal year. The Company is currently evaluating the impact of the adoption of FASB ASC 810-10-25.

In June 2009, the FASB issued FASB ASC 105-10-65 (Prior authoritative literature: FASB Statement 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles). Under FASB ASC 105-10-65, the FASB Accounting Standards Codification ™ (the "Codification") becomes the exclusive source of authoritative U.S. generally accepted accounting principles ("U.S. GAAP") recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The Codification will supersede all then-existing non-SEC accounting and reporting standards, with the exception of certain non-SEC accounting literature which will become nonauthoritative. FASB ASC 105-10-65 is effective for the Company's 2009 third fiscal quarter. The adoption of FASB ASC 105-10-65 did not have a material impact on the Company's Financial Statements. All references to U.S. GAAP provided in the notes to the Financial Statements have been updated to conform to the Codification.

In October 2009, the FASB issued ASU No. 200-13, Revenue Recognition – Multiple Deliverable Revenue Arrangements ("ASU 2009-13"). ASU 2009-13 updates the existing multiple-element revenue arrangements guidance currently included in FASB ASC 605-25. The revised guidance provides for two significant changes to the existing multiple-element revenue arrangements guidance. The first change relates to the determination of when the individual deliverables included in a multiple-element arrangement may be treated as separate units of accounting. This change will result in the requirement to separate more deliverables within an arrangement, ultimately leading to less revenue deferral. The second change modifies the manner in which the transaction consideration is allocated across the separately identified deliverables. Together, these changes will result in earlier recognition of revenue and related costs for multiple-element arrangements than under previous guidance. This guidance expands the disclosures required for multiple-element revenue arrangements effective for interim and annual reporting periods beginning after December 15, 2009. The Company is currently evaluating the potential impact, if any, of this guidance on its financial statements.

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.

PART III

Item 11. Executive Compensation

The following discussion of executive compensation addresses the material compensation awarded to our four named executive officers, including the following individuals:

Michael L. Reger	Chief Executive Officer, Chairman of the Board and Director
Ryan R. Gilbertson	President and Director
Chad D. Winter	Chief Financial Officer
James R. Sankovitz	Chief Operations Officer, General Counsel and Secretary

Summary Compensation Table

The table below shows compensation for our named executive officers for services in all capacities to our company during fiscal years 2007, 2008 and 2009. Information provided for fiscal year 2007 reflects compensation paid by our predecessor—Northern Oil and Gas, Inc. Compensation, as reflected in this table and the tables which follow, is presented on the basis of rules of the SEC and does not, in the case of certain stock-based awards or accruals, necessarily represent the amount of compensation realized or which may be realized in the future. For more information regarding our salary policies and executive compensation plans, please review the information under the caption "Compensation Committee Report."

Name and Principal Position(1)	Year	Salary ($)	Bonus ($)(2)	Stock Awards ($)(3)	Option Awards ($)(4)	Non-Equity Incentive Plan Compensation ($)(5)	All Other Compensation ($)(6)(7)	Total Compensation ($)
Michael L. Reger	2007	–	120,000	–	–	–	1,367	121,367
Chief	2008	185,000	100,000	–	–	370,000	155,833	810,833
Executive Officer and Chairman of the Board	2009	285,000	570,000	1,455,000 (8)	–	–	50,186	2,360,186
Ryan R. Gilbertson	2007	–	120,000	–	–	–	1,955	121,955
	2008	185,000	100,000	–	–	370,000	156,964	811,964
President	2009	285,000	570,000	1,455,000 (9)	–	–	58,782	2,368,782

Chad D. Winter	2007	–	–	388,500	(10)	163,200	(11)	–	–	551,700
Chief	2008	105,000	–	–		–		–	677	105,677
Financial Officer	2009	155,000	–	441,750	(12)	–		–	34,478	631,228
James R. Sankovitz	2008	100,000	–	140,500	(13)	–		–	1,802	207,177
Chief Operating Officer, General Counsel & Secretary	2009	155,000	–	441,750	(14)	–		–	39,613	636,363

(1) Mr. Reger joined our company as Chief Executive Officer, Chairman of the Board and Secretary and Mr. Gilbertson joined us as Chief Financial Officer and a director on March 20, 2007. Mr. Winter joined our company in November 2007 and Mr. Sankovitz joined our company in March 2008. Mr. Reger, Mr. Gilbertson and Mr. Winter were not paid any salary during the fiscal year ended December 31, 2007.

(2) The amounts reported for Messrs. Reger and Gilbertson represent $120,000 year-end cash bonuses in 2007, $100,000 signing bonuses upon execution of employment agreements in 2008 and $570,000 year-end cash bonuses in 2009.

(3) Valuation of awards based on the grant date fair value of those awards computed in accordance with FASB ASC Topic 718 utilizing assumptions discussed in note 8 to our consolidated financial statements for the fiscal year ended December 31, 2009.

(4) Valuation of awards based on the grant date fair value of those awards computed in accordance with FASB ASC Topic 718 utilizing assumptions discussed in note 8 to our consolidated financial statements for the fiscal year ended December 31, 2009.

(5) For 2008, the amounts reported for Messrs. Reger and Gilbertson include a $370,000 year-end bonus based upon achievement of performance objectives and approved by the Compensation Committee but paid through issuance of promissory notes in lieu of cash bonus.

(6) For 2008, the amounts reported for Messrs. Reger and Gilbertson include $153,735 accrued by our company as an additional bonus to pay tax obligations associated with year-end bonuses in consideration of their willingness to accept such bonuses in the form of unsecured notes rather than cash.

(7) The amounts reported consist of the following for 2009:

Form of All Other Compensation	Michael L. Reger	Ryan R. Gilbertson	Chad D. Winter	James R. Sankovitz
Personal use of company-leased vehicles ($)	7,202	7,032	9,113	11,977
401(k) contributions by the Company ($)	16,500	16,500	16,500	16,500
Reimbursement of meal, entertainment and personal expenses ($)	10,698	5,274	1,445	2,876
Tax Gross-ups ($)	15,786	29,976	7,420	8,260
Total ($)	50,186	58,782	34,478	39,613

(8) Reflects the grant date fair value of 50,000 shares of common stock and 100,000 shares of restricted common stock, granted to Mr. Reger on December 7, 2009.

(9) Reflects the grant date fair value of 50,000 shares of common stock and 100,000 shares of restricted common stock, granted to Mr. Gilbertson on December 7, 2009.

(10) Reflects the grant date fair value of 75,000 shares of common stock granted to Mr. Winter upon the commencement of his employment in November 2007.

(11) Reflects the grant date fair value of options to purchase 60,000 shares of common stock granted to Mr. Winter upon the commencement of his employment in November 2007.

(12) Includes (i) $ 213,000, which is the grant date fair value of 45,000 shares of common stock and 30,000 shares of restricted common stock, granted to Mr. Winter on February 23, 2009 and (ii) $228,750, which is the grant date fair value of 25,000 shares of common stock granted to Mr. Winter on November 30, 2009.

(13) Reflects the grant date fair value of 20,000 shares of restricted common stock granted to Mr. Sankovitz upon the commencement of his employment in March 2008.

(14) Includes (i) $213,000, which is the grant date fair value of 45,000 shares of common stock and 30,000 shares of restricted common stock, granted to Mr. Sankovitz on February 23, 2009 and (ii) $ 228,750, which is the grant date fair value of 25,000 shares of common stock granted to Mr. Sankovitz on November 30, 2009.

