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 establis