Compensation Discussion and Analysis

Our Compensation Committee is responsible for establishing director and executive officer compensation, policies and programs to insure that they are consistent with our compensation philosophy and corporate governance guidelines. The Compensation Committee is authorized to make plan awards to our employees to recognize individual and company-wide achievements as the Committee deems appropriate. Our Compensation Committee has annually reviewed and approved base salary and incentive compensation levels, employment agreements and benefits of executive officers and other key executives.

We have implemented a compensation program that is designed to reward our management for maximizing stockholder value and ensuring the long-term stability of our company. Our compensation program is intended to reward individual accomplishments, team success and corporate results. It also recognizes the varying responsibilities and contributions of each employee and is intended to foster an ownership mentality among our management team.

Stock-Based Incentives

We have traditionally utilized stock incentives as a means to align the interests of our management with the interests of our stockholders and motivate our management to enhance stockholder value. Stock issuances to-date have been designed to serve as both short-term rewards and long-term incentives. As a result, each of our named executive officers holds a significant number of shares of our outstanding common stock.

Year-End Compensation Decisions

Near the end of the 2009, the Compensation Committee met on multiple occasions to consider the performance of our named executive officers and make year-end compensation decisions. In evaluating the performance of our named executive officers, the Committee primarily focused on the accomplishments and overall performance of the Company during 2009. Notable accomplishments in 2009 that the Compensation Committee took into account were the closing of a $25 million credit facility with CIT; the raising of over $70 million in equity capital at accretive levels; the substantial increase in production and revenues from 2008 to 2009; the efficient expansion of the company's acreage position throughout 2009; and the realization of almost a 400% stock appreciation from the lows of March 2009.

The Compensation Committee also examined the compensation policies and practices of numerous exploration and production companies which it deemed to be similar to our company. The companies examined included Kodiak Oil & Gas Corp., Double Eagle Petroleum Co., Gasco Energy, Inc., Gastar Exploration Ltd., Union Drilling, Inc., Bronco Drilling Company, Venoco Inc. and FX Energy, Inc. The Compensation Committee used this information in determining 2009 bonus and 2010 base salary amounts for our management.

2009 Cash Bonuses

On November 30, 2009, the Compensation Committee approved the payment of a $570,000 cash bonus to each of Mr. Reger and Mr. Gilbertson, in recognition of their contributions to the Company and the significant accomplishments of the Company during 2009. The total bonus amount was determined by the Compensation Committee on a post hoc basis based on the Compensation Committee's assessment of Mr. Reger and Mr. Gilbertson's contributions to the Company's notable accomplishments during 2009, including the closing of a $25 million credit facility with CIT, raising over $70 million in equity capital at accretive levels, increasing production and revenues from 2008 to 2009, efficiently expanding the Company's acreage position throughout 2009 and realizing nearly a 400% stock appreciation from the lows of March 2009. The Compensation Committee concluded that the achievement of these qualitative factors qualified Mr. Reger and Mr. Gilbertson for a significant year-end bonus, consistent with bonus compensation of the highest paid executive officers from the Company's peers. The Compensation Committee then examined the compensation policies and practices of various publicly-traded oil and gas exploration and production companies which the Compensation Committee deemed as peer companies to determine the appropriate year-end bonus compensation amounts for the 2009 fiscal year, including (in alphabetical order) Abraxas Petroleum Corp., Callon Petroleum Co., Carrizo Oil & Gas, Inc., Double Eagle Petroleum Co., Energy XXI (Bermuda) Limited, EV Energy Partners LP, GMX Resources Inc., Goodrich Petroleum Corp., Kodiak Oil and Gas, PetroQuest Energy Inc., Rex Energy Corporation Stone Energy Corp. and Swift Energy Co.

2009 Equity Incentive Plan

In 2009, the Board adopted and the stockholders approved the 2009 Equity Incentive Plan (the "Plan"). The Plan is designed to enable our company to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors. The Plan is administered by our Compensation Committee.

The Plan permits grants of both options to purchase common stock and restricted shares of our common stock. Stock options granted under the Plan may be either incentive stock options, which qualify for favorable tax treatment under Section 422 of the Internal Revenue Code, or nonqualified stock options, which do not qualify for favorable tax treatment. The Plan permits grants of options to any employee, non-employee director, consultant or advisor of our company or its subsidiaries.

A total of 3,000,000 shares of our common stock are reserved for issuance pursuant to awards granted under the Plan. The maximum number of shares for which any person may be granted awards under the Plan is 500,000 shares annually. The maximum number of shares for which awards may be granted under the Plan to all persons in any calendar year shall be limited to ten percent (10%) of the total outstanding shares of our common stock. Upon a "change in control" of the Company, all outstanding options granted under the Plan immediately vest and become immediately exercisable in full and all grants of restricted stock issued under the Plan become immediately fully-vested and free of all forfeiture and transfer restrictions.

On February 23, 2009, the Compensation Committee approved (subject to shareholder approval of the Plan, which was subsequently obtained) the issuance of 75,000 shares of common stock to each of Mr. Winter and Mr. Sankovitz, of which 45,000 shares were fully vested upon issuance and the remaining 30,000 of which were restricted shares that were to vest in two equal installments on January 1, 2010 and January 1, 2011. These grants were made in recognition of the contributions of Mr. Winter and Mr. Sankovitz since they were each initially hired by the Company and to further align their interests with those of our stockholders.

On November 30, 2009, the Compensation Committee approved the issuance of 150,000 shares of common stock to each of Mr. Reger and Mr. Gilbertson, of which 50,000 shares were fully vested upon issuance and the remaining 100,000 of which are restricted shares that vest in approximately equal installments on the first day of each month from January 2010 through December 2011. In addition, on November 30, 2009, the Compensation Committee approved the issuance of 25,000 shares of common stock to each of Mr. Winter and Mr. Sankovitz, all of which were fully vested upon grant and approved the acceleration and immediate vesting of 15,000 shares of restricted stock previously granted to each of Mr. Winter and Mr. Sankovitz, which were otherwise scheduled to vest on January 1, 2010. All such actions taken by the Compensation Committee were made in recognition of the named executive officers' contributions to the Company during 2009 and the Company's achievements during 2009 and to further align their interests with those of our stockholders. The stock bonus amount was determined by the Compensation Committee on a post hoc basis based on the Compensation Committee's assessment of management's contributions to the Company's notable accomplishments during 2009. The Compensation Committee's process is more fully described above under the heading "Compensation Discussion and Analysis – 2009 Cash Bonuses".

On March 17, 2010, the Compensation Committee approved the issuance of 250,000 shares of common stock to each of Mr. Reger, Mr. Gilbertson, Mr. Winter and Mr. Sankovitz. Each such grant consisted of 12,500 shares that were fully vested upon issuance and 237,500 restricted shares that will vest in quarterly installments from July 1, 2010 through January 1, 2014. The first three quarterly vesting installments are for 12,500 shares each, the next eight quarterly vesting installments are for 15,625 shares each and the final four quarterly vesting installments are for 18,750 shares each. Such grants were made in order to significantly increase each executive officer's personal stake in the Company, thereby further aligning their interests with those of our stockholders. In addition, the four year vesting period will provide our executive officers with a strong incentive to remain with the Company for the long-term. The Compensation Committee examined the compensation policies and practices of various publicly-traded oil and gas exploration and production peer companies which the Compensation Committee deemed as peer companies when determining year-end bonus compensation amounts for the 2009 fiscal year, including (in alphabetical order) Abraxas Petroleum Corp., Callon Petroleum Co., Carrizo Oil & Gas, Inc., Double Eagle Petroleum Co., Energy XXI (Bermuda) Limited, EV Energy Partners LP, GMX Resources Inc., Goodrich Petroleum Corp., Kodiak Oil and Gas, PetroQuest Energy Inc., Rex Energy Corporation Stone Energy Corp. and Swift Energy Co. This examination was used in addition to the annual accomplishment and performance metrics to determine the yearly compensation amounts for the Company's management in 2009. The Compensation Committee also engaged BDO Seidman, as an independent consultant to prepare an analysis of peer company compensation practices when implementing a one-time four-year incentive plan for the Company's executive management. The four-year incentive plan represents a multi-year plan designed to incentivize the Company's executive team over a long-term basis. As such, the Compensation Committee deemed it appropriate to broaden the peer group from the group used in determining year-end compensation to include various companies implementing long-term plans similar to the plan then contemplated by our Compensation Committee. BDO Seidman agreed that the broader peer group was appropriate for use in determining long-term grants. BDO Seidman concluded that the award of equity, in combination with prior year awards and a continuation of cash compensation at levels suggested by our Compensation Committee, sets our executive officers' compensation at market-competitive levels for the next four years, and the vesting terms of the awards establish a meaningful incentive to remain with our Company.

Employment Contracts, Termination of Employment and Change-in-Control

In January 2008, we entered into employment agreements with Mr. Reger and Mr. Gilbertson covering their service as our Chief Executive Officer and Chief Financial Officer, respectively. In November 2007 and March 2008, we entered into employment agreements with Chad D. Winter and James R. Sankovitz, respectively, as a condition to their employment with our company. On January 30, 2009, our board of directors and Compensation Committee approved certain amendments to all employment agreements, which were effectuated through adopting amended and restated employment agreements. In March 2010, Mr. Winter and Mr. Sankovitz were promoted to executive officer positions with the Company and in connection therewith entered into new employment agreements.

General Employment Agreement Provisions

The current employment agreements entitle Messrs. Reger, Gilbertson, Winter and Sankovitz to each receive an annual base salary as determined by our Compensation Committee, but which shall increase each year a minimum of four percent (4.0%) over the prior year's annual salary. All officers are eligible to receive bonus compensation at the discretion of our Compensation Committee or board of directors based upon meeting or exceeding established performance objectives. The employment agreements also contain provisions prohibiting our named executive officers from competing with our company or soliciting any employees of our company for a period of one year following termination of their employment in the event either officer terminates his employment with our company.

The current employment agreements have a three-year term commencing January 30, 2009 for Messrs. Reger and Gilbertson and March 25, 2010 for Messrs. Winter and Sankovitz, which term automatically renews for an additional three-year term each year unless otherwise terminated by either the Company or the employee. Notwithstanding the specified term, each employee's employment with our company is entirely "at-will," meaning that either the employee or our company may terminate such employment relationship at any time for any reason or for no reason at all, subject to the provisions of the then-applicable employment agreements.

Change-in-Control and Similar Provisions

The Compensation Committee utilized change of control provisions that were previously approved by the Company's Board of Directors as part of the Company's executive employment agreements. These provisions initially were suggested by the Company's outside legal counsel at the time the Company entered into employment agreements with Michael L. Reger and Ryan R. Gilbertson based on common practices of similarly situated companies, and have been utilized consistently by the Company and the Compensation Committee since that time.

The current employment agreements of each named executive officer contain change-in-control provisions entitling the employees to certain payments under specified circumstances. A “change-in-control” is defined as any one or more of the following:

- The consummation of a reorganization, merger, share exchange, consolidation or similar transaction, or the sale or disposition of all or substantially all of the assets of our company, unless, in any case, the persons beneficially owning the voting securities of our company immediately before that transaction beneficially own, directly or indirectly, immediately after the transaction, at least seventy-five percent (75%) of the voting securities of our company or any other corporation or other entity resulting from or surviving the transaction in substantially the same proportion as their respective ownership of the voting securities of our company immediately prior to the transaction;

- Individuals who constitute the incumbent board of directors cease for any reason to constitute at least a majority of the board of directors; or

- Our stockholders approve a complete liquidation or dissolution of our company.

Upon a change-in-control of our company, each employee’s employment agreement will immediately cease and our employees will be entitled to certain specified compensation.

In the event of a change-in-control, upon the earlier to occur of their death or six (6) months following the “change in control” we must pay each of our named executive officers a lump sum payment equal to twice their then-applicable annual salary in lieu of any and all other benefits and compensation to which they otherwise would be entitled. Messrs. Reger, Gilbertson, Winter and Sankovitz also are entitled to the pre-payment of the remaining lease term of their company vehicle and use of such vehicle through the remaining lease term of such vehicle, along with a lump sum payment of the estimated insurance premiums for such vehicle through the remaining lease terms upon a change-in-control.

In addition to the cash payments referenced above, upon any change-in-control our company or its successor must pay and/or issue (as appropriate) to both Messrs. Winter and Sankovitz that amount of cash and/or that number of shares of our common stock or shares of capital stock or ownership interests of any other entity which they would have been entitled to receive in connection with the change-in-control had they owned an aggregate of 30,000 fully-paid and non-assessable shares of our common stock prior to the change-in-control.

Assuming a change-in-control had occurred as of December 31, 2009 and assuming then-applicable base salaries, Messrs. Reger and Gilbertson each would have been entitled to receive a lump sum cash payment of $570,000 and each of Messrs. Winter and Sankovitz would have been entitled to receive a lump sum cash payment of $310,000. In addition, Messrs. Reger and Gilbertson each would have been entitled to payment of approximately $7,000 toward their vehicle lease and related insurance and Messrs. Winter and Sankovitz each would have been entitled to payment of approximately $11,000 toward their vehicle lease and related insurance. At December 31, 2009, the value of stock or similar change-in-control compensation to be awarded to both Messrs. Winter and Sankovitz would have approximated $360,600.

Our Compensation Committee carefully reviewed and considered the foregoing change-in-control provisions before approving the current employment agreements of each of our named executive officers. In addition, our Compensation Committee Chairperson—Lisa Meier—was involved in reviewing and negotiating draft employment agreements in advance of the full Committee review and approval.

Grants of Plan-Based Awards

The following table sets forth grants of plan-based awards during the year ended December 31, 2009, which consisted solely of grants of common stock and restricted common stock. All grants were made pursuant to the 2009 Equity Incentive Plan.

Name	Grant Date	Compensation Committee Approval Date	Number of Shares of Common Stock	Grant Date Fair Value of Stock Awards ($)	
Michael L. Reger	12/7/2009	11/30/2009	150,000	1,455,000	
Ryan R. Gilbertson	12/7/2009	11/30/2009	150,000	1,455,000	
Chad D. Winter	2/23/2009	2/23/2009	75,000	213,000	(a)
	11/30/2009	11/30/2009	25,000	228,750	
James R. Sankovitz	2/23/2009	2/23/2009	75,000	213,000	(b)
	11/30/2009	11/30/2009	25,000	228,750	

(a) On November 30, 3009, the Compensation Committee approved a modification of this award, such that 15,000 shares of restricted common stock that would have otherwise vested on January 1, 2010 instead vested on November 30, 2009. There was no incremental fair value related to the November 30, 2009 modification of the award.

(b) On November 30, 3009, the Compensation Committee approved a modification of this award, such that 15,000 shares of restricted common stock that would have otherwise vested on January 1, 2010 instead vested on November 30, 2009. There was no incremental fair value related to the November 30, 2009 modification of the award.

Outstanding Equity Awards

The following table sets forth the outstanding equity awards to our named executive officers as of December 31, 2009.

Name	Stock Awards Number of Shares That Had Not Vested		Market Value of Shares That Had Not Vested(a)
Michael L. Reger	100,000	(b)	$1,184,000
Ryan R. Gilbertson	100,000	(c)	$1,184,000
Chad D. Winter	15,000	(d)	$177,600
James R. Sankovitz	15,000	(e)	$177,600

(a) The values in this column are based on the $11.84 closing price of our common stock on the NYSE AMEX Equities Market on December 31, 2009.

(b) Consists of restricted common stock granted to Mr. Reger on December 7, 2009. 4,167 shares will vest on the first day of each month from January 2010 through November 2011 and the final 4,159 shares will vest on December 1, 2011.

(c) Consists of restricted common stock granted to Mr. Gilbertson on December 7, 2009. 4,167 shares will vest on the first day of each month from January 2010 through November 2011 and the final 4,159 shares will vest on December 1, 2011.

(d) Consists of restricted common stock granted to Mr. Winter on February 23, 2009. All 15,000 shares will vest on January 1, 2011.

(e) Consists of restricted common stock granted to Mr. Sankovitz on February 23, 2009. All 15,000 shares will vest on January 1, 2011.

Option Exercises and Stock Vested

Our named executive officers did not hold or exercise any stock options during the year ended December 31, 2009. The table below sets forth the number of shares of common stock acquired on vesting by our named executive officers during the year ended December 31, 2009.

	Stock Awards		
Name	Number of Shares Acquired on Vesting	Value Realized on Vesting	
Michael L. Reger	50,000	$485,000	(1)
Ryan R. Gilbertson	50,000	$485,000	(2)
Chad D. Winter	85,000	$493,800	(3)
James R. Sankovitz	105,000	$547,000	(4)

(1) Mr. Reger received a grant of 50,000 shares of fully vested common stock on December 7, 2009. The closing price of our common stock on the NYSE AMEX Equities Market on such date was $9.70.

(2) Mr. Gilbertson received a grant of 50,000 shares of fully vested common stock on December 7, 2009. The closing price of our common stock on the NYSE AMEX Equities Market on such date was $9.70.

(3) Mr. Winter received a grant of 45,000 shares of fully vested common stock on February 23, 2009. The closing price of our common stock on the NYSE AMEX Equities Market on such date was $2.84. Mr. Winter received a grant of 25,000 shares of fully vested common stock and had an additional 15,000 shares of restricted stock vest, on November 30, 2009. The closing price of our common stock on such date was $9.15.

(4) Mr. Sankovitz had 20,000 shares of restricted stock vest on January 2, 2009. The closing price of our common stock on the NYSE AMEX Equities Market on such date was $2.66. Mr. Sankovitz received a grant of 45,000 shares of fully vested common stock on February 23, 2009. The closing price of our common stock on such date was $2.84. Mr. Sankovitz received a grant of 25,000 shares of fully vested common stock and had an additional 15,000 shares of restricted stock vest, on November 30, 2009. The closing price of our common stock on such date was $9.15.

Defined Benefit Plans

We did not maintain any defined benefit plans during the year ended December 31, 2009.

Non-Employee Director Compensation

Our directors receive no cash fees for their services. Directors are, however, reimbursed for their actual out-of-pocket expenses associated with attending meetings and carrying out their obligations as directors.

On November 1, 2007, each of our non-employee directors received an option to purchase 100,000 shares of common stock pursuant to our 2006 Incentive Stock Option Plan. The options were fully vested at the time of grant and are exercisable at $5.18 per share, which represents the fair market value of our common stock on the date of grant, calculated based on the average close/last trade price of our common stock reported for the five highest volume trading days during the 30-day trading period ending on the last trading day preceding the date of grant (rounded to the nearest penny).

On December 7, 2009, each of our non-employee directors received a grant of 25,000 shares of common stock pursuant to our 2009 Equity Incentive Plan, of which 8,334 shares were fully vested upon issuance and the remaining 16,666 are restricted shares that vest in approximately equal installments on the first day of each month from January 2010 through December 2011.

The following table contains compensation information for our non-employee directors for the year ended December 31, 2009.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)(2)	Option Awards ($)(3)	Total ($)
Robert Grabb	–	242,500	–	242,500
Jack E. King	–	242,500	–	242,500
Lisa Meier	–	242,500	–	242,500
Loren J. O'Toole	–	242,500	–	242,500
Carter Stewart	–	242,500	–	242,500

(1) Each non-employee director received a grant of 8,334 shares of common stock and 16,666 shares of restricted common stock, on December 7, 2009. Valuation of awards based on the grant date fair value of those awards computed in accordance with FASB ASC Topic 718 utilizing assumptions discussed in note 8 to our consolidated financial statements for the fiscal year ended December 31, 2009.

(2) As of December 31, 2009, each non-employee director held 16,666 shares of unvested restricted common stock.

(3) As of December 31, 2009, each of Mr. King, Ms. Meier and Mr. O'Toole held stock options to purchase 100,000 shares of common stock at $5.18 per share and each of Mr. Grabb and Mr. Stewart held no stock options.

COMPENSATION COMMITTEE REPORT

Compensation Committee Activities

The Compensation Committee of our board consists of three independent directors. As the Compensation Committee, we authorize and evaluate programs and, where appropriate, establish relevant performance criteria to determine management compensation. Our Compensation Committee Charter grants the Compensation Committee full authority to review and approve annual base salary and incentive compensation levels, employment agreements and benefits of executive officers and other key employees. We intend to adopt performance criteria to measure the performance of our executive management and determine the appropriateness of awarding year-end cash bonuses based on performance company performance.

Employment Agreements

All employees, including the officers named in the summary compensation table, have entered into written employment agreements with our company. All such agreements provide that year-end cash bonuses are at the discretion of the Compensation Committee or board of directors, to be determined according to our company's achievement of specified predetermined and mutually agreed upon performance objectives each year.

Compensation Committee Interlocks and Insider Participation

There are no compensation committee interlocks.

Review of Compensation Discussion and Analysis

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis presented on the preceding pages. Based on its review and discussions, the Compensation Committee recommended to the board of directors that the Compensation Discussion and Analysis be included in the Company's proxy statement for its 2010 Annual Meeting of Stockholders.

The name of each person who serves as a member of our Compensation Committee is set forth below.

Loren J. O'Toole	Robert Grabb	Lisa Meier

AUDIT COMMITTEE REPORT

The Audit Committee of the board consists of three members who are neither officers nor employees of our company and who meet NYSE Amex independence requirements. Information as to these persons, as well as their duties, is provided under the caption “Our board of directors and Committees.” The Committee met eight times during 2009 and reviewed a wide range of issues, including the objectivity of the financial reporting process and the adequacy of internal controls. The Committee ratified the selection of Mantyla McReynolds LLC (“Mantyla McReynolds”) as our independent registered public accounting firm and considered factors relating to its independence. In addition, the Committee received reports and reviewed matters regarding ethical considerations and business conduct and monitored compliance with laws and regulations. Prior to filing our annual report on Form 10-K, the Committee also met with our management and internal auditors and reviewed the current audit activities, plans and results of selected internal audits. The Committee also met privately with the internal auditors and with representatives of Mantyla McReynolds to encourage confidential discussions as to any accounting or auditing matters.

The Audit Committee has (a) reviewed and discussed with management and representatives of our company’s independent registered public accountants our company’s audited financial statements contained for the year ended December 31, 2009; (b) discussed with our company’s independent registered public accountants the matters required to be discussed by the statement on Auditing Standards No. 61, as amended (AICPA, Professional Standards, Vol. 1. AU Section 380), as adopted by the Public Company Accounting Oversight Board (the “PCAOB”) in Rule 3200T; and (c). received the written disclosures and the letter from our company’s independent registered public accounting firm as required by applicable requirements of the PCAOB regarding the independent accountant’s communications with the audit committee concerning independence and discussed with representatives of our company’s independent registered public accounting firm its independence.

Based on the review and discussions referred to above, the Audit Committee recommended to the board of directors that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2009, for filing with the SEC.

The name of each person who serves as a member of our Audit Committee is set forth below.

Loren J. O’Toole	Robert Grabb	Lisa Meier

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

As an oil and gas exploration company, our business strategy is to identify and exploit resources in and adjacent to existing or indicated producing areas that can be quickly developed and put in production at low cost. We are focused on low overhead and, thus, have relied upon various relationships with third-parties that assist us in identifying and acquiring property in the most exciting new plays in a nimble and efficient fashion. As a consequence, we have entered into and may in the future enter into, certain transactions and arrangements with parties that have a direct or indirect relationship with one or more members of our management or board of directors.

A majority of the members of our board of directors have qualified as “independent” as defined in Section 803(a)(2) of the NYSE Amex company guide since September 2007 and our board of directors has approved any and all transactions involving any material obligation by our company to any party. See Directors—Independence and Committees above for a complete discussion regarding our Audit Committee and the independence of our directors. Our Audit Committee Charter, as amended March 18, 2008, and the NYSE Amex company guide require that Audit Committee review and approve all material transactions between our company and its directors, officers and 5% or greater stockholders, as well as all material transactions between our company and any relative or affiliate of any of the foregoing. In reviewing such transactions, the Audit Committee generally seeks third-party data to assist in evaluating whether the specific terms and provisions of each individual transaction are no less favorable to us than we could obtain from unaffiliated third parties. The Audit Committee historically has relied upon data from state and federal lease auctions to support the appropriateness of prices paid to any related party in connection with any leasehold acquisition. We anticipate that our Audit Committee will review and approve or ratify future transactions involving any executive officer, director, 5% or greater stockholder or any relative or affiliate of any of the foregoing.

In September 2007, we commenced a continuous lease program with South Fork Exploration, LLC (“SFE”), a Montana limited liability company owned and managed by J.R. Reger, brother of our Chief Executive Officer and Chairman—Michael Reger. The Company’s continuous lease program with SFE involved the acquisition of acreage in specific agreed upon sections of townships and ranges in North Dakota where SFE previously leased acreage on the Company’s behalf and is authorized to continue to acquire additional acreage within the proximity of the originally-acquired leases. The program has resulted in the acquisition of approximately 6,812 net acres across Burke and Divide Counties, approximately 624 net acres in Dunn County, approximately 56 net acres in Mercer County, and approximately 13,820 net acres in Mountrail County of North Dakota. This program differs from other arrangements where the Company may purchase specific leases in one-time, single closing transactions. SFE is compensated for the leases through a $13.00 cash payment per net acre and an over-riding royalty interest equal to the difference between the royalty payable to each lessor. The Company is receiving 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. Because each lessor separately negotiates its own desired royalty, SFE’s over-riding royalty interest varies from lease to lease. Under the terms of the program, we paid SFE an aggregate of $501,603 in 2009. J.R. Reger is also a stockholder of our company.

On January 30, 2009, our Compensation Committee and Audit Committee approved the issuance of non-negotiable, unsecured subordinated promissory notes in the principal amount of $370,000 to both Mr. Reger and Mr. Gilbertson in lieu of paying cash bonuses earned in 2008.

On November 17, 2009, the Audit Committee approved the opening of an investment account with Morgan Stanley Smith Barney LLC for management of a portion of the company’s excess cash. This account will be managed by Kathleen Gilbertson, a financial advisor with that firm who is the sister of our President and Director, Ryan Gilbertson. Depending on liquidity needs, we expect to invest approximately $30 million to $60 million in this investment account and Kathleen Gilbertson’s personal interest in any such amount we invest is expected to be approximately $7,000 to $20,000, depending upon the specific investments chosen for our funds.

Except as disclosed above, we had no transactions during 2009 and none are currently proposed, in which we were a participant and in which any related person had a direct or indirect material interest.

Item 15. Exhibits and Financial Statement Schedules

(b) Exhibits:

Exhibit No.	Description	Reference
23.1	Consent of Independent Registered Public Accounting Firm Mantyla McReynolds LLC	Filed herewith
23.2	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
99.1	Report of Ryder Scott Company, LP.	Filed herewith

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: November 5, 2010 By: /s/ Michael L. Reger
Michael L. Reger
Chief Executive Officer

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 and Director	November 5, 2010
/s/ Chad D. Winter Chad D. Winter	Chief Financial Officer, Principal Financial Officer and Principal Accounting Officer	November 5, 2010
* Ryan R. Gilbertson	President and Director	November 5, 2010
* Loren J. O'Toole	Director	November 5, 2010
* Carter Stewart	Director	November 5, 2010
* Jack King	Director	November 5, 2010
* Robert Grabb	Director	November 5, 2010
*	Director	

Lisa Bromiley Meier	November 5, 2010

* Michael L. Reger, by signing his name hereto, does hereby sign this document on behalf of the above-named directors of the Registrant pursuant to powers of attorney duly executed by such persons.

By: /s/ Michael L. Reger
Michael L. Reger
Attorney-in-Fact

NORTHERN OIL AND GAS, INC.

INDEX TO FINANCIAL STATEMENTS

NORTHERN OIL AND GAS, INC.
STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2009, 2008, AND 2007

	Year Ended December 31, 2009	2008 Adjusted *	2007
REVENUES			
Oil and Gas Sales	$15,171,824	$3,542,994	$-
Gain (Loss) on Settled Derivatives	(624,541)	778,885	-
Mark-to-Market of Derivative Instruments	(363,414)	-	-
Other Revenue	37,630	-	-
	14,221,499	4,321,879	-
OPERATING EXPENSES			
Production Expenses	754,976	70,954	-
Production Taxes	1,300,373	203,182	-
General and Administrative Expense	3,686,330	2,091,289	4,509,743
Depletion of Oil and Gas Properties	4,250,983	677,915	-
Depreciation and Amortization	91,794	67,060	3,446
Accretion of Discount on Asset Retirement Obligations	8,082	1,030	-
Total Expenses	10,092,538	3,111,430	4,513,189
INCOME (LOSS) FROM OPERATIONS	4,128,961	1,210,449	(4,513,189)
OTHER INCOME	135,991	383,891	207,896
INCOME (LOSS) BEFORE INCOME TAXES	4,264,952	1,594,340	(4,305,293)
INCOME TAX PROVISION (BENEFIT)	1,466,000	(830,000)	-
NET INCOME (LOSS)	$2,798,952	$2,424,340	$(4,305,293)
Net Income (Loss) Per Common Share - Basic	$0.08	$0.08	$(0.18)
Net Income (Loss) Per Common Share - Diluted	$0.08	$0.07	$(0.18)
Weighted Average Shares Outstanding – Basic	36,705,267	31,920,747	23,667,119
Weighted Average Shares Outstanding - Diluted	36,877,070	32,653,552	23,667,119

*See Note 2

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

NORTHERN OIL AND GAS, INC.
SELECTED NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2009

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP").

Cash and Cash Equivalents

The Company 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. Our cash positions represent assets held in checking and money market accounts. These assets are generally available to us on a daily or weekly basis and are highly liquid in nature. Due to the balances being greater than $250,000, we do not have FDIC coverage on the entire amount of bank deposits. The company believes this risk is minimal. In addition, we are subject to Security Investor Protection Corporation (SIPC) protection on a vast majority of our financial assets.

Short-Term Investments

All marketable debt and equity securities and 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 are 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 are included in accumulated other comprehensive income (loss). When securities are sold, their cost is determined based on the first-in first-out method. The realized gains and losses related to these securities are included in other income in the statements of operations.

Other Property and Equipment

Property and equipment that are not oil and gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to five years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. We have not recognized any impairment losses on non oil and gas long-lived assets. Depreciation expense was $91,794, $67,070, and $3,446 for the years ended December 31, 2009, 2008, and 2007.

Debt Issuance Costs

In February 2009, the Company entered into a revolving credit facility with CIT Capital USA, Inc. (CIT) (See Note 9). The Company incurred costs related to this facility that were capitalized on the Balance Sheet as Debt Issuance Costs. Included in the Debt Issuance Costs are direct costs paid to third parties for broker fees and legal fees, 180,000 shares of restricted common stock paid as additional compensation for broker fees, and the fair value of 300,000 warrants issued to CIT. The fair value of the warrants was calculated using the Black-Scholes valuation model based on factors present at the time of closing. CIT can exercise these warrants at any time until the warrants expire in February 2012. The exercise price of the warrants is $5.00 per warrant. The total amount capitalized for Debt

Issuance Costs is $1,670,000. The capitalized costs are being amortized for three years over the term of the facility using the effective interest method. In May 2009, the Company amended the revolving credit facility with CIT to allow for additional borrowings. The Company incurred $216,414 of direct costs related to this amendment. The capitalized costs will be amortized over the remaining term of the facility using the effective interest method.
The amortization of debt issuance costs for the year ended December 31, 2009 was $459,343.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which the asset is acquired 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.

Revenue Recognition and Gas Balancing

We recognize oil and gas revenues from our 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. We use the sales method of accounting for gas balancing of gas production and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of December 31, 2009 and 2008, our gas production was in balance, i.e., our cumulative portion of gas production taken and sold from wells in which we have an interest equaled our entitled interest in gas production from those wells.

Stock-Based Compensation

The Company has accounted for stock-based compensation under the provisions of FASB Accounting Standards Codification (ASC) 718-10-55 (Prior authoritative literature: FASB Statement 123(R), Share-Based Payment). This statement requires us to record an expense associated with the fair value of stock-based compensation. We use 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.

Income Taxes

The Company accounts for income taxes under FASB ASC 740-10-30 (Prior authoritative literature, FASB Statement 109, Accounting for 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 requires 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.

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 on the instruments issued in exchange for such services, whichever is more readily determinable, using the measurement date guidelines enumerated in FASB ASC 505-50-30 (Prior authoritative literature, EITF 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring or in Conjunction with Selling, Goods, or Services).

Net Income (Loss) Per Common Share

Net Income (Loss) per common share is based on the Net Income (Loss) divided by weighted average number of common shares outstanding.

Diluted earnings per share are computed using weighted average number of common shares plus dilutive common share equivalents outstanding during the period using the treasury stock method. As the Company has a loss for the period ended December 31, 2007 the potentially dilutive shares were anti-dilutive and were thus not added into the earnings per share calculation.

Full Cost Method

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration and development of oil and 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, 2009, 2008, and 2007:

	Year Ended December 31,		
	2009	2008	2007
Capitalized Certain Payroll and Other Internal Costs	$2,616,262	$1,374,071	$-
Capitalized Interest Costs	624,717	-	-
Total	$3,240,979	$1,374,071	$-

As of December 31, 2009 we controlled acreage in Sheridan County, Montana with primary targets including the Red River and Mission Canyon. We controlled acreage in North Dakota, primarily in Mountrail County, targeting the Bakken Shale and Three Forks/Sanish as well as acreage in Yates County, New York that is prospective for Marcellus Shale and Trenton-Black River natural gas production. See Note 5 for explanation of activities on these properties.

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 year ended December 31, 2008, the Company sold acreage for $468,609. The proceeds for these sales were applied to reduce the capitalized costs of oil and 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, asset retirement costs under FASB ASC 410-20-25 (Prior authoritative literature:, FASB Statement 143, Accounting for Asset Retirement Obligations) 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 calculations.

Capitalized costs of oil and 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 oil and gas reserves plus the cost of unevaluated 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 12-month average price of oil and natural gas to estimated future production of proved oil and 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. To this point the Company has not realized any impairment of its properties due to our low basis in the acreage and productivity and economics of our producing wells.

Use of Estimates

The preparation of financial statements under generally accepted accounting principles (“GAAP”) in the United States 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 oil and natural gas reserve volumes, future development costs, estimates relating to certain 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.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts in order to conform with the current year presentation. These reclassifications did not impact our net income, stockholders' equity or cash flows.

Derivative Instruments and Price Risk Management

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

At the inception of a derivative contract, the Company historically designated the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documented the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company historically measured hedge effectiveness on a quarterly basis and hedge accounting would be discontinued prospectively if it determined that the derivative 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 the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative are recognized in earnings immediately. See Note 15 for a description of the derivative contracts which the Company executed during 2009.

Derivatives, historically, are recorded on the balance sheet at fair value and changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of hedge transaction. The Company's derivatives historically consist primarily of cash flow hedge transactions in which the Company is 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 other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedges was reflected in current period earnings as gain or loss from derivative. 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 are reported as cash flows from operating activities.

On November 1, 2009, due to the volatility of price differentials in the Williston Basin, the Company de-designated all derivatives that were previously classified as cash flow hedges and in addition, the Company has elected not to designate any subsequent derivative contracts as accounting hedges under FASB ASC 815-20-25 (Prior authoritative literature: FASB Statement 133, Accounting for Derivative Instruments and Hedging Activities). 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 and unrealized gains or losses are recorded as gain (loss) on derivatives net, as an increase or decrease in revenues on the Statement of Operations rather than as a component of other comprehensive income (loss) or other Income (expense).

Impairment

FASB ASC 360-10-35-21 (Prior authoritative literature, FASB Statement 144, Accounting for the Impairment and Disposal of Long-Lived Assets), requires that long-lived assets to be held and used be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Oil and gas properties accounted for using the full cost method of accounting (which we use) 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, 2009, 2008, and 2007.

Change in Accounting Principle Related to Drilling Costs

In 2009, the Company changed its method of accounting for drilling costs from the accrual of drilling costs at the time drilling commenced for a well to recording the costs when amounts are invoiced by operators. Recording drilling costs when the amounts are invoiced by operators is deemed preferable as it better represents the Company's actual drilling costs. The recording of drilling costs in this method also is consistent with other companies in the oil and gas industry. Generally accepted accounting principles require that the impact of the change in accounting be applied retrospectively to all periods presented. As a result, all prior period financial statements have been adjusted to give effect to the cumulative impact of this change.
The following Table shows the effects on the Company's Balance Sheet:

	Year Ended December 31, 2008,		
	As Reported	Adjusted	Effect of Change
Deferred Tax Asset - Current	$1,433,000	$1,390,000	$(43,000)
Oil and Gas Properties, Full Cost Method	55,680,567	47,260,838	(8,419,729)
Accumulated Depreciation and Depletion	856,010	748,421	(107,589)
Accrued Drilling Costs	8,419,729	-	(8,419,729)
Accumulated Deficit	$(2,021,649)	$(1,957,060)	$64,589

The following Table shows the effect on the Company's Statement of Operations:

	Year Ended December 31, 2008,		
	As Reported	Adjusted	Effect of Change
Depletion Expense	$785,504	$677,915	$(107,589)
Income Tax Provision (Benefit)	(873,000)	(830,000)	43,000
Net Income	$2,359,751	$2,424,340	$64,589
Earnings Per Share – Basic	$0.07	$0.08	$0.01
Earnings Per Share – Diluted	$0.07	$0.07	$-

The following Table shows the effect on the Company's Statement of Cash Flows:

	Year Ended December 31, 2008,		
	As Reported	Adjusted	Effect of Change
Net Income	$2,359,751	$2,424,340	$64,589
Depletion of Oil and Gas Properties	785,504	677,915	(107,589)
Income Tax Benefit	(873,000)	(830,000)	43,000
Increase in Accrued Drilling Costs	8,419,729	-	(8,419,729)
Increase in Oil and Gas Properties	(46,416,886)	(37,997,157)	8,419,729

There was no effect on the Company's Statement of Operations or Statement of Cash Flows for the year ended December 31, 2007. The Company did not commence production on its wells until 2008 and reported no Accrued Drilling Costs as of December 31, 2007.

New Accounting Pronouncements

In March 2008, the FASB issued FASB ASC 815-10-15 (Prior authoritative literature, FASB Statement 161, Disclosures About Derivative Instruments and Hedging Activities). FASB ASC 815-10-15 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity's financial position, financial performance, and cash flows. FASB ASC 815-10-15 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. Pursuant to the transition provisions of the Statement, the Company adopted FASB ASC 815-10-15 on January 1, 2009. The required disclosures are presented in Note 15 on a prospective basis. This Statement does not impact the financial results as it is disclosure-only in nature.

In April 2009, the FASB issued FASB ASC 270-10-05 (Prior authoritative literature: APB 28-1, Interim Disclosures About Fair Value of Financial Instruments). FASB ASC 270-10-05 amends FASB ASC 825-10-50 (Prior authoritative literature: FASB Statement 107, Disclosures About Fair Value of Financial Instruments) to require an entity to provide disclosures about fair value of financial instruments in interim financial information. FASB ASC 270-10-05 is to be applied prospectively and is effective for interim and annual periods ending after June 15, 2009 with early adoption permitted for periods ending after March 15, 2009. The required disclosures are presented in Note 13 on a prospective basis.

In February 2008, the FASB issued FASB ASC 820-10-65-1 (Prior authoritative literature: FSP FAS 157-2/Statement 157, Effective Date of FASB Statement No. 157.) FASB ASC 820-10-65-1 delayed the effective date for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of the provisions of FASB ASC 820-10-65-1 related to nonfinancial assets and nonfinancial liabilities on January 1, 2009 did not have a material impact on the Financial Statements. See Note 13 for FASB ASC 820-10-65-1 disclosures.

In April 2009, the FASB issued FASB ASC 820-10-65-4 (Prior authoritative literature: FASB Statement 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly). FASB ASC 820-10-65-4 provides additional guidance in estimating fair value, when the volume and level of transaction activity for an asset or liability have significantly decreased in relation to normal market activity for the asset or liability. FASB ASC 820-10-65-4 also provides additional guidance on circumstances that may indicate a transaction is not orderly. FASB ASC 820-10-65-4 is effective for interim periods ending after June 15, 2009, and the Company has adopted its provisions during second quarter 2009. FASB ASC 820-10-65-4 did not have a significant impact on the Company's financial position, results of operations, cash flows, or disclosures.

In April 2009, the FASB issued FASB ASC 320-10-65 (Prior authoritative literature: FSP FAS 115-2/124-2, Recognition and Presentation of Other-Than-Temporary Impairments). The guidance applies to investments in debt securities for which other-than-temporary impairments may be recorded. If an entity's management asserts that it does not have the intent to sell a debt security and it is more likely than not that it will not have to sell the security before recovery of its cost basis, then an entity may separate other-than-temporary impairments into two components: 1) the amount related to credit losses (recorded in earnings), and 2) all other amounts (recorded in other comprehensive income). This ASC is to be applied prospectively and is effective for interim and annual periods ending after June 15, 2009 with early adoption permitted for periods ending after March 15, 2009. The adoption of the provisions of this ASC in the second quarter 2009 did not have a material impact on the Financial Statements.

In June 2009, the FASB issued FASB ASC 860-10-05 (Prior authoritative literature: FASB Statement 166, Accounting for Transfers of Financial Assets). FASB ASC 860-10-05 is effective for fiscal years beginning after November 15, 2009. The Company is currently assessing the impact of FASB ASC 860-10-05 on its financial position and results of operations.

In June 2009, the FASB issued FASB ASC 810-10-25 (Prior authoritative literature: FASB Statement 167-Amendment to FIN 46(R), Consolidation of Variable Entities). FASB ASC 810-10-25 eliminates the quantitative approach previously required for determining the primary beneficiary of a variable interest entity and requires a qualitative analysis to determine whether an enterprise's variable interest gives it a controlling financial interest in a variable interest entity. FASB ASC 810-10-25 contains certain guidance for determining whether an entity is a variable interest entity. This statement also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. FASB ASC 810-10-25 will be effective as of the beginning of the Company's 2010 fiscal year. The Company is currently evaluating the impact of the adoption of FASB ASC 810-10-25.

In June 2009, the FASB issued FASB ASC 105-10-65 (Prior authoritative literature: FASB Statement 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles). Under FASB ASC 105-10-65, the FASB Accounting Standards Codification ™ (the "Codification") becomes the exclusive source of authoritative U.S. generally accepted accounting principles ("U.S. GAAP") recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission ("SEC") under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The Codification will supersede all then-existing non-SEC accounting and reporting standards, with the exception of certain non-SEC accounting literature which will become nonauthoritative. FASB ASC 105-10-65 is effective for the Company's 2009 third fiscal quarter. The adoption of FASB ASC 105-10-65 did not have a material impact on the Company's Financial Statements. All references to U.S. GAAP provided in the notes to the Financial Statements have been updated to conform to the Codification.

In October 2009, the FASB issued ASU No. 200-13, Revenue Recognition – Multiple Deliverable Revenue Arrangements ("ASU 2009-13"). ASU 2009-13 updates the existing multiple-element revenue arrangements guidance currently included in FASB ASC 605-25. The revised guidance provides for two significant changes to the existing multiple-element revenue arrangements guidance. The first change relates to the determination of when the individual deliverables included in a multiple-element arrangement may be treated as separate units of accounting. This change will result in the requirement to separate more deliverables within an arrangement, ultimately leading to less revenue deferral. The second change modifies the manner in which the transaction consideration is allocated across the separately identified deliverables. Together, these changes will result in earlier recognition of revenue and related costs for multiple-element arrangements than under previous guidance. This guidance expands the disclosures required for multiple-element revenue arrangements. Effective for interim and annual reporting periods beginning after December 15, 2009. The Company is currently evaluating the potential impact, if any, of this guidance on its financial statements.

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NOTE 5 OIL AND GAS PROPERTIES

Acquisitions

Montana Acquisitions

In February 2007, the Company acquired leasehold interests in approximately 22,000 net mineral acres in Sheridan County, Montana. The Company paid a combination of cash and stock as consideration for such acquisition, including the issuance of an aggregate of 400,000 restricted shares of its common stock.

At various points in 2009, we acquired leasehold interests in approximately 6,100 net mineral acres in development areas located in Roosevelt, Richland and Sheridan Counties Montana, in which we are targeting the Bakken Shale.
On November 13, 2009, we entered into a Letter of Intent with Slawson pursuant to which we agreed to acquire a twenty percent (20%) working interest ownership in the exploration and development of Slawson's Big Sky Project in Richland County, Montana for which Slawson controls leasehold interest in 13,401 gross acres and 11,586 net acres. For each well we elect to participate, we will pay a participation interest share of all costs to drill, equip, complete, test and plug such well(s) on an at cost basis.

North Dakota Acquisitions

At various points in late 2007 and throughout 2008, the Company acquired leasehold interests in approximately 21,498 net mineral acres of land via bulk purchases in the core development area of Mountrail County, North Dakota. The Company paid a combination of cash and stock as consideration for such acquisitions, including the issuance of an aggregate of 633,027 restricted shares of its common stock. In addition to these major acquisitions the Company completed a series of small transactions pursuant to which it purchased leasehold interests in approximately 8,000 net mineral acres in Mountrail County.

On June 11, 2008, the Company entered into a purchase agreement pursuant to which it ultimately acquired leasehold interests in approximately 23,210 net mineral acres primarily in Dunn County, North Dakota. The Company also completed various additional acquisitions of oil and gas leasehold interests through numerous small transactions with several parties in fiscal years 2007 and 2008.

At various points in 2007 and 2008, the Company purchased leasehold interests in approximately 10,000 net mineral acres in and around Burke and Divide Counties of North Dakota for cash consideration.

In May 2009, the Company entered into an exploration and development agreement with Slawson Exploration Company, Inc. (Slawson) pursuant to which the Company acquired certain North Dakota Bakken assets from Windsor Bakken LLC as part of a syndicate led by privately owned Slawson. Pursuant to the agreement, the Company purchased a five percent (5.0%) interest of the undeveloped acreage, including approximately 60,000 net acres. The Company also acquired an additional nine percent (9%) interest in the existing well bores purchased from Windsor Bakken LLC, providing the Company an aggregate fourteen percent (14%) interest in the existing 59 gross Bakken and Three Forks well bores in North Dakota including approximately 1,200 barrels of oil production per day. In the transaction, the Company purchased approximately 300,000 barrels of proven producing reserves as well as approximately 3,000 net undeveloped acres. The Company paid a total cost of $7,300,000 for the initial acquisition of acreage and well bore interests.

On November 3, 2009, along with Slawson Exploration we acquired 24 high working interest sections comprising approximately 12,000 net acres located in western McKenzie and Williams Counties of North Dakota. We acquired a 50% interest in these properties and will participate in drilling on a heads-up basis. These properties are proximal to several recent high-rate producing wells. We paid approximately $1,100 per net acre acquired in this acquisition and expect to begin drilling these properties in early 2011.

On November 17, 2009, we entered into an Exploration and Development Agreement with Area of Mutual Interest with Slawson pursuant to which we agreed to participate with a fifty percent (50%) working interest ownership, which equates to a thirty percent (30%) participation interest in the exploration and development of Slawson's Anvil Project in Roosevelt and Sheridan Counties, Montana and Williams County, North Dakota. In the transaction, we acquired an interest in 12,500 net acres in leases at $750 per net acre for a thirty percent (30%) interest and an aggregate sum of $2,812,500. We agreed to participate in all costs to drill, equip, complete, test and plug the well and to pay costs for the well on an at cost basis. We have the option to elect to participate or not participate as to each well drilled in the applicable project area. For each well in which we elect to participate, we will pay a participation interest share of all costs to drill, equip, complete, test and plug such wells on an at cost basis.

In addition to acquiring acreage through large block acquisitions, we have organically acquired approximately 4,000 net mineral acres in all of our key prospect areas in the form of both effective leases and top-leases. In this organic acquisition program we have spent an average of approximately $730 per net acre acquired.

The Company has also completed other miscellaneous non-material acquisitions in North Dakota, and utilized a combination of stock and cash consideration for some of the acquisitions.

New York Acquisition

In September 2007, the Company acquired leasehold interests in approximately 10,000 net mineral acres in the Appalachia Basin of New York. The Company paid a combination of cash and stock as consideration for such acquisition, including the issuance of an aggregate of 275,000 restricted shares of its common stock.

Certain of the foregoing acquisitions 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. See Note 7. All transactions involving related parties were approved by the Company's Board of Directors or Audit Committee.

Unevaluated Properties

The Company's unproved properties not being amortized are comprised of approximately 105,542 net acres of undeveloped leasehold interests that could result in over 165 net potential drilling locations based on one well per 640 acre spacing unit. The Company believes that the majority of our 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 we can explore or develop it further or by determining that further exploration and development activity will not occur.

Excluded costs for unevaluated 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, 2009 by year incurred.

	Year Ended December 31,		
	2009	2008	2007
Property Acquisition Costs	$17,478,196	$29,080,499	$5,147,236
Developmental Drilling Costs	394,066	1,762,532	-
Total	$17,872,262	$30,843,031	$5,147,236

The Company had 1.55 net wells drilling and completing as of December 31, 2009. All properties that have not yet commenced production are considered unevaluated properties and, thus, the costs associated with such properties are not subject to depletion. Once production commences for a well, all associated acreage and drilling costs are subject to depletion.

NOTE 7 RELATED PARTY TRANSACTIONS

The Company has purchased leasehold interests from South Fork Exploration, LLC ("SFE"). In 2009, the company paid a total of $501,603 related to a previously executed leasehold agreement. SFE's president is J.R. Reger, the brother of the Company's CEO, Michael Reger. J.R. Reger is also a shareholder in the Company.

The Company has also purchased leasehold interests from Montana Oil Properties ("MOP") for total consideration of approximately $62,234. MOP is controlled by Mr. Tom Ryan and Mr. Steven Reger, both are relatives of the Company's CEO, Michael Reger.

The Company has also purchased leasehold interests from Gallatin Resources, LLC for total consideration of approximately $22,223. Carter Stewart, one of the Company's directors, owns a 25% interest in Gallatin Resources, LLC.

